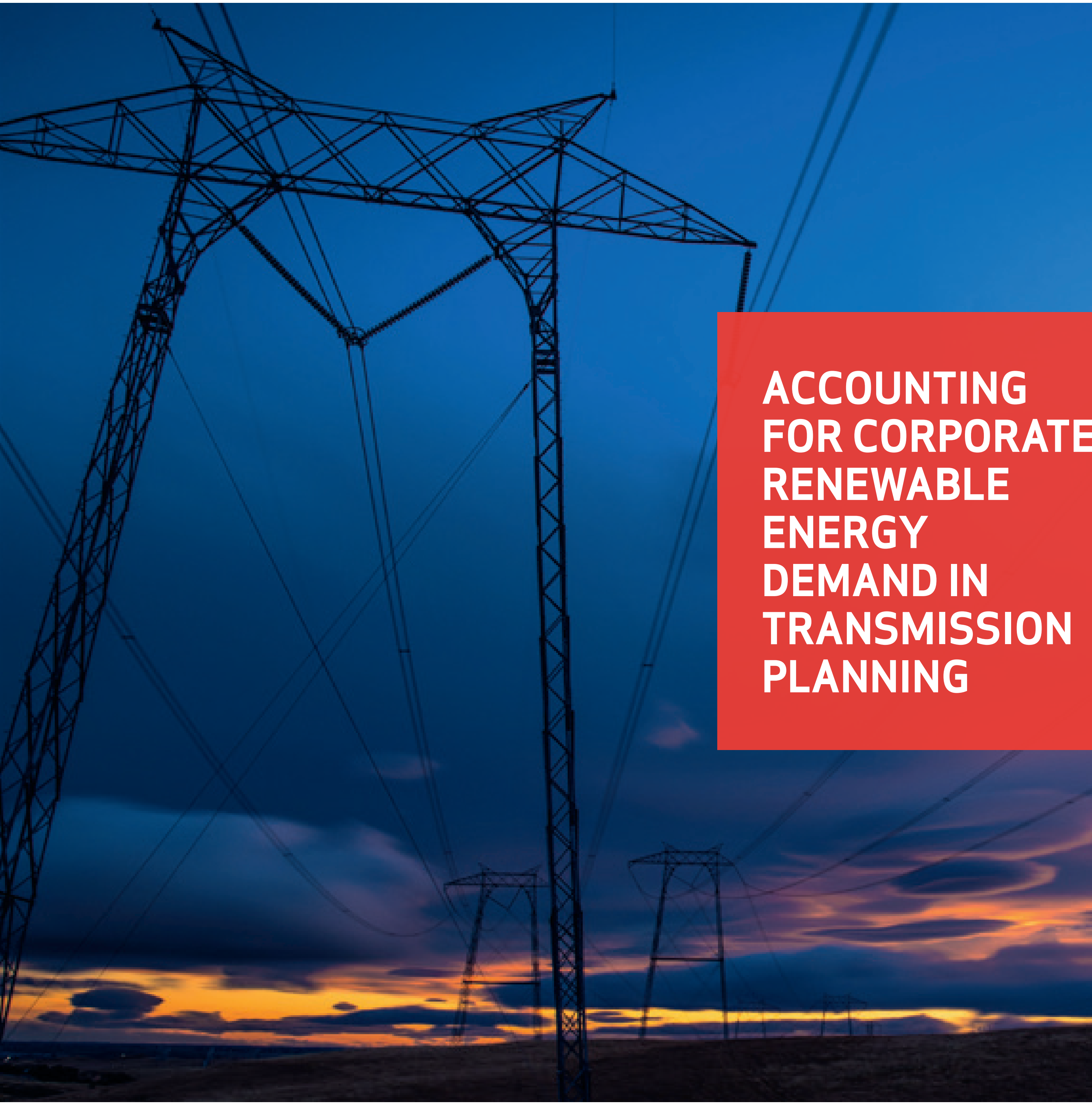
20 YEARS

EET&D MAGAZINE

March/April 2018 Issue 2 – Volume 22



ACCOUNTING FOR CORPORATE RENEWABLE ENERGY DEMAND IN TRANSMISSION PLANNING

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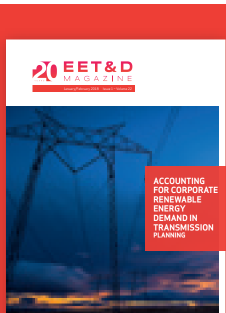

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ONE OF CANADA'S BEST DIVERSITY EMPLOYERS: HYDRO OTTAWA CREATING A CULTURE OF INCLUSION

March, 2018

Hydro Ottawa is proud to announce its selection as one of Canada's Best Diversity Employers. The company's commitment to diversity and inclusion has made it a role model in cultivating a culture of belonging thanks to its executive-sponsored Diversity Council and sub-groups.

Hydro Ottawa employees participating in the 2017 Capital Pride Parade (CNW Group/Hydro Ottawa Holding Inc.)

Hydro Ottawa employees participate in a panel discussion at the House of Commons on International Day of Persons with Disabilities (CNW Group/Hydro Ottawa Holding Inc.)

The company's comprehensive Diversity and Inclusion Plan works to attract, acquire, engage and retain diverse talent to spur innovation, drive growth and sustain competitive advantage. It also works to better reflect the communities it serves so as to enable it to offer additional customer value. The plan fosters a respectful and inclusive workplace.

Quick Facts

- Hydro Ottawa's overarching Diversity Council is led by two executive sponsors to implement the Diversity and Inclusion Plan, with participation from employee volunteers at all levels of the organization.
- The Diversity Council and sub-groups focus on tangible ways to advance workplace culture and gain insight from employees that self-identify as youth, women, people with disabilities, First Nations, LGBTQ+, members of visible minorities, and new Canadians.
- Hydro Ottawa was recently recognized as a National Capital Region Top Employer for the tenth consecutive year in 2018. This is the first time the company has earned this Best Diversity Employer accolade.
- In 2016, Hydro Ottawa was awarded with the Workplace Diversity and Inclusion Champion award from Electricity Human Resources Canada.
- Hire Immigrants Ottawa recognized the company with its Employer Excellence award in 2016.

"We are a better company when our employees feel deep in their bones that they can come to work as their true authentic selves. This award recognizes the work, passion and commitment of our employees to grow, have candid conversations, and challenge the status quo on important social issues in the workplace. I'm immensely proud of this award because it represents the best of who we are as a company and our shared values with our employees."

– Bryce Conrad, *President and Chief Executive Officer*

DTE ENERGY CEO GERRY ANDERSON RECEIVES PRESTIGIOUS CLIMATE LEADERSHIP AWARD

March, 2018

DTE Energy Chairman and CEO Gerry Anderson has been selected as the recipient of the Individual Climate Leadership award by the Center for Climate and Energy

Solutions (C2ES) and The Climate Registry for driving DTE Energy's goal to reduce carbon emissions by more than 80 percent by 2050.

Presented at the eighth annual Climate Leadership Conference in Denver, Anderson is among the first energy company CEOs to win the prestigious award, which honors exemplary corporate, organizational, and individual leadership in reducing carbon emissions and addressing climate change.

"Gerry Anderson is extremely deserving of the Climate Leadership Award," said Chris Kolb, president, Michigan Environmental Council. "His recognition that climate change is one of the defining public policy issues of our era and the defining issue within the energy industry is critical to the future health of the state of Michigan. He recognized the need for DTE Energy to take the lead in moving Michigan and the country forward to cleaner sources of energy that still provide reliable and affordable power for customers."

DTE Energy is Michigan's largest investor in renewable energy, having driven investments of $2 billion in wind farms and solar arrays since 2008, providing enough clean energy to power 450,000 homes. These investments helped DTE cut carbon emissions by nearly 25 percent in 2017 since 2005.

By continuing to incorporate substantially more renewable energy, transitioning its 24/7 power sources from coal to natural gas, continuing to operate its zero-emission Fermi 2 power plant, and improving options for customers to save energy and reduce bills, DTE plans to reduce carbon emissions by 45 percent by 2030, 75 percent by 2040 and more than 80 percent by 2050. These plans define a long-term shift by DTE to produce over three-quarters of its power from renewable energy and highly efficient natural gas-fired power plants.

"Fundamentally addressing climate change is among our greatest responsibilities," Anderson said. "Reducing our company's carbon footprint and developing cleaner sources of energy is a key priority for us. Over time, I suspect this work will also bring great opportunity - for example, when we invest to enable electric vehicles to drive similar transformation in the transportation sector."

DTE studied the engineering and the economics of Michigan's energy future for two years before announcing its 2050 carbon reduction goals - a timeframe that aligns with the target scientists broadly have identified as necessary to help address climate change.

DTE's plans include:

- The construction of an additional 4,000 megawatts of renewable energy capacity - enough to supply the energy for nearly 2 million homes - supplementing the 1,000 megawatts of renewable energy DTE has built since 2008.
- The steady retirement of the company's aging coal-fired plants, which continued in 2016 with the announced shutdown of 11 coal units by the early 2020s.
- The construction of a highly efficient, state-of-the-art natural gas-fired power plant of about 1,100 megawatts on existing company property in East China Township, Mich., that will, beginning in 2022, supply 24/7 power and ensure reliability as the coal plant retirements proceed.
- Continued investment in energy efficiency and energy waste reduction, helping customers to both save money and take greater control over their energy use.
- The investment of $5 billion over the next five years to modernize the electric grid and gas infrastructure, ensuring reliability while creating and supporting more than 10,000 Michigan jobs.
- An aggressive plan to reduce energy and water within DTE's own facilities by a minimum of 25 percent.

"We've concluded not only that the 80 percent reduction goal is achievable, it is achievable in a way that ensures Michigan's power is safe, secure, affordable, reliable - and sustainable," Anderson said. "There doesn't have to be a choice between a healthy environment and a healthy economy, although the debate often gets framed that way. We can have both, if we invest in a smart way."

The annual Climate Leadership Conference is dedicated to professionals addressing global climate change through policy, innovation, and business solutions. The conference gathers forward-thinking leaders from business, government, academia, and the non-profit community, to explore energy and climate related solutions, introduce new opportunities, and provide support to leaders taking action on climate change. The Climate Leadership Conference is hosted by the Center for Climate and Energy Solutions and The Climate Registry.


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FLORIDA POWER & LIGHT AUGMENTS FPL BABCOCK RANCH SOLAR ENERGY CENTER WITH ADVANCED BATTERIES, CREATING THE NATION'S LARGEST SOLAR-PLUS-STORAGE SYSTEM

March, 2018

Florida Power & Light Company announced another milestone in its long-term strategy of delivering affordable clean energy to customers: the creation of the largest solar-plus-storage system built in the U.S. to date.

This innovative system incorporates a 10-megawatt/ 40-megawatt-hour battery-storage project into the operations of the FPL Babcock Ranch Solar Energy Center, a 74.5-megawatt solar power plant that FPL built in 2016 in Charlotte County, Florida.

> *"FPL is building an incredible amount of solar power cost-effectively so we can bring the economic and environmental benefits to all of our customers while keeping their bills among the lowest in the nation. At the same time, we continue to innovate every single day, and the new system we unveiled today is a shining example of how we're changing the current,"*
>
> – Eric Silagy, president and CEO of FPL.

The batteries are capable of storing power generated by the FPL Babcock Ranch Solar Energy Center during the day when the sun is shining. The stored solar power then can be dispatched to the grid to supplement dips in the plant's operation - such as when clouds roll in and temporarily reduce the sunlight reaching the plant's panels. The stored power can also be dispatched during periods of peak customer electricity demand, such as summer afternoons and evening hours when the sun is going down but air conditioning needs remain high.

> *"FPL has been an outstanding partner in our mission to make Babcock Ranch the most innovative, sustainable town in the nation. Improving technologies for energy storage are moving us ever closer to our goal of full reliance on clean, renewable energy. As home to the largest solar-plus-storage system operating in America, we are proud to be leading the way,"*
>
> – Syd Kitson, chairman and CEO of Kitson & Partners and founder of the town of Babcock Ranch.

FPL and other NextEra Energy companies are actively researching and testing battery-storage technologies to study a variety of potential benefits ranging from grid stabilization to improved solar integration. Currently, NextEra Energy companies operate a total of approximately 140 megawatts of batteries with more than 150 megawatt-hours of storage capacity.

The cutting-edge project announced today is the latest in FPL's growing battery portfolio, which includes several projects across Florida.

Last month, FPL announced the first-of-its-kind large-scale application of "DC-coupled" batteries at a solar plant in the country - a 4-megawatt/16-megawatt-hour storage system located at the FPL Citrus Solar Energy Center in DeSoto County, Florida. During optimal operating periods, a solar plant may generate more power than its inverters can process. DC-coupled batteries can harness the surplus energy that would otherwise be lost or "clipped" by the inverter and could be an advantageous application in appropriate settings.

In 2016, FPL commissioned several battery-storage pilot projects to test different applications under real-world operating conditions. Systems are currently being tested at Everglades National Park's Flamingo Visitor

Center, the Crandon Tennis Center on the island of Key Biscayne as well as other locations across south Florida. Learnings from these pilots are being applied to FPL's future plans.

Under the rate agreement supported by the state's consumer advocate and approved unanimously by the Florida Public Service Commission in 2016, FPL plans to develop 50 megawatts of battery storage over the next few years.

Four new solar energy centers coming in 2019

FPL currently operates 14 solar power plants across Florida, and earlier this month, the company announced the locations of its next four new solar power plants, which are expected to begin powering customers by the spring of 2019. These new sites are:

- FPL Interstate Solar Energy Center, St. Lucie County
- FPL Miami-Dade Solar Energy Center, Miami-Dade County
- FPL Pioneer Trail Solar Energy Center, Volusia County
- FPL Sunshine Gateway Solar Energy Center, Columbia County

FPL's solar expansion plays a significant role in its forward-looking strategy of making smart investments that generate affordable clean energy for customers. FPL has been working for several years to find ways to reduce costs in order to bring more universal solar to its customers cost-effectively. This month, the company implemented a rate decrease, and its typical customer bill is now approximately 30 percent lower than the national average - lower than it was more than 10 years ago.

Each of the new solar plants will have a capacity of 74.5 megawatts. Combined, they are expected to generate enough energy annually to power approximately 60,000 homes and, over their operational lifetime, produce net savings for FPL customers of $40 million. The net savings are due to several factors including system fuel savings.

Construction is expected to commence later this year. At the height of construction, each of the sites is expected to employ about 200 people, for a total of approximately 800 jobs.

More information about solar in Florida and FPL's solar investments

Florida ranks ninth in the nation for solar resource - the strength of the sun's rays - making it a great place for solar. One of the cleanest electric utilities in the nation, FPL projects that solar will outpace coal and oil combined as a percentage of the company's energy mix by the year 2020.

FPL is in the midst of one of the largest solar expansions ever in the U.S. with more than 3.5 million new solar panels added in the last two years alone. From 2016 to 2023, FPL expects to install a total of more than 10 million solar panels. These advancements continue to improve FPL's carbon emissions profile, which is already approximately 30 percent cleaner than the U.S. industry average.

FPL has been studying and operating solar in Florida for more than three decades. In 1984, FPL commissioned its first universal solar installation, a 10-kilowatt photovoltaic facility in Miami that helped the company's employees gain experience with the then-emerging technology. Over the years, FPL has continued to test and operate a wide variety of solar technologies. In 2016, FPL became the first company to build solar cost effectively in Florida, leveraging its purchasing power and sites with key advantages to complete three 74.5-megawatt solar power plants projected to produce net savings for FPL customers.

POWER POINTS

DISTRIBUTECH 2018

ON DISPLAY

ELISABETH MONAGHAN
Editor in Chief

Since joining EE T&D last April as editor in chief, I have had the pleasure of interacting with dozens of industry partners and subject matter experts, but I have met only a handful of them in person. So when it came time to prepare for DistribuTECH 2018, I was delighted at the prospect of meeting many of these people in real life, learning more first-hand about their role in the power sector and exploring more about what they consider to be the most pressing or thought-provoking topics. With more than 500 exhibitors and thousands of conference attendees at DTECH, it was clear I would not be able to speak to all of those on my list. I did not realize how tight everyone's schedules would be.

As the EE T&D team entered the exhibit hall on Monday afternoon to drop off copies of our magazine and to set up our display, we were greeted by the shouting of various setup crews, as they strained be heard over the cacophony of hammers, forklifts and staple guns. There were countless piles of boxes and booth parts everywhere, and from the state of incompletion, it looked like it would be a long shot for the place to be set up by the time the exhibit hall opened the next morning. In spite of the pandemonium during the setup, and regardless of what looked like down-to-the-wire scrambling, when it came time for the doors to the exhibit hall to open on Tuesday, everyone and everything was in place and ready to go.

Included in the 15 conference tracks was one on microgrids. Microgrids are not new to the industry, but today, as more utilities and energy partners are looking to microgrids to bolster grid stability and resiliency, the conversation about what microgrids are and the potential they offer the market has become mainstream.

As a concept, microgrids make sense, but for conference attendees who wanted to gain an understanding of how they actually work, S&C Electric Company had an interactive, three-dimensional microgrid table on display. Not only was the microgrid table an effective tool to explain a rather complex process, but the accompanying sound effects also made for an entertaining demonstration. With thousands of individuals browsing the exhibitor floor S&C was successful at capturing and holding the attention of passers-by.

Of course, S&C was not the only exhibitor to draw a crowd by offering visually compelling displays and informative demonstrations. Delta Energy and Communications used a model of a miniature town to showcase the company's approach to smart city infrastructure through its smart grid network solution. The model demonstrated how a smart grid network, utilizing a Wi-Fi based WWAN (wireless wide area network) mesh with power metering hardware and software, can effectively deliver electrical distribution monitoring and analytics within a secure, cloud-based network. In a large space, where many conversations are occurring at once, it was challenging at times to follow along when exhibitors talked about their offerings. Simulations like Delta's model and S&C's demo made it easier to focus, so that I came away from our conversations with a better understanding of how these companies were addressing some of the industry's most significant challenges.

Sensus was another exhibitor whose notable demo garnered an enthusiastic reception from conference attendees, as well as repeat visitors, to its booth. Guests of the Sensus booth were encouraged to participate in a "fully immersive virtual reality experience," where they found themselves inside a virtual reality of network communication that presented real disruptions for them to battle. I had considered donning the special virtual reality glasses and experience this for myself, but there were a few people in line ahead of me, and I had five minutes to get to a meeting on the other side of the exhibit hall. From what seemed like an ever-lengthening queue of participants wanting their turn at the game, I clearly missed out on an activity that was educational and fun.

I went to DistribuTECH with the intention of speaking with a number of established contacts, while also making new acquaintances. It was a great plan, but the 30 minutes allotted for each meeting made it difficult to do more than touch base with only about half of those on my list. Next year, I will be more realistic about scheduling meetings at DistribuTECH so that I can spend more time at each booth.

I am hoping the IEEE PES T&D conference this April in Denver will present another chance to meet more of my existing contacts. In the meantime, here is what I told those I met DTECH who are interested in submitting articles to EE T&D: The magazine strives to address the industry's major issues and emerging trends, while also covering the projects or solutions transforming the industry. However, it is those who work in the energy sector every day who truly understand what matters most. If you feel EE T&D should cover a subject or industry trends, I hope that not only will you point it out but also if it is a topic on which you're an expert, you will allow us to share that valuable expertise with our readers.

If you would like to contribute an article or if you have an idea about interesting technology, solutions, or suggestions, please email me at

Elisabeth@ElectricEnergyOnline.com.

Elisabeth

ACCOUNTING FOR CORPORATE RENEWABLE ENERGY DEMAND

IN TRANSMISSION PLANNING

BY JOHN KOSTYACK AND DAVID GARDINER

Most experts agree that upgrading and expanding our nation's transmission infrastructure is a critical part of any investment plan for America's future. The American Society of Civil Engineers gives a D+ grade to the upkeep of our electricity system, noting that, "without greater attention to aging equipment, capacity bottlenecks and increased demand, as well as increasing storm and climate impacts, Americans will likely experience longer and more frequent power interruptions."

But determining the appropriate amount of transmission to build, and where to build it, is a complex process, made even more challenging by the many stakeholders involved at the federal, state and local levels. Most U.S. transmission projects take five to 10 years to build, and the delays and uncertainty can often create insurmountable hurdles for many badly needed projects.

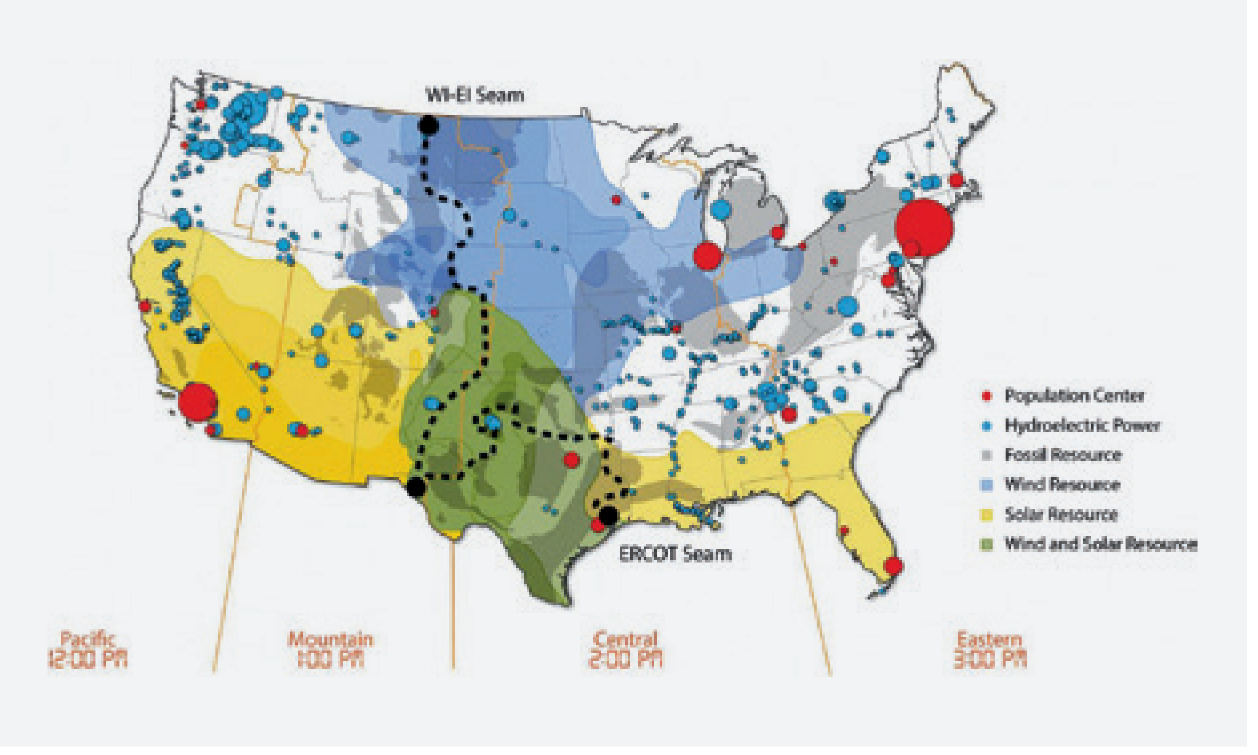
One of the keys to addressing our infrastructure backlog is planning by Regional Transmission Organizations (RTOs). Once a specific need is identified in an RTO plan, the chances that the transmission line will get financed and built go up dramatically. This is why we highlighted in our recent research report that RTOs are largely failing to plan for a large portion of future renewable energy demand: the demand from large corporate buyers. This is a very fixable problem – it is time for RTOs to address corporate demand so that we have the 21st-Century infrastructure that Americans need and deserve.

In the past several years, U.S.-based corporations have been making major commitments to buy renewables and acting on those commitments. A coalition of more than 100 U.S.-based corporate entities called the Renewable Energy Buyers Alliance (REBA) has set a goal of purchasing 60 gigawatts (GWs) of renewable energy by the year 2025, equivalent to the amount of energy produced by 110 conventional power plants and enough electricity to power nearly 50 million homes. These corporations have already procured 9 GWs of renewable power, and as costs continue to decline for wind and solar, they are likely to accelerate this procurement.

Large companies are choosing long-term renewable energy contracts to power their operations both because their customers want clean energy and because of the cost saving and hedging benefits of renewables. New utility-scale wind and solar projects are now frequently the lowest-cost option for power – even before accounting for tax incentives – and companies are moving to lock in those low prices now to control their future energy costs.

→

FIGURE 1
NREL INTERCONNECTION SEAMS



To meet their goals, the REBA companies aim to procure an additional 51 GWs of renewables in just the next seven years. But they face a major challenge: there is a gap between where the country can produce the most cost-effective wind and solar resources and where electricity demand is projected to grow. The 15 states between the Rockies and the Mississippi River account for 88 percent of the country's wind technical potential and 56 percent of the country's utility-scale solar photovoltaic technical potential but are home to only 30 percent of projected 2050 electricity demand. Ensuring a reliable electricity system by connecting energy supply with demand is a core responsibility of transmission planners (see Table 1).

Our report shows that even if REBA companies attempt to procure only half the amount of renewables they have pledged to procure, they will likely face serious obstacles given the absence of attention to their renewable energy demand at the RTOs.

According to our research, only 52 GWs of capacity is available in the planned transmission lines that will access our nation's best renewable resources, even assuming all the planned projects are completed. Transmission capacity is needed, not just for the 51 GWs of REBA's voluntary corporate demand through 2025, but also to meet the mandatory demand from utilities implementing state-specific renewable portfolio standards as well as voluntary demand from utilities and other large institutional buyers such as universities and the military (see **Figure 1**).

Further analysis of ISO and RTO interconnection queues — which show the capacity of power generators seeking transmission interconnection — demonstrates that significant amounts of wind and solar are seeking access. In 2016, 150 GWs of wind and solar power capacity (equivalent to approximately 274 conventional power plants) entered interconnection queues compared to 40 GW of natural gas (equivalent to approximately 73 conventional power plants). Wind and solar comprised 78.9 percent of the total resources seeking access to transmission.

MISO and SPP experienced especially sizable additions in 2016. At the end of 2016, 142 GW of wind power capacity was seeking transmission interconnection in these RTOs — higher than all other generating sources.

In light of this demand, will the pipeline of planned transmission projects enable large corporate buyers to fully meet their goals? Our report finds that this result is very unlikely. →

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TABLE 1
TRANSMISSION LINE ACTIVITY SERVING RENEWABLE ENERGY PROJECTS

Transmission Project Name (State)	Voltage (kilovolts, KV)	Estimated In-service Date	Estimated Potential Wind Capacity (MW)[a]
MISO multi-Value Projects (ND, SD, IA,MN, WI, IL, MO, MI)	345, one 765 line	2015-2020	14,000
Grand Prairie Gateway (IL)	345	2017	1,000
Southline Transmission Project (NM, AZ)	345, 230	2018-2020	1,000
Power for the Plains (Nm, TX, OK)	115, 230, 345	2016-2020	1,230
Pawnee–Daniels Parks (CO)	345	2019	600
Gateway West (WY, ID)	500	2019-2021	3,000
Empire State Connector (NY)	320 DC	2020	1,000
Transwest Express (WY)	600 DC	2020	3,000
Sunzia (NM, AZ)	500	2020	3,000
Clean Line Projects (KS, OK, IA, NM, AZ)	600 DC	2020+	16,000
Southern Cross (TX)	500 DC	2021	2,000
SPP 2012 ITP10 Project (TX, OK, KS,MO)	345	2018-2022	3,500
Gateway South (WY, UT)	500	2020-2024	1,500
Boardman Hemingway (OR, ID)	500	2022	1,000
Total Potential New Transmission Capacity			**-52 GW**

Our report compared a high and low scenario for transmission construction with a high and low scenario for corporate renewable energy procurement, with RPS demand remaining the same across both scenarios. We found that only in a scenario with low corporate procurement (20 GWs or less) and an aggressive transmission build (90 percent or more of the planned projects completed by 2025), would there be potentially enough new capacity to meet corporate demand. Although we did not study the impact of retirements of existing plants, environmental regulations or others changes that might free up capacity in existing lines, we also did not account for voluntary procurement from utilities and other institutional buyers that are not members of REBA. Voluntary procurement by utilities is a particularly noteworthy trend, as new renewable projects are consistently bidding into utilities' requests for proposals as the lowest-cost option. Voluntary procurement by utilities and other non-REBA institutions could more than offset the freed-up capacity resulting from coal plant retirements and other changes to the generation mix.

Given these findings, two key actions are needed: (1) RTOs and other regional planners must begin accounting for corporate demand, and (2) corporate buyers must begin communicating their plans to transmission planners and advocating for their inclusion in models of future demand.

One way to implement the first recommendation is through strengthening the interregional planning processes and adding corporate procurement to the discussion. By improving these planning processes, FERC could help ensure that planned transmission development – both inter- and intraregional – is sufficient to meet corporate demand.

Also, while load forecasting is already an important part of regional planning, incorporating corporate energy demand for renewables into forecasts would be beneficial. One trend is particularly deserving of attention by modelers: big tech companies are choosing to site new data centers in areas with nearby renewable resources. These new facilities increase the load in that region, as was the case with the recently completed Facebook center in Fort Worth, Texas and Apple data center in Des Moines, Iowa.

In other cases, corporates are increasingly using virtual power purchase agreements (VPPAs) to procure renewables. A recent study of corporate wind PPAs by the American Wind Energy Association (AWEA) found that corporate customers were signing virtual PPAs rather than physical PPAs by a ratio of nearly 4:1. Although wind energy historically has been the preferred technology for corporate buyers, many companies recently have begun entering into solar PPAs as well, such as Apple, which has contracted 130 MW of solar through a PPA with First Solar.

And while VPPAs are purely financial transactions that do not require physical energy delivery or result in regional load changes, these deals are only possible if the transmission is already in place to facilitate their renewable purchase. In one recent example, featured as a case study in our report, the Hitchland-Woodward transmission line in the Oklahoma Panhandle allowed RES Americas to complete their Bluestem wind farm, the output of which was purchased by Google.

Perhaps more importantly, corporate customers prefer to invest in renewable energy projects that are located reasonably close to at least some of their energy demand, a practice known as co-location. Approximately 80 percent of the wind capacity bought by corporate customers through virtual PPAs is associated with wind projects located in the same electricity market where the corporate customer has at least some energy demand, according to AWEA.

This commitment to "buy local" is reflected in a statement from the 71 REBA companies that signed the "Corporate Renewable Energy Buyers' Principles," affirming that "where possible, we would like to procure renewable energy from projects near our operations and/or on the regional energy grids that supply our facilities, so our efforts benefit local economies and communities as well as enhance the resilience and security of the local grid."

Corporate buyers would play an important role in facilitating the growth of renewables by clarifying their locational goals in transmission planning processes. By communicating their energy goals to regional planners, corporate buyers can help ensure that renewable energy projects have the transmission capacity they need to become viable.

General Motors (GM) is an example of a REBA member that is becoming increasingly interested in transmission planning. A major wind power purchaser, GM sees the connection between adequate transmission and meeting their renewable goals. It recognizes that expanding and upgrading transmission will remain a key to unlocking the lowest-cost resources with the greatest carbon reduction potential well into the future.

"GM's ability to access renewable energy is key to our decisions about where to expand new facilities," said Rob Threlkeld, Global Manager of Renewable Energy, General Motors. "It's essential that transmission planners take the growing corporate demand for renewables into account in the planning process. Expanding and upgrading transmission is critical in helping GM access low-cost renewable energy and meet our commitments."

We see a unique opportunity for GM, and other companies like it, to have an enormously beneficial impact in our nation's future by helping ensure that the nation has the infrastructure it needs to transition to a clean energy economy. Likewise, the RTOs and other transmission planners can make a positive difference by acknowledging that the exciting trend of corporate procurement of renewables is here to stay.

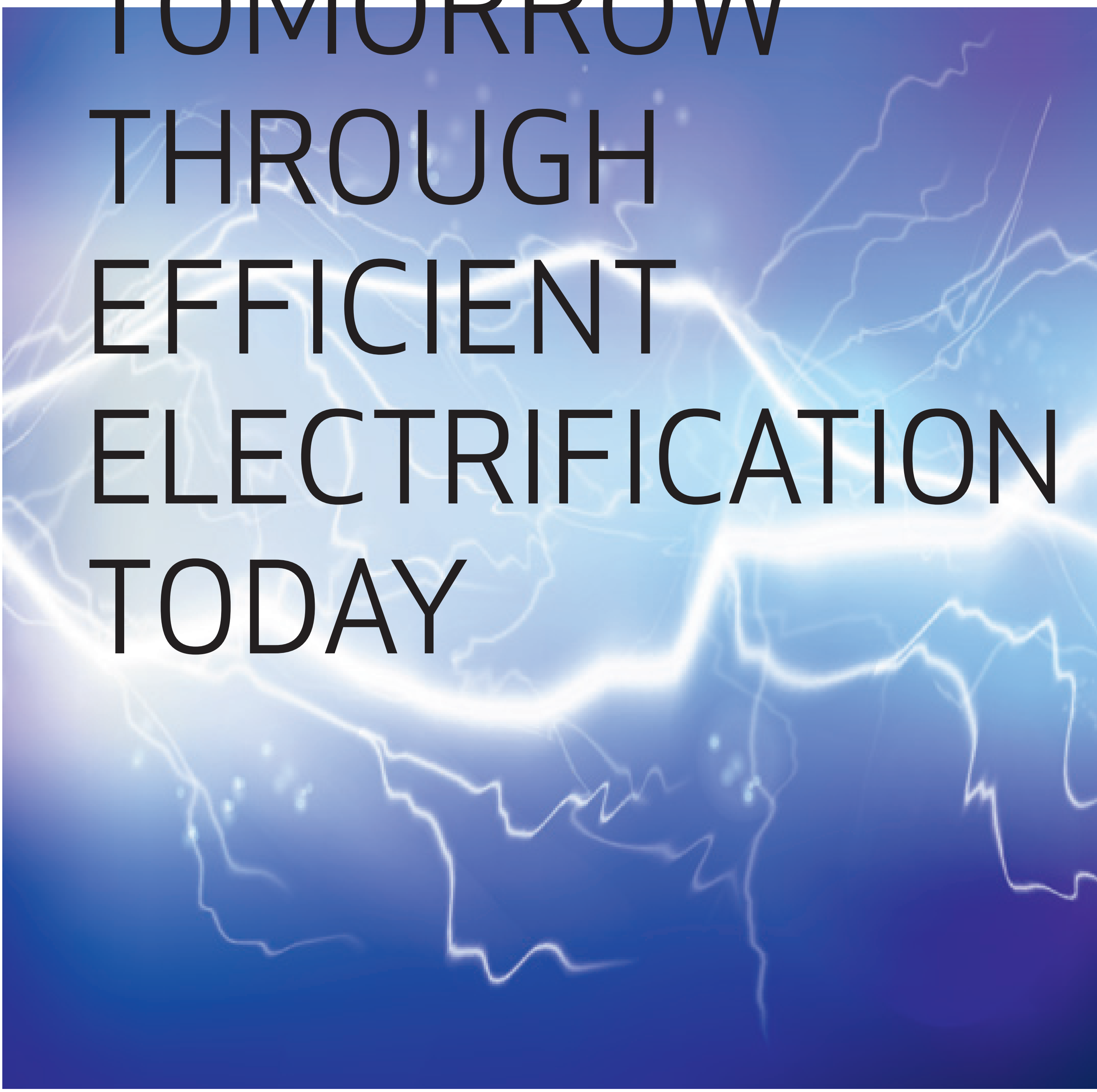
ABOUT THE AUTHORS:

John Kostyack is the executive director of the Wind Energy Foundation (WEF), where he leads WEF's work across the United States to educate decision makers, the media and the public about the economic, environmental, and national security benefits of renewable energy and the forward-looking energy and infrastructure policies needed to secure those benefits. Kostyack is an attorney with more than 30 years of leadership experience in government, the private sector and nonprofit organizations.

David Gardiner is the founder and president of David Gardiner Associates (DGA), a Washington DC-based sustainability consultancy that helps companies, foundations, and advocacy groups develop climate and energy programs and products that will lead to real change. Prior to founding DGA, Gardiner served as the executive director of the White House Climate Change Task Force during the Clinton Administration, the EPA's Assistant Administrator for Policy and the Legislative Director for the Sierra Club.

FROM RESEARCH TO ACTION

ELECTRIFYING TOMORROW THROUGH EFFICIENT ELECTRIFICATION TODAY



MARK MCGRANAGHAN

We are at the edge of a future that less than a generation ago was considered science fiction, and that future is enabled by electrification. As we move forward, local organic vegetables may soon be grown in a windowless room in the center of the city by use of highly efficient electric lighting. In a few years, self-driving, self-charging electric vehicles may communicate with other cars and trucks to enhance the efficiency and safety of transportation. Homes will be digitally programmed to automatically modulate energy use and temperature based on owner preferences.

These seemingly fictional innovations will need significant investment and advancements in broad-based electrification to come to fruition.

Further electrification could harness the benefits of a cleaner mix of electricity generation with advanced technologies to create more efficient applications for homes and businesses across key industries.

For more than 40 years, the Electric Power Research Institute (EPRI), an independent, not-for-profit research organization, has examined the long-term technical and reliability needs of the electric power system for the benefit of society. Last year, EPRI launched its Efficient Electrification Initiative, which will analyze the economic and societal benefits of electrification. The initiative will expand EPRI's research and development portfolio to explore new and existing electrification technologies including indoor agriculture, electric transportation, space conditioning and manufacturing.

As part of the initiative, EPRI will host the inaugural Electrification 2018 International Conference and Exposition August 20-23, 2018 in Long Beach, CA. This event will bring together commercial and industrial markets, R&D and academic communities, state and federal policymakers and other stakeholders to explore the benefits, policy, regulatory and environmental issues of electrification. →

Best practices for implementing efficient and cost-effective electrification programs and the latest electrification technologies will be showcased during this event. Participants will be able to form new partnerships and attend training sessions about the capabilities and impacts of current and future electric technologies.

In collaboration with the broader energy community, we are leveraging subject matter experts and EPRI's deep industry expertise and thought leadership to shape the future of an integrated energy network. Electrification 2018 will be the summer's key meeting for those looking to understand the benefits and costs associated with the adoption and use of electric technologies and solutions. There are six conference tracks that are featured in these conversations:

- **Electric Transportation** will focus on the merits, timing, costs, benefits and possible solutions for the electric vehicle market spanning future on- and off-road vehicles, high-power charging, smart charging, customer preferences, grid impact and challenges and lessons learned.
- **Industrial Electrification: Technologies and Implementation** will cover a range of current and emerging technologies and systems in agriculture, off-road transportation, and large and small commercial and industrial applications, highlighting the benefits and costs of electric technologies to energy stakeholders across industries for the public good.
- **Residential and Commercial Electrification** will examine the research and development of new electric technologies, such as space and water heating, which can provide great benefits, including lower costs and reduced environmental impact, to businesses and homes.
- **Understanding the Costs and Benefits of Electrification** will present the results of national studies on the potential benefits of electrification, assessments on electrification tailored to individual states and utilities and the impacts of electrification on water use and quality.
- **The Policy and Regulatory Landscape for Electrification** will focus on policy and regulatory challenges and opportunities as electrification progresses, including solving issues with the cost of electrification; the role of flexible, advanced electric loads in optimizing the power grid; how states are preparing for increased adoption of plug-in EVs and how electrification can enable the outcomes desired through advanced energy communities.
- **Breakthrough Technologies** will explore creative solutions that provide significant opportunity for every industry to improve processes including improved electric energy storage, electric vehicles, advanced nuclear generation, new models for wind and solar power generation, indoor agriculture, aerial drones and artificial intelligence.

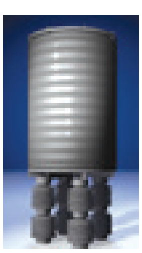
Efficient electrification has the power to transform the electric sector and the way we deliver and use cleaner energy, providing significant environmental, efficiency and customer benefits.

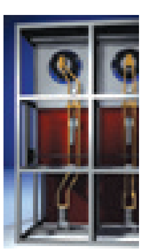
You can track our progress in the overall Efficient Electrification Initiative and sign up for our monthly newsletter at **https://www.epri.com/#/pages/sa/efficient electrification**. To learn more about Electrification 2018 or to register, visit **www.electrification2018.com**.

We invite you to join us and be part of the innovative conversations leading this evolving transformation.

ABOUT THE AUTHOR:

Mark McGranaghan is vice president of the Integrated Grid Sector for the Electric Power Research Institute (EPRI). He leads the teams responsible for EPRI's research involving technologies, systems and practices for the power distribution system and customer systems, as well as the related information, communication and cyber security infrastructure and systems. McGranaghan has been with EPRI since 2003 and has had a strong influence on EPRI's research in the areas of power quality, advanced distribution systems and the smart grid. He has worked closely with government and industry research organizations, both in the United States and around the world. Prior to joining EPRI, McGranaghan was with Electrotek Concepts (1998-2003) and McGraw-Edison/Cooper Power. McGranaghan has BSEE and MSEE degrees from the University of Toledo and an MBA from the University of Pittsburgh. He has taught seminars and workshops around the world and is very active in standards development and industry activities. He is an IEEE Fellow.





HOW ELECTRIC UTILITIES WILL DRIVE SMART CITY ADOPTION

KEITH TEICHMANN

The worldwide smart cities market is expected to pass the $1 trillion mark in 2019 to eventually reach $3.48 trillion by 2026. Ignited by advances in information technology, communications and the expansion of the Internet of Things (IoT), this explosive growth for the smart cities market is opening the doors to incredible opportunities for municipalities – connecting and streamlining everything from street lights to traffic lights, police reporting and more.

In one example of smart city advancement, San Diego, California and Jacksonville, Florida are trialing new technologies that use LED street lighting to collect and analyze data. Every lamppost in these cities will become an active part of a city-wide information network, capturing and relaying data in real time about what's going on around it. More recently, at the Consumer Electronics Show (CES), the City of Las Vegas unveiled its latest focus on safety and security in its Innovation District through the use of smart street lights that monitor air quality, traffic and pedestrian congestion.

While the opportunities are endless and go beyond these two examples, municipal government leaders simply cannot expect to create a smart city alone. To realize their smarty city vision, these leaders need to focus on collaborating and communicating across all organizations and groups – including private companies, private citizens and, in particular, utilities.

In fact, in a recent survey of 644 utility, municipal, commercial and community stakeholders across the U.S., respondents indicated that smart city initiatives are expected to be driven primarily by electric utility (23 percent) and transit (24 percent) opportunities. What's more, nearly 43 percent of respondents selected utilities as the top driver for their smart city collaboration efforts.

So, why are utilities so critical to smart city adoption and how can they accelerate the growth of smart cities for our more intelligent future? →

How Utilities are Leading the Charge

By 2020, the number of connected devices is expected to reach 24 billion and the number of mobile-connected devices will reach 12 billion. This growing number of devices and digital applications provides cities with huge opportunities – but also poses a challenge for municipalities from a data perspective.

Smart cities rely on the processing of large amounts of data typically collected by sensors, such as in intelligent street lighting. For example, the city of Amsterdam uses more than 170 data-driven applications to shape their policies on public transit, public safety and energy use. This data collection enables municipal leaders to make more informed decisions about providing critical services to their public, but typically they struggle to manage, analyze and also maintain the security of this staggering amount of data they are collecting on a daily basis.

That's where utilities come in. Utilities are adopting new solutions to modernize the grid and provide a more stable and reliable communications network that leverages analytics, while also providing an accessible wireless, scalable, secure and mesh-enabled environment. Not only are these solutions allowing for the seamless integration of Wi-Fi enabled products that are critical to smart city operations but they allow for the improved collection and analysis of data in real-time – and that goes beyond utilities' smart meters and energy usage data.

Because utility assets are deployed throughout a city and have relationships with the majority of homes or business owners, they are integral to driving the transformation of a city into a smart city. With advanced technologies and analytics connected to the grid, sensors can be attached to anything to collect and analyze more data – from traffic lights to street lights, buildings and beyond.

Collaboration Between Cities and Utilities

Utilities have essential assets and infrastructure that make their participation in the smart city push crucial for the success of those communities. As such, utilities have a real opportunity to take ownership as potential partners with municipality leaders to accelerate the growth of smart cities.

In one example, San Diego Gas & Electric (SDG&E) joined the Smart City San Diego initiative, a collaboration across public, private and academic organizations to improve the city's economic development, ramp up energy independence, encourage consumers to use electric vehicles (EVs) and reduce greenhouse gas (GHG) emissions. Their first step was in installing residential smart meters to produce real-time data around energy use

In another example, the city of Pittsburgh formed a collaboration to tackle its aged-out energy infrastructure issues together with Duquesne Light Company (DLC), NRG Energy and Siemens, as well as local universities, businesses and non-profits. Their smart city initiative aims to create a series of microgrids that connect energy generation, transportation and communications across multiple stakeholders in the community.

When it comes to making cities smarter, electric utilities and community leaders are overcoming similar challenges while oftentimes working toward the same goals.

A Resilient Smart City Future

As the demand for smart city innovation grows, cities are looking to outside insights and resources to help chart their course. Collaborating with utilities is critical to their success and, in doing so, municipalities will be well on their way to achieving their smart city goals and ensuring a more resilient future for their communities.

ABOUT THE AUTHOR:

Keith Teichmann has won three of the world's most recognized industrial design awards. He holds three international patents and is currently the Chief Technology Officer at Delta Energy & Communications, Inc. With more than a quarter-century of experience, Teichmann combines a strong technical background with strategic business acumen to deliver highly differentiated value propositions through logical, results-oriented executions. Prior to joining Delta, he was the director of innovative networks and marketing at Xylem's Applied Water Systems growth center. Teichmann received his B.S. in mechanical engineering from Purdue University, his M.S. in mechanical engineering from Rensselaer Polytechnic Institute and his M.S. in management from the Krannert Graduate School of Management at Purdue University. He is a graduate of ITT's Ashridge Strategic Management Program and is a certified Value Based Six Sigma Green Belt.

POWER TRANSFORMER RELIABILITY

– IT DOESN'T JUST HAPPEN

TONY MCGRAIL

Introduction

Power transformers are large capital items with long lead times for production; they are critical to our electric infrastructure, and their reliability is an important subject for analysis. Reliability, however, doesn't just '"happen" – it is a consequence of specifying and buying a well-built transformer and ensuring careful shipment to site, proper installation and subsequent life management. These technical activities and processes are included in an overall asset management program, which balances cost, risk and performance. Reliable in-service transformers are the result of more than just "data" and statistics; there needs to be action planned and intervention performed to address reliability issues at the source.

What, exactly, is meant by the term "reliability" is open to interpretation, but it usually is based on an ability to predict future performance. If we wish to use reliability as an indicator of an ability to perform a role consistently well, it may require intervention so that deteriorating performance can be addressed. As is well known, maintenance as an intervention can also lead to future unreliability.

Figure 1: Large Power Transformer

Reliability may be measured in electric supply system terms such as System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI), which look at the average duration and frequency of system interruptions, or outages. These can be very useful statistics, but do not necessarily identify the interventions required to improve reliability. For power transformers, we can simplify the matter by relating reliability to failure: what do we need to do to keep a power transformer operating at acceptable performance levels? There are many possible causes of failure, and hence, many possible causes of unreliability. Addressing these causes before they develop into a problem is crucial to driving acceptable performance and reliability. Calculating the probability of failure of an individual transformer, or the expected number of failures for a population in a given timeframe, is a complex matter – but improving the reliability can be addressed through proper life management.

In the following sections, we will look at examples from different stages of a power transformer's lifetime, where something caused an unplanned unavailability of a power transformer and required intervention over and above that which was specified or planned for that power transformer. →

Initial Specification and Design Review

Is the power transformer we need something well understood and for a well-defined purpose? Given that we have been making power transformers for well over a hundred years, the answer to the question would seem to be yes. But there are times when reusing a previous specification can lead to future performance issues. The increased failure rate of wind farm transformers, as compared to the more common transmission and distribution power transformers, was discussed by Ayers and Dickinson [1] in a 2011 paper where they noted:

"It has been recognized that wind farm step-up transformers are a unique application and demand their own special requirements, both in Europe and the United States."

Variable loading with consequent thermal cycling, multiple harmonics, high levels of harmonic distortion and non-sinusoidal loads, meant that in the authors' words:

"These cumulative effects put the wind turbine step-up transformer at a higher risk of insulation and dielectric stress and failure than either the typical 'off the shelf' distribution transformer or the power generator step-up transformer experiences."

Thus, problems can be built in at the design of the power transformer if the role, future working environment and operating parameters are not specified and addressed in detail. Corsi *et al.* [2] note that a design review is vital and usually performed at the manufacturer's facility to address any specific issues:

"Ensuring that a good quality product is manufactured and delivered successfully is difficult, and the process should begin early in the procurement process by the proper selection of the manufacturer and by establishing the suitability of the proposed transformer design."

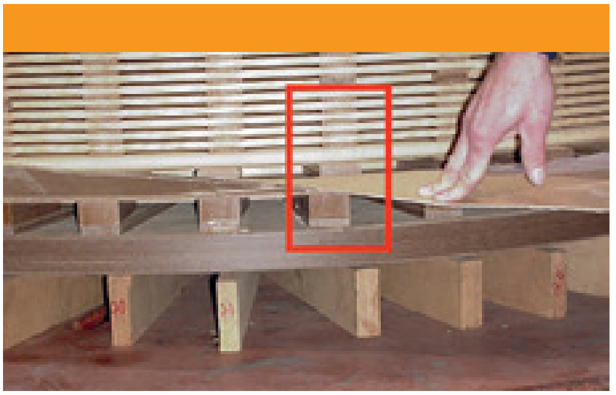


***Figure 2:** Coil Block Misalignment Found During Pre-Tanking Inspection*

Factory Inspection and Test

Factory inspections are used to demonstrate that the production of a power transformer is in compliance with technical specifications and applicable industry standards, and to assess the overall quality of the transformer. Factory tests are an integral part of the production process – performed on the various sub-components individually and together as the transformer is built.

Pre-tanking inspections are not common but can identify a variety of issues. Prout [3], in a presentation at the Doble "Life of a Transformer Seminar," gives several examples of issues found during inspection activities which could have seriously reduced the power transformer's performance. In addition, an in-service failure for a transformer could be traced to coil blocking misalignment – something which would allow the transformer to pass factory tests but would weaken the transformer's ability to withstand mechanical stresses. An example of such coil blocking misalignment is shown in **Figure 2.**

For one manufacturer, only 10 percent of customers performed a pre-tank inspection of their own [3], which is disappointing as issues can be addressed much more easily at this stage when proper steps are taken.

Factory testing is well understood, and most purchasers will either witness this testing themselves, or they will send a third party to perform this function on their behalf. It is important to understand the test method and the test object so that results can be compared to expectations and to standard or permissible limits. One commonly required test is sweep frequency response analysis (SFRA), which is used to detect and, possibly, diagnose mechanical movement, such as winding deformation, in power transformers. Performing SFRA is a common element of factory acceptance tests. SFRA is often performed with the transformer in shipping configuration, just before shipment, so that further tests may be performed on arrival. In a case reported by Leal [4], SFRA was performed with a transformer in shipping configuration with unexpected results.

The pre-shipping SFRA traces showed significant variation, both with respect to the previous traces from the factory acceptance tests and between phases. If these tests had not been performed at the factory, the transformer status on arrival would be drawn into question, and possibly cause a return to the manufacturer – which would be an issue for both customer and maker. As it was, a set of winding leads had been displaced and were addressed before shipment, with subsequent SFRA tests meeting expectation before the transformer left the factory.

Figure 3: Lead Support Beams with Cracked Laminations

Transport and Installation

The data from the SFRA was used to solve a problem, which may have been attributed to transportation issue

As discussed by Griesacker et al. [5] at the International Conference of Doble Clients, this situation can also be addressed through visual inspection. In the case mentioned, a transformer had suffered a series of low-level impacts, none greater than 3.0g, as a result of rail transport. Inspection showed several issues, including coil block movement and lamination buckling. **Figure 3** shows a crack in the laminated insulation of a lead support beam, which is likely to weaken the beam and mean that the probability of transformer failure due to lead movement, under fault or energization inrush currents, is increased. The reliability of the transformer is likely reduced and through multiple such small variations, the overall dependability of the grid could be at risk.The paper [5] notes:

"The utility's initiative to follow up on this seemingly small impact event has probably prevented a failure and subsequent unscheduled outage, considering the true condition of the transformer that was uncovered during internal inspections. The conservative approach and thoroughness in investigating the transformer condition while under pressure to meet project deadlines proved to be invaluable."

It may have been a conservative approach, but the need to identify and address condition and possible performance issues early, before they lead to reliability issues, is clear.

Insurance Views

In a round-table discussion of insurance company views of transformers, asset management and condition monitoring, attended by HSB Insurance, Aegis and other companies, it was noted that "… part of the pricing … is actually based on how well they believe you manage assets."

Maintenance is both a means to address condition and performance issues and through poor maintenance practices, is itself a cause of failure and unreliability. Both Marsh and HSB have presented discussions of transformer failures at Doble's "Life of a Transformer" seminar, which indicate the role of poor maintenance as a catalyst for advanced failure. Don Schubert of Marsh Insurance stresses "mode of failure, time to failure." Maintenance may take place at intervals of several years to more than a decade, and failure modes may be substantially less than this duration. Annual dissolved gas analysis (DGA) of transformer oil may indicate incipient failure modes, but not always. In addition, some components, such as bushings, may have failure modes, which are not identifiable through regular DGA or testing. In such cases, condition monitoring may be of value.

Condition Monitoring

There is an interesting statistic quoted by Don Schubert, which states that companies that apply condition monitoring have 3 percent lower insurance payouts required in comparison to those that do not apply the approach. This does not mean that an organization that applies condition monitoring will automatically see a consequential reduction in claims and payouts. Successful application of condition monitoring is an aspect of an organization with strong asset management; it is embedded in the culture of the organization rather than something added to it.

Condition monitoring will bring value in terms of improving reliability if we apply the three C's:

- **Control** the measurement being made and what it implies for failure modes that apply, and the timescales under which they operate; plan response
- Understand the **context** of the measurement and whether there is a relationship with load or temperature
- Come to a reasonable **conclusion** and act upon it

Condition monitoring has shown that it can avoid incipient failures, including identifying issues with bushings, tap changers and windings. **Figure 4** shows the leakage current magnitude, taken hourly, from three bushings of a type known to have a higher than average failure rate – one of over 100 sets monitored. →

FIGURE 4

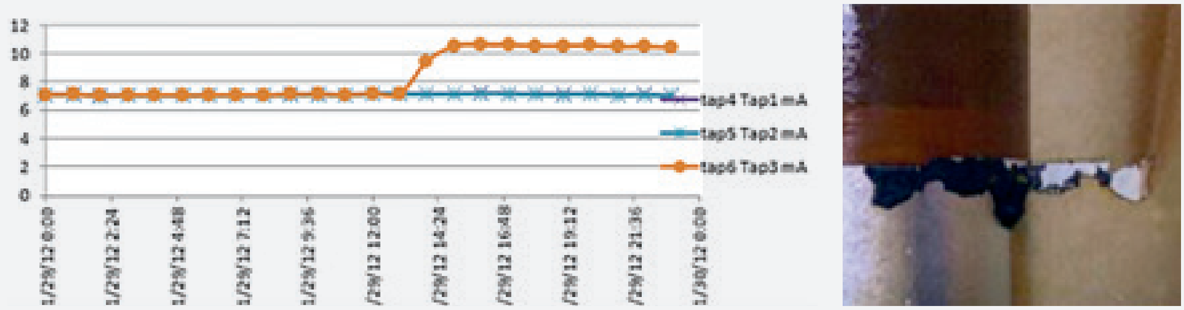


Figure 4: *Leakage Current Magnitude and Related Bushing Deterioration – Incipient Failure Prevented*

The sudden change generated a top-level alert, which was acted upon by the bushing owner and operators – in fact, the response was the subject of a written policy, requiring the removal of the transformer from service within two minutes. It is this formal approach that prevented the failure and reliability issue– having a plan, and then acting upon the plan. A forensic tear down showed advanced deterioration within the bushing insulation, with just a few hours left before a bushing failure and likely catastrophic transformer failure. It was estimated that the cost of the avoided interruption was of the order of US $10M. The cost of the monitoring, in comparison to the cost of the power transformer, is small, but in comparison to the cost of the interruption, the monitoring cost is minuscule.

A sudden change in hydrogen levels, though not breaking any standards or guidelines, generated a rate-of-change alert and an investigation ensued. Gas levels were low – too low to trigger several of the diagnostic tools available – but the gases indicated the onset of a high-temperature thermal fault. This was traced to a loose tap changer lead, which was addressed in a timely manner.

In the cases described, condition monitoring provides value in managing reliability, but in both cases, and in many others, that value is only realized through the setting of appropriate alert levels, having a planned and timed intervention to those alerts, and then carrying out that intervention in a timely manner.

Asset Health and Risk: Managing Reliability

There has been a growth of interest in the concept of "asset health" and the related activity of giving assets a "health index" for ranking and categorizing assets for replacement, maintenance and other interventions. Asset health is inextricably linked to asset performance, and in consequence, to asset reliability.

Generating a single number to represent the health of a complex asset with multiple sub-components is not a simple task or one that can be carried out without a very clear purpose in mind – including tracing the process through data available, failure modes identified, and timescales for interventions/actions. This process can help improve reliability if the method is technically justifiable and auditable – too many systems start with data, use a set of algorithms and then produce a number that may have no actual meaning. Using a regular automobile as an analogy, we would probably not plan for a new car just because the tire pressure is low; there may be far better means to address the situation.

It must be noted that the asset health index approach is a means to identify intervention candidates, and is not "the answer": there must be confirmation and supporting data through a detailed assessment. This requires an analysis of the business need: is the power transformer planned for replacement based on capacity requirements – in which case, can we leave it until that plan occurs? If the failure mode is likely to be non-catastrophic, can we let the transformer fail – and prepare by bringing up a spare and having everything ready? This becomes a risk analysis – looking at the transformer failure as a hazard to reliability and managing the condition and the consequence.

Conclusion

To ensure reliable performance, we need to consider all aspects of a transformers life and the "experiences" it has had. Reliability doesn't just happen, and the consequence of poor life management at the outset, or during operational life, can impact reliability significantly. It is well understood that the operational phase of a power transformer's life — when it is installed, carries load and is maintained — is the largest part of the overall life. The possible impacts of maintenance and deterioration in service are also generally well understood, but the life of a transformer is affected from day one of the needs assessment and the specification and design review process. Everything that occurs before the transformer is delivered and commissioned can affect the resultant operation, and must not be ignored.

Reliability doesn't just happen.

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ABOUT THE AUTHOR:

Tony McGrail is Doble Engineering Company's solutions director for asset management & monitoring technology, providing condition, criticality and risk analysis for utility companies. Previously, McGrail spent more than 10 years with National Grid in the UK and the U.S.; he has been a substation equipment specialist, with a focus on power transformers, circuit breakers and integrated condition monitoring and has also taken on the role of substation asset manager and distribution asset manager, identifying risks and opportunities for investment in an ageing infrastructure. McGrail is a Fellow of the IET, a member of the IEEE and the IAM, is currently chair of the Doble Client Committee on Asset and Maintenance Management and a contributor to SFRA and other standards at IEEE, IEC and CIGRE. His initial degree was in physics, supplemented by an M.S. and a Ph.D. in EE and an MBA. McGrail is an adjunct professor at Worcester Polytechnic Institute, MA, leading courses in power systems analysis.

FLEXIBILITY MANAGEMENT PLATFORMS:

THE KEY TO GREATER RENEWABLES AND DER INTEGRATION

SHANE O'QUINN

It used to be simpler to balance loads and resources. Back in the heyday of centralized generation and one-way flows, you drew from the available stack of generating resources to plan for forecasted demand and to meet real-time loads.

Not anymore.

As older, less-efficient fossil-fuel and nuclear units retire, low natural gas prices and favorable costs for renewables are making them the prime sources of new generating capacity. Renewables generation will double between 2017 and 2050, the Energy Information Administration projects. Meanwhile, customers are adding behind-the-meter resources such as solar and storage. And myriad of software-enabled systems is allowing two-way power flows, turning consumers into producers. Global distributed energy resource (DER) capacity is projected to grow from 132.4 GW in 2017 to 528.4 GW in 2026, according to a marketing research company specializing in the energy industry.

The changes are pushing the need for more flexible resources on the electrical grid. As the California Energy Commission noted in its December 2016 report on resource flexibility: "Maintaining the reliability of the electricity system while integrating larger amounts of variable wind and solar generation requires more flexible resources to balance supply and demand."

While grid designers build transmission and distribution systems to handle the changing nature of loads, the injection of variable renewable generating resources into the grid creates new challenges for utilities and system operators. In response, utilities are deploying a variety of operational and technical solutions to help manage the influx of intermittent and distributed energy resources. The solutions include improved weather forecasting, flexible generation, storage, intra- and inter-regional load balancing and faster scheduling and dispatch. Additionally, the growth of smart-grid enabled devices such as networked thermostats, water heaters, HVAC systems, electric vehicles, stationary batteries and industrial loads provides utilities with numerous opportunities to control demand while maintaining power quality.

All this added flexibility is great. But utilities need to manage this flexibility somehow. This is where the concept of flexibility management comes into play. →

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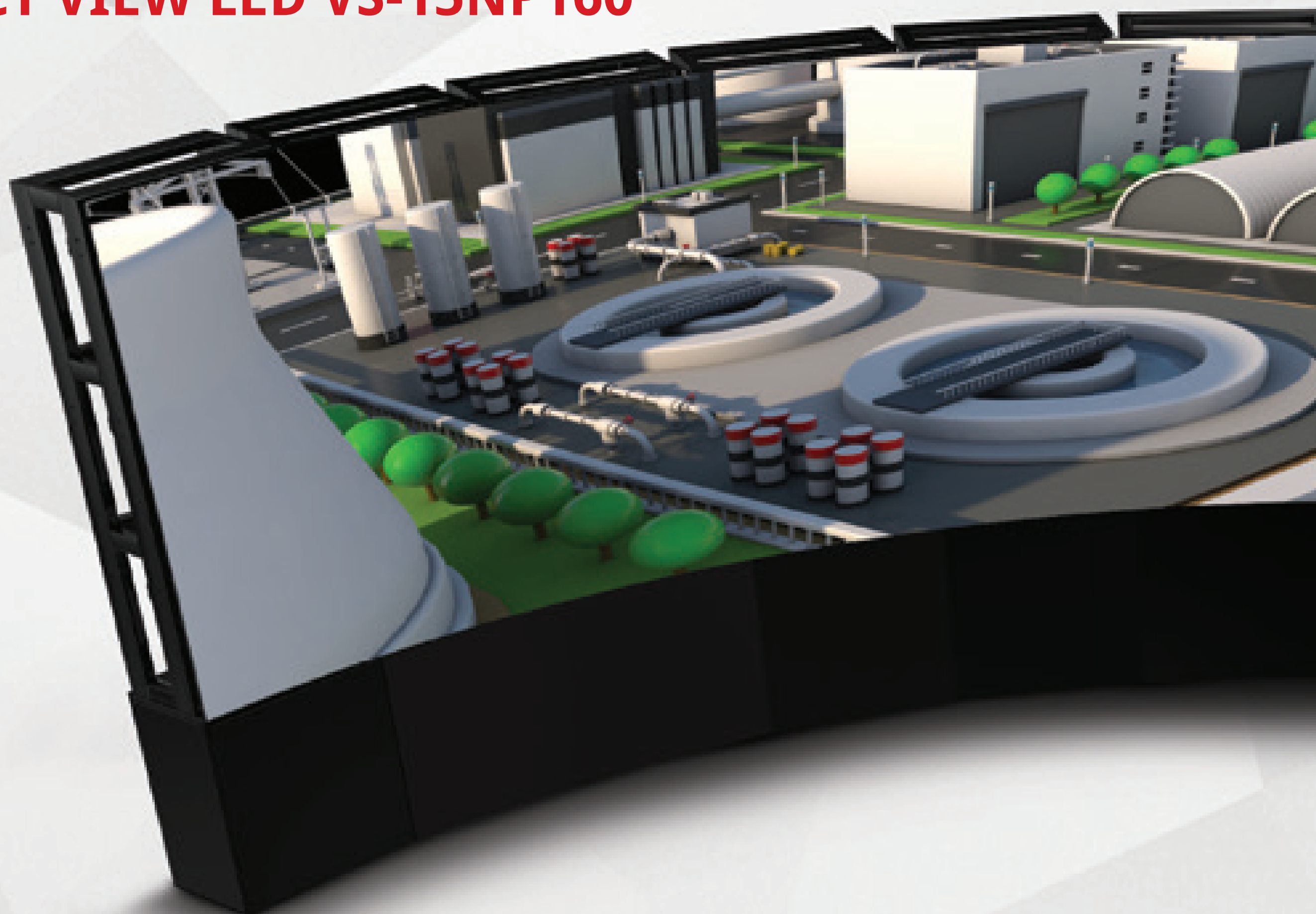

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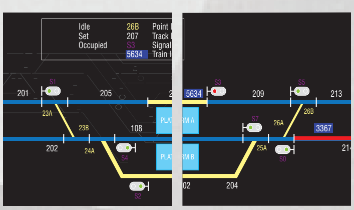

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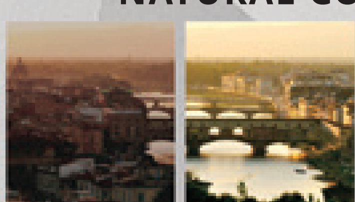

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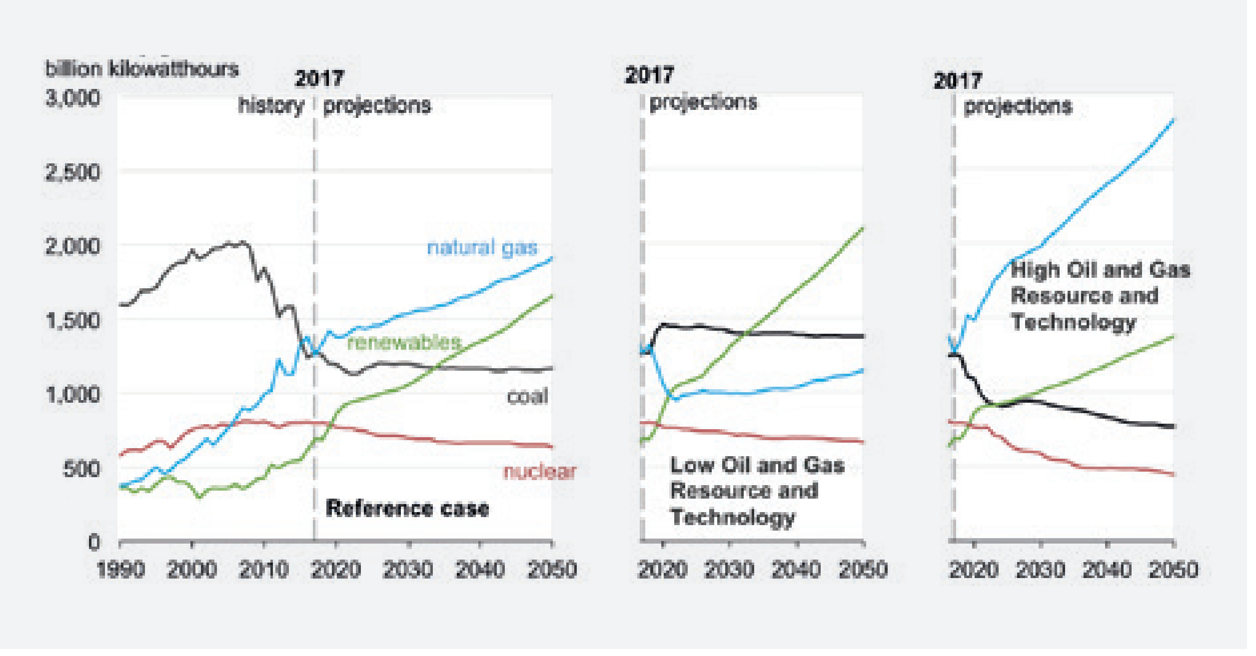


Generation from natural gas has already bypassed coal and nuclear and renewables are not far behind. (Source: U.S. Energy Information Administration, Annual Energy Outlook 2018.)

Flexibility Management: A New Source of Operational Extensibility

Resources that can ramp down during off-peak hours and ramp up during on-peak hours provide operational flexibility. These include flexible hydro, natural gas-fired combined-cycle and combustion turbine units and large, centralized battery storage. But perhaps the most interesting and important new source of operational flexibility comes from utilizing data and the software systems that do something meaningful with this data. This concept is being called the energy internet by some in the industry.

Hosting both energy and data flows, the energy internet opens up data from millions of interconnected DERs and sensors, which new software applications then harness to deliver flexibility to energy providers. These software solutions allow utilities to balance supply and demand in a real-time, granular fashion, in order to maximize the value of the new distributed, dynamic and digital energy network and to meet their environmental mandates. This delicate balancing act is a requirement for greater deployment of renewable generation, both large scale and behind the meter, in order to consider these resources as firm assets, which the utility can count upon when needed.

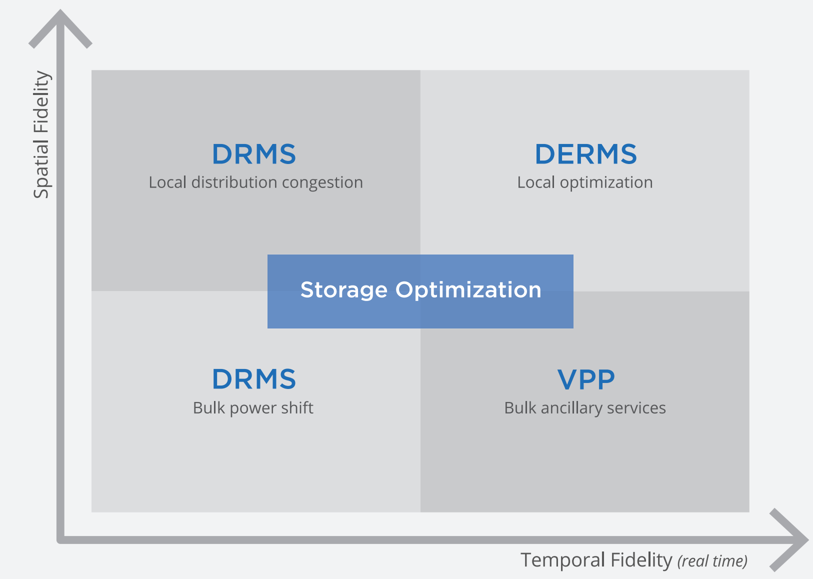
The introduction of software into the business of load balancing is undisputed as the future of energy distribution. The problem facing grid operators, however, is how to choose from among an array of potential options. Many of the options are point solutions, dealing with a limited number of use cases, asset types or customer categories.

A Universal Platform for DER Integration

The truth is, nobody knows which hardware or software technologies will succeed and which ones will fizzle out. But point solutions make utilities bet on which technologies will win in the future. Universally adaptable software platforms, on the other hand, take an open approach, meaning that on top of being able to predict, optimize and control all types of DER assets in real time and at scale, they also allow for a constant evolution of their hardware network.

This means that the utility or utility's customer can buy one type of solar panel today, switch providers next year and not have to worry about the compatibility of its orchestration system. Same with batteries and all other types of Internet of Things devices that end up grid connected. Regardless of the technology of the day, a universally open platform allows for the ultimate amount of flexibility. Additionally, as one type of hardware is added for one software customer, those integrations become available to all, creating a network effect that benefits all customers.

DER INTEGRATION



Flexibility management software applications allow utilities to integrate DERs across a range of times and locations.

With flexibility management software, utilities can manage and optimize the following resources in real time, across the entire connected energy network:

- All distributed energy resources and assets
- All programs
- All customer types
- Millions of participants
- Millions of assets
- Billions of data points

In a world where both supply and demand are unpredictable and potentially out of the utility's control, the key to balance is harnessing data to flex with the subsequent ebb and flow of energy. Flexibility management software leverages artificial intelligence and big data to balance supply and demand in real time, increase the productivity of every energy asset and deliver new energy services and value to customers.

Balancing Across Time and Space

Balancing loads and resources requires decisions to be made across the dimensions of time and space. Utilities and grid operators must simultaneously work at the macro and micro levels when it comes to the spatial dimension—from 500-kilovolt transmission lines down to neighborhood distribution feeders. And they must work in a variety of time increments, from seasonal, to day-ahead, on down to hours, minutes, seconds and real-time dispatch decisions.

A flexibility management platform allows utilities to integrate DERs across spatial and temporal ranges.

As illustrated in the graphic on DER integration, an integrated flexibility management application can treat flexibility use cases and asset categories in all four quadrants of a time-location graph:

- Bulk power shift (bottom left quadrant). At the bulk-power-system level, a emand response management system (DRMS) would enable the aggregation of DERs at scale for services such as load shifting and peak shaving. This DRMS application would enable utilities to increase the amount of generation that can be connected to the system without deteriorating the grid's performance.
- Bulk ancillary services (lower right quadrant). Traditionally, operators use regulating generation to "chase the ACE," or Area Control Error, which is the instantaneous difference between the scheduled and actual interchange. But a fleet of real-time DERs could do the same thing. To resolve immediate balancing needs, an ideal virtual power plant (VPP) application would aggregate myriad DERs into a virtual flexible resource that could be controlled and monetized in energy markets in

real-time to provide ancillary services such as → frequency regulation, contingency and operating reserves and other ramping services. This would extract maximum value from assets, create new revenue streams and increase flexible capacity.

- Local distribution congestion (top left quadrant). In a local, less time-constrained scenario, the ideal DRMS would deliver comprehensive, dispatch-grade demand-response management down to the level of a single distribution feeder. This application would provide bankable load shed forecasts, increase customer participation rates and improve program yield, taking into account potential future asset and program requirement changes more traditional DERMS..

- Local optimization (top right quadrant). A DERMS application would provide the broadest solution to connect and manage any type of DER, from any vendor. Utilities could do surgical dispatch, at a micro-grid level, on distribution equipment and provide ancillary services such as volt/VAR optimization.

- Behind-the-meter (BTM) optimization (center). DER flexibility management platforms also offer optimization of BTM assets. Today, more customers own battery assets that help them reduce demand charges or provide backup power. But these usages leave unexploited value on t he table. Using an energy storage management system (ESMS) application, utilities could partner with their customers by purchasing access to their storage assets. The utility would aggregate customer DERs to shift system peaks, perform frequency regulation, acquire reserve response, or increase hosting capacity as a distribution resource. In turn, customers would acquire an extra revenue stream from the sale of capacity into wholesale markets.

Managing Flexibility to Integrate Renewables and DERs

As variable renewable energy increases its penetration of the grid, utilities need greater flexibility to balance loads and resources. Traditional baseload generation facilities, with their relatively slow ramp rates, high minimum generation limits and long, costly startup and shutdown processes, lack sufficient reliability at a needed level of cost in order to provide the required flexibility.

More efficient and operationally flexible distributed and renewable energy resources, combined with a flexibility management software platform to manage them, offer utilities the opportunity to design a reliable and lower-cost supply network to meet modern system, regulatory and market needs. With greater flexibility, planners and operators can integrate greater levels of variable renewables and DERs while meeting their mission of providing reliable energy in a cost-effective manner, deepening their relationships with customers as they provide greater value.

ABOUT THE AUTHOR:

Shane O'Quinn is the senior director for strategic accounts at AutoGrid Systems. Prior to AutoGrid, O'Quinn was vice president of business development for Enbala Power Networks and spent 14 years at Ventyx (now part of ABB). Before entering the energy sector, he worked in management consulting and software firms including Ernst & Young.

MODELING THE GRID FOR DE-CENTRALIZED ENERGY:

HOW PROPER MANAGEMENT OF DER INTEGRATION WILL ALLEVIATE PRESSURE ON THE GRID

MICHAEL SCHNEIDER AND VONNIE SMITH

Utilities are facing massive changes that affect all aspects of their business, from planning through operations. Once an industry characterized as technology-risk averse, utilities have been shifting to more agile approaches with a higher tolerance for risk. Modeling the grid to accommodate these changes requires new approaches and closer relationships with trusted technology partners. This paper will examine what methodologies have driven the acceleration of grid decentralization and what technologies still need to be applied for smooth integration and success.

Certain Trends Have Led to an Overworked Grid

Growth in generation at the grid edge, also referred to as distributed energy resources (DER), has inarguably reached critical mass. Approximately 75 percent of survey respondents in a recent report indicated that DERs will be somewhat or significantly more important in the next 12 to 24 months. Industry newsletters are also reporting about the implementation of renewable generation projects almost daily.

Although T&D networks with centralized generation sources have traditionally been modeled using GIS and other network management capabilities, managing assets over the complete lifecycle is a foundational component of modeling for a de-centralized grid. As DER supplements or even replaces coal and nuclear generation, the management of utility assets becomes a larger issue: there are more assets to manage and maintain and reliability and predictability become more challenging.

Regulation uncertainty will continue as regulators who share the same technology issues as utilities, struggle with how to represent to their constituencies. It is difficult to answer questions about which approaches to incentivize and how to balance consumer issues with using utilities to recover costs, especially when renewable sources, such as rooftop photo voltaic (PV), clouds the definition of customer and supplier. How these considerations will affect the underlying asset model is not clear as different regulatory models are being tested.

Aging assets remain a lingering problem. Replacing assets, notably transmission and generation assets that are operating well past their design life, have been delayed due to the uncertainty around cost recovery, shifting environmental policies and uncertainty over replacement choices. While utilities grapple with replacement issues, managing aging assets increases the importance of full documentation of an assets' operational history to understand and support predictive and preventative maintenance.

Investment deficit has been a problem in the past that must be addressed in emerging economies to support societal and economic growth. This means rapid development of infrastructure and greenfield design of projects that incorporate DER and renewable energy sources from the beginning. →

Cyber threats are growing as rogue states target utilities for offensive tactical advantage and criminals attempt to hijack and hold systems for ransom. Whether or not an asset's vulnerability to cyber-attack is a component of its criticality attribute or something that needs to be separately managed is a question that has not yet been answered.

The effects of these trends are far-reaching and include reinforcing existing policies and practices while forcing utilities to move outside their traditional comfort zones to try new approaches.

Common Connectivity: The Pathway to Adaptation

Utility systems must adapt to share information and interact. Managing assets is an area where interoperability is crucial and federating information through a connected data environment (CDE) must be part of the solution. The Internet of Things (IoT) has already become a key part of many industries, such as process control. IoT has extended into utility devices like smart meters and increasing DER into the grid drives the need for the digitalization of information. "Smart" instrumentation and control devices produce a substantial amount of data, and much of it is important to understanding asset health. Existing and evolving standards such as IEC 61968 (information exchange), IEC 61850 (configuration of intelligent devices), IEC 30141 (IoT reference model) and ISO 55000 (asset management) all work to provide a standards-based architecture to facilitate exchange of information between utility systems to strengthen and improve the benefits of the CDE.

A utility's baseload is increasingly being covered by renewable energy sources. Renewable generation goals are being met ahead of schedule with some reports of 100 percent renewable generation now considered possible, according to EUCI. Consisting of wind, solar and more, renewable energy resources are being integrated with storage technology to improve the availability of power despite the variability of winds and sunlight, further driving the change to a de-centralized grid and systems that manage the grid. Utilities network models must change to meet those challenges.

Distributed energy sources have different operating models than traditional generation, such as coal-fired generation, nuclear and gas. As a foundation for simulation and predictive analysis, utilities systems are expanding their capabilities to include support for DER.

Due to the nature of DERs, utilities are not always able to control how or when these resources are connected. Organizations are implementing microgrids to meet their own requirements for high availability rather than relying on the utility. Houston Health Systems is a topical example, as their gas-fired microgrid kept them in operation during Hurricane Harvey. Network feeders that serve customers with their own microgrid will likely have different criticality assessments than identical network feeders with customers who have no backup. Asset models must be flexible to accommodate these types of differences, especially when taking provider-of-last-resort scenarios into consideration.

Digitalization of the Operation

Network management systems have become more sophisticated, enabling data tracking, advanced decision support and operational analytics. Using high volumes of digital data from many devices and integrating information technologies (IT) and operational technologies (OT) with engineering systems provides the basis to create a digital view of a utility. Combined with reality data from laser scans and high-resolution photography, this "digital twin" utilizes powerful capabilities for reliability analysis and design optimization. These capabilities are critical whether in response to unplanned external events or the need to evaluate design options for future system changes in both greenfield and brownfield situations.

As DERs grow in usage, the grid is concurrently becoming more populated with sensing and actuating devices as part of the process of digitalization. Gartner's website states, "[digitalization] is the use of digital technologies to change a business model and provide new revenue and value-producing opportunities; it is the process of moving to a digital business." A digital representation of the grid is visible at its fullest extension. This digital representation will provide massive volumes of data that can be used to better understand grid performance currently, previously and potentially in the future.

By combining algorithms and simulation capabilities with the digital representation, a "digital twin" is created. As a concept, digital twins have been around for a long time, but the IoT has ensured that the implementation of a digital twin is now cost-effective.

Big data must contain an information model that documents the grid assets and maintains their status at any point in time. Asset lifecycle management documents when and where the asset was installed, its maintenance and service record, as well as other key information required for comprehensive asset stewardship.

Speaking a Common Language

To make digitalization worthwhile, systems must be able to share information effectively and seamlessly. Therefore, systems should interoperate through a connected data environment. Reliability analysis, compliance and safety reporting and operational analytics are core functions needed for asset stewardship, and they involve multiple database components and systems. Through enterprise interoperability, based on industry standards, data can be available whenever and wherever it is needed.

The IEC Common Information Model (CIM) is important to interoperability. CIM derives from the standards for distribution, transmission and energy markets. Based on work begun by the Electric Power Research Institute (EPRI) and continued by the IEC, CIM provides a common language for communication between utility systems within the industry and with external entities, such as an independent system operator (ISO) for electric transmission.

Proprietary interfaces that have been standardized and made public are just as important for interoperability because they are able to export and import data from other systems and are transparent. In a network reliability study, network models from a geographic information system (GIS), combined with asset lifecycle information, were used by a planning engineer to examine poor performing, unreliable networks and improve network maintenance. Furthermore, this approach can improve network modeling by determining where new DER will be most effective or considering the integration of privately-owned DER. Interoperability with the connected data environment can help identify optimum grid connection points. With thousands of DER, the grid will constantly be changing and only an integrated digital infrastructure will be able to design, operate and maintain the many assets that compose it.

Connected Data Environment is Critical for Efficient Management of DER

Using asset lifecycle information to plan an asset's reliability bolsters the value of network data because it is relied on from the engineering design phase to the analysis domain. This use of asset lifecycle information also demonstrates why interoperability with the connected data environment is critical for efficient management of a de-centralized grid. In this instance, a set of engineering analysis capabilities will utilize asset lifecycle information combined with GIS data and data internal to the engineering capability.

A utility will have regulatory and related internal standards for network design, including operating criteria, load conditions, failure modes and digital catalogs of approved construction components (called compatible units or CUs) that define and guide how planning and design are performed and what parts are usable. Without a connected data environment, implementation and management of the many interfaces become challenging IT problems when facing a de-centralized grid. Making decisions about adding DERs to the grid based on factors like expected network performance, reliability and power quality is difficult if not impossible.

Simulation uses digitalization to model the current grid or show the grid with proposed grid changes, such as a DER connection request, where simulation can accelerate and improve the assessment of a DER interconnection request.

After identifying a connection point, the analyst needs to understand how the new DER will affect the network. For instance, the analyst must know if the connection will cause current and/or voltage to exceed limits or short circuit limits. In order to have all questions answered, a model of the DER is connected to a digital representation of the network and algorithms are applied to simulate network operation under varied conditions. The simulation is run in the design phase to ensure the DER will not cause network operation outside defined limits for variables like power/load flow, voltage limits, harmonics, frequency response and more.

Predictive analytics is another capability that is essential in a network model that supports DER. The goal of predictive analysis is to find problems before they occur at a reasonable cost. The historical and real-time data available through a connected data environment can make seeing trends and understanding anomalies difficult without the necessary capabilities to track, analyze and report important events, especially in a de-centralized grid populated with large numbers of DERs and even more IoT devices. An event can be something as simple as an unexpected change in frequency, or it can be as subtle as micro-cracks in a solar panel that impact system voltage. Analytics can provide perspectives of the event that help determine whether a change is a symptom or a cause, thus determining where corrective action needs to be applied.

According to Michael Schneider, general manager and global head of Siemens Power Technologies International, "Electric utilities today have a growing need for planning and analysis solutions that tackle the fluctuations of decentralized renewable generation. →

That means good forecasting, state-of-the-art models and the ability to study many scenarios per year. Enabling these outcomes requires a highly dynamic mode of analysis where network models are continuously up-to-date. It also helps utilities and industrial owner-operators address the challenges of planning, designing and operating integrated DER networks in a highly efficient manner."

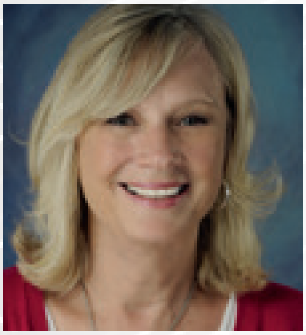
Conclusion

As utilities face huge changes and work to adjust all aspects of their business with the integration of DERs, agile approaches to technology and information management will help them achieve their goals. To embrace the digitalization process, leaders need to emphasize the importance of the connected data environment, the need for integrated engineering and analysis and the value of predictive analytics. In addition, new approaches to network modeling must be adopted to handle the new world of distributed generation. As costs reduce and DERs grow in popularity, it is important to the grid that DER integration and not just connection is carried out smoothly and reliably to the benefit of the utility and the customer. Incorporating DERs into the digital twin is one way of easing them into the grid right at the design phase to ensure all possible problems are brought to light before implementation. Once implemented, DERs can be monitored in the same manner as the rest of the grid in order to assess reliability and performance. Then, DERs become truly beneficial because they ease the burden of the central grid.

ABOUT THE AUTHORS:

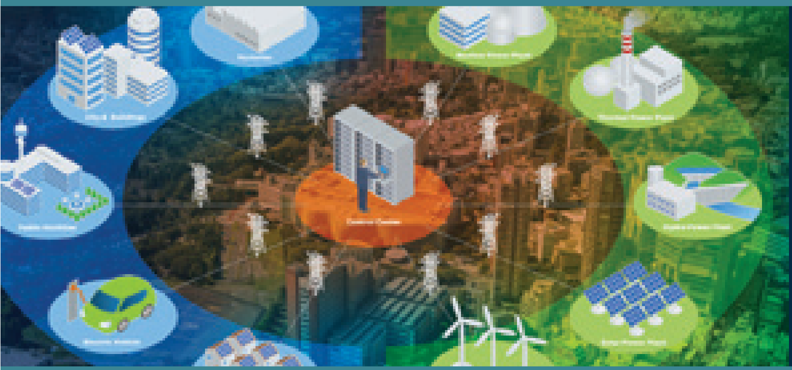
Michael Schneider is head of Siemens Power Technologies International (Siemens PTI), a group of 400 leading experts in power system consulting and grid planning software located in nearly 30 regional Siemens offices around the world. He has been actively driving Siemens Digitalization approach for a true "digital grid" and has been strongly involved in developing lifecycle solutions for improved operational efficiency, system stability and increased grid resiliency. Making use of increasingly available data combined with strong domain knowledge in designing and operating energy infrastructure has been his key focus, bridging previous separate domains like grid analysis, operations and asset management.

Before joining PTI, Schneider held the global responsibility for strategy in the Siemens Divisions Energy Management and Smart Grid. Prior to that he spent nine years with Siemens Management Consulting, focusing on the areas of software and automation business strategy, business transformation, infrastructure and sustainability. Schneider studied business & engineering at the University of Stuttgart and obtained his MBA from the University of Massachusetts Dartmouth.



Vonnie Smith is vice president of utilities asset performance at Bentley. She joined Bentley in 2005 and has worked in leadership capacities related to asset performance, geographic information system (GIS), utilities and communications. Prior to joining Bentley, Smith was president and CEO of Cook-Hurlbert, having served in that capacity for over 20 years. During her tenure at Cook-Hurlbert, she focused corporate strategy and initiatives toward the company's mission of providing software to the electric, gas, and water utilities industry. Cook-Hurlbert was subsequently acquired by Bentley, and the company's landmark product, Expert Designer, became the basis for Bentley's OpenUtilities range of products. Smith has a Bachelor of Science in electrical engineering from the University of Texas at Austin, with a specialization in electric power systems.

MODELING THE GRID FOR STREAMLINED RENEWABLES INTEGRATION



CHALLENGE

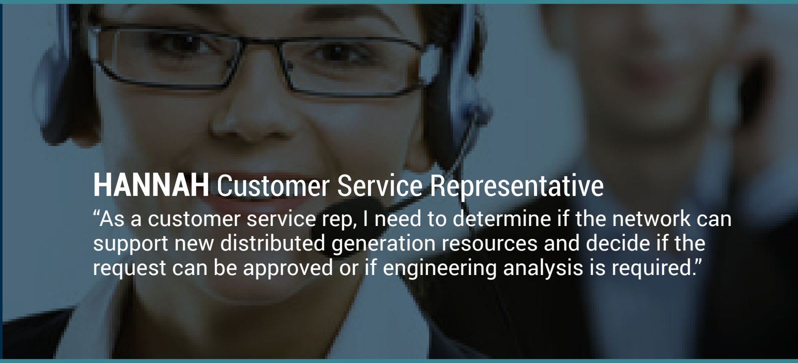
Today's power grids are rapidly evolving to include traditional and distributed energy resources, which present new challenges and increase **reliability** and **resiliency** requirements.

NEED

Evaluate impacts and understand potential problems.

SOLUTION

Use an always available and **up-to-date network model.**



HANNAH Customer Service Representative

"As a customer service rep, I need to determine if the network can support new distributed generation resources and decide if the request can be approved or if engineering analysis is required."

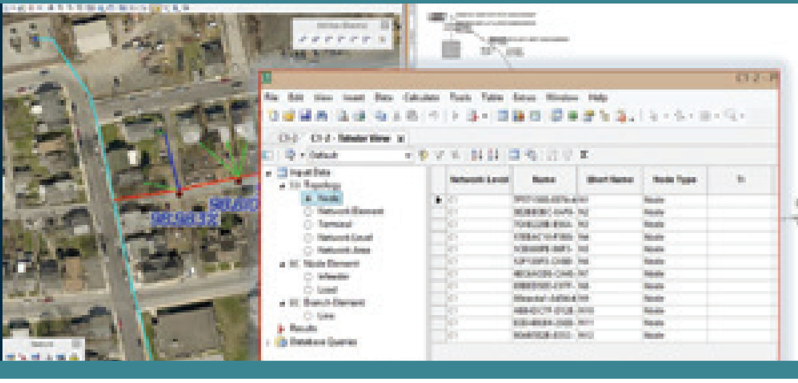
BENEFITS

- Better decision making and analysis
- Many requests can be approved without engineering analysis
- Requests that require further study are easily identified
- Respond quickly to customers and stakeholders
- Avoid harmful conditions
- Reduce costs

A MODEL DESIGNED FOR *YOU*

Avoid mistakes associated with conflicting, inaccurate, or obsolete data sources.

Accurate simulations provide guidance on grid performance.



OpenUtilities provides increased options for utilities who are facing increasing pressure to reduce costs, improve reliability, and build in resilience in response to changing global markets.

Bentley® *Advancing* Infrastructure

MICROGRID EVOLUTION FUELS MORE INTELLIGENT POWER

DELIVERING ON RELIABILITY, EFFICIENCY AND COST SAVINGS

WILLIAM MURCH AND BRUCE G. CAMPBELL

With increased capacity of solar, wind, energy storage, combined heat and power (CHP) and other distributed energy resources (DER), there is an opportunity to optimize energy to support resiliency to critical areas. And, as technology and material costs for solar PV and energy storage have improved, it is now possible to generate reliable energy to improve grid resiliency at competitive market pricing levels.

Over the last decade, microgrids have become an increasingly compelling means to not only keep the power on, but to manage distributed energy resources and energy costs. According to GTM Research, the trends driving microgrid growth include:

- Energy resiliency requirements stemming from extreme weather/power outage events
- New business models for microgrid ownership that involve multiple stakeholders
- Technology innovations enabling strategic energy management
- Opportunity for microgrids that support commercial and industrial customers

In the Beginning: Department of Energy, Utility Project is the First of its Kind

In October of 2012, a 5 MW / 1.25 MWh energy storage system was completed as part of a broader U.S. Department of Energy Smart Grid Demonstration project in Salem, Oregon. This early energy storage system was integrated with an existing distribution feeder and utility-dispatched distributed generation to form a high-reliability zone. The system was an industry-first; using lithium-ion battery technology in a large, utility-scale application that could operate connected to the traditional utility supply or as an island in voltage forming mode, allowing the generation on the feeder to connect to it.

When connected to the substation, through intelligent power management, the energy storage system can store or release energy depending on energy market conditions to optimize lower cost generation resources. The system can also prioritize renewable generation over fossil fuel plants, ensuring that the utility makes the best use of renewable energy that is already available. →

FIGURE 1

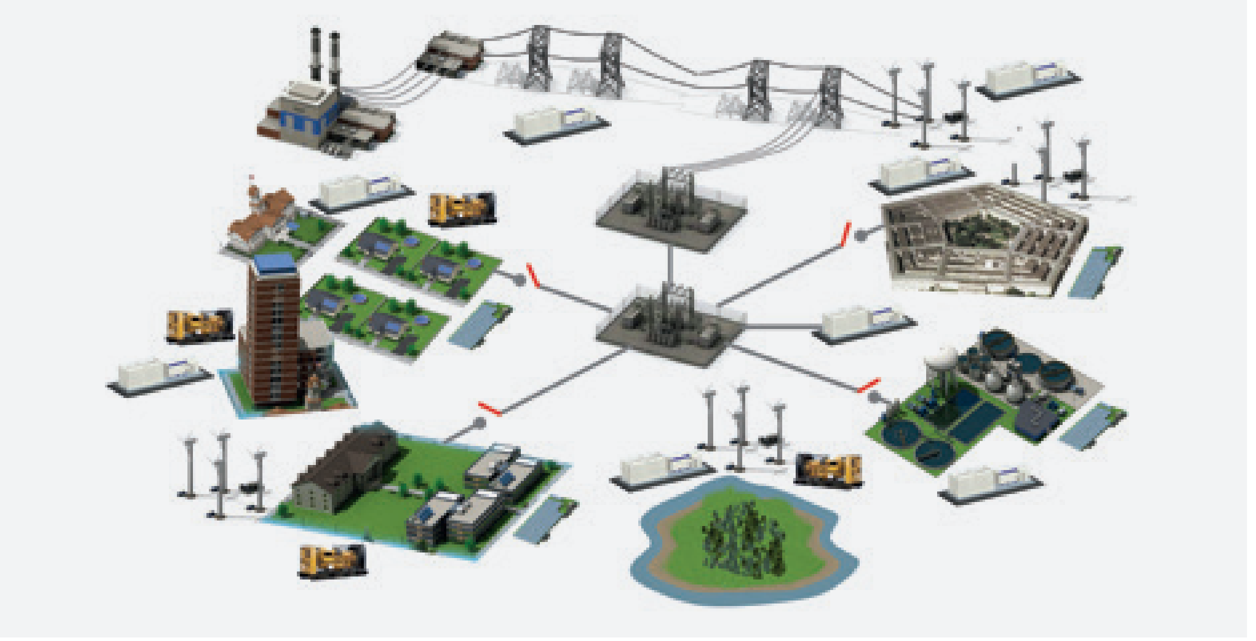


Figure 1. *Microgrids must be able to operate in parallel with the grid and as standalone electrical power systems that consist of multiple generating assets and often storage sources supplying loads, which can be powered independently of the primary utility transmission and distribution grid. (Image courtesy of Eaton.)*

The integrated control system operates the energy storage system in a variety of modes by interfacing with inverters, power meters, battery management system and the utility's upstream system controls. This closed-loop control system coordinates the operation of the inverters and balances states of charge among the 40 battery blocks. In the event of an upstream outage, the control system, combined with custom inverter programming, provides seamless support for loads—keeping the power on for commercial and residential customers served by the feeder. The system also allows the operator to request that the batteries be equalized in charge and enables the storage system to respond to real and reactive power commands from the utility, helping the utility test its smart-grid control algorithms.

The intelligent energy storage system along with the dispatchable generators create a high-reliability feeder that can detect faults and island the medium-voltage feeder — helping to improve service reliability. Inside of the high-reliability zone, a 2.5-mile smart feeder system provides reliable power for residential, commercial and light industrial customers. Additionally, the energy storage system has sufficient capacity to support the microgrid for several minutes, creating a backup power supply in case of an interruption.

Five years ago, the system was at the forefront of smart grid technologies — helping to build the intelligent distributed energy resources of today while continuing to deliver value to the utility's customers. Today, the utility continues to add more features to the energy storage system.

Early Microgrids: Defense Initiatives Advance Technology and Demonstrate Capability

Energy resiliency and security is a critical concern for the Department of Defense (DoD), which needs to operate regardless of electric grid outages from cyber-attack, natural disaster, aging or lacking infrastructure, or equipment failure. The DoD is also responsible for most of the U.S. government fuel consumption and is one of the largest single consumers of energy in the world.

As such, it has a vested interest in ensuring energy resilience, reducing consumption and controlling costs and has pursued a variety of initiatives to reduce fuel needs and change the mix of resources that it uses.

The DoD recognized a shortage of demonstrated large-scale microgrids that would support its interests in energy security, reducing fuel cost, resupplying convoy casualties and increasing renewable energy capacity. In 2013, a full-scale demonstration project at Fort Sill in

Figure 2. *Intelligent Mobile Power Distribution System. (Image courtesy of Eaton)*

Oklahoma showed that such a system could work off of the grid and balance the use of solar, wind and natural gas backup power and store energy for later use.

The project was part of the DoD's effort to better reduce costs and increase reliability. The microgrid extended the smart grid to integrate renewable resources and optimize fuel mix, energy storage and system operations to reduce cost, carbon footprint and the system architecture—maximizing reliability and uptime.

The key innovation in this project involved adapting a conventional control system for monitoring and control of a microgrid with generators and inverters, instead of developing a system controller and monitoring from scratch. The project built on microgrid control technology to improve the level of maturity and demonstrate a full-scale DoD microgrid.

The Fort Sill microgrid provides valuable experience for seamless transitions between grid-connected and islanded operation and experience with a high concentration of dynamic and nonlinear loads. As microgrids are retrofitted into existing systems with a high penetration of dynamic loads, the Fort Sill microgrid demonstrated the ability to provide energy resilience by operating during grid outages, seamlessly transitioning between grid-connected and islanded operation, and integrated renewables and energy storage.

Microgrids on the Move

Military success and security in combat situations depend, in part, on safe and reliable access to fuel, which can come with a high price tag. Considering the price of fuel for forward operating bases, or the actual cost of buying, moving and protecting a gallon of petroleum, the costs of supplying battlefield generators with fuel has increased dramatically. This dependence and the threat it faces in forward operating bases led the U.S. Army to seek both energy alternatives and resource management strategies.

An intelligent mobile power distribution system (IMPDS) was developed in 2014 and is a reliable, energy-efficient system to help manage generator output. By transforming an independently operating system of generators into a demand managed microgrid, This intelligent mobile power distribution system provides power only where and when it is needed and can help limit the risks that troops face as they use, transport and store fuel.

The system supports resiliency by providing adequate power to meet current energy demands, instead of inefficiently engaging all the generators continuously, which can reduce energy waste. Further, the system also uses intelligent load management technology to prevent grid collapse in the event of a generator fault. →

If one generator were to fail, the IMPDS prevents a stoppage of energy flow by shifting demand onto the supporting generators, thereby providing a constant, safe supply of power.

The U.S. Army's military installation at Fort Devens, Massachusetts demonstrated that the demand-managed microgrid significantly outperformed the traditional approach that relies on multiple independent generators. This system reduced fuel consumption by more than 30 percent.

Enabling Technology

These and other successful early deployments helped advance and innovate on technology that is enabling new applications and driving value from microgrid systems. The control architecture is one of the most important elements of a microgrid system—it provides the brains behind the operation. In most current designs, the microgrid is tied to the upstream grid via a point of interconnection (POI) and is managed by local control of assets, which enables faster, semi-autonomous or autonomous control of the microgrid devices to better maintain operation within connected equipment limits.

Today, integrated, modular, distributed control architecture is becoming a reality. Using lessons learned from early projects, new technology that is pre-engineered, factory-designed and tested provides a replicable model that is designed for further customization to site-specific requirements. This approach can simplify microgrid projects that use a variety of renewable or distributed energy resources plus storage, making it easier to test the system and support forward compatibility as the system evolves. The easy configuration of the controller helps maximize the flexibility and scalability of the system while reducing engineering cost.

When looking for a controller, functionality should coordinate automated system sequencing in response to user commands, system status, limits or faults. Additional control functions could also include active control, data logging, alarm management and processing, as well as built-in security measures.

Industry Trends: The Move to a More Distributed Energy Model

It is more than a matter of the technology for microgrids and distributed energy resources being available. The costs to generate and store energy are decreasing, which is changing the nature of the utility grid from a centralized generation model to a distributed system of sources and loads. The electric system architecture is a system that allows consumers, especially consumers of large amounts of energy, to generate, store and manage energy usage. In effect, power generation is moving

FIGURE 3

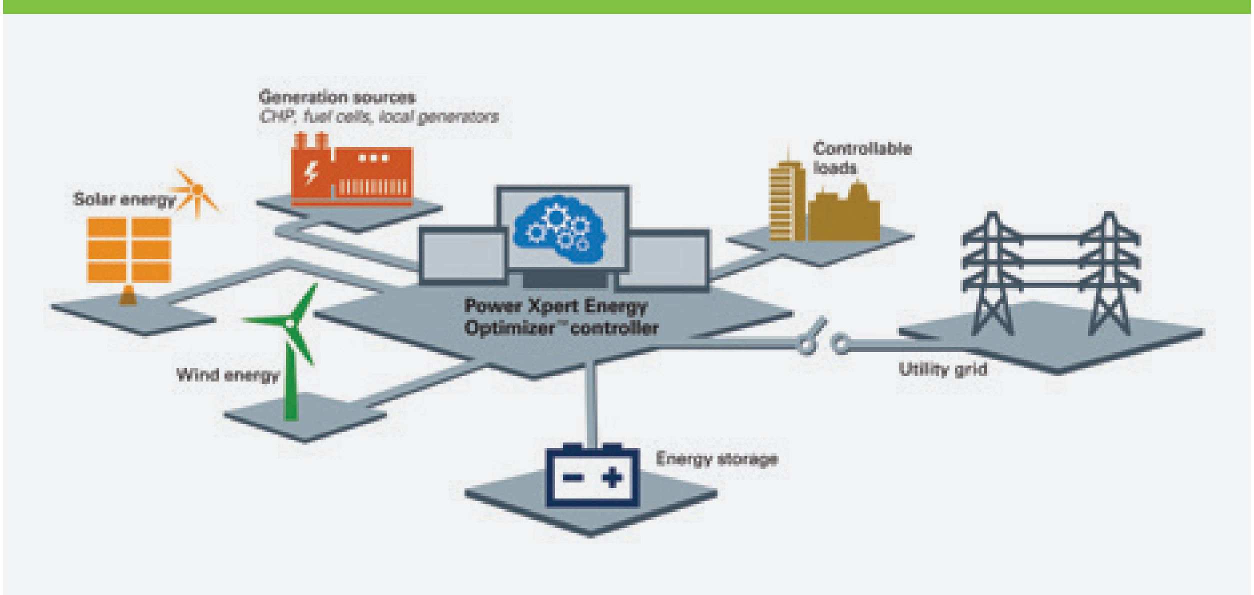


Figure 3. *Microgrid energy system (Image courtesy of Eaton.)*

closer to the user due to the availability of microgrid system technology that can be leveraged with multiple types of renewable or distributed generation as well as the lower cost of energy storage.

Solar Capacity Dramatically Increases, While Costs Decline

As the installed costs for solar PV projects have rapidly declined in recent years, more solar PV has been installed in the United States. The year 2016 was another record-breaker; the U.S. market added 14,762 MWdc of solar PV, just about doubling the capacity installed in 2015 and adding (on average) a new megawatt of solar PV capacity every 36 minutes. 2016 was also the first year that solar was the top source of new electric generating capacity brought online, making up 39 percent of added capacity.

As the number of installations increase, equipment prices have decreased; utility-scale system prices have fallen below $1 per watt for the first time according to GTM Research and the Solar Energy Industries Association (SEIA) reports. Today, enough solar energy is generated to power 8.7 million homes. And, analysts anticipate the industry will more than double installed solar capacity in the U.S. over the next five years, surpassing 100 GW.

Transformation: Combined Heat and Power (CHP) Systems

CHP is an efficient approach to generating electrical power — capturing heat that would be wasted to provide thermal energy that can be used for heating, cooling, hot water and industrial processes. CHP helps reduce energy costs, increase efficiency, reduce greenhouse gas emissions and support energy resiliency. And while this clean energy solution has been around for a century, it is underutilized and poised for growth according to a 2016 Department of Energy (DOE) report.

CHP can scale and be used in large industrial complexes, commercial building, institutions, municipal facilities and residential applications. DOE reports estimate that there is more than 240 GW of technical potential for CHP, largely in commercial facilities. The technical potential reflects an "estimation of market size constrained only by technological limits," and it cites multiple trends driving growth, including lower costs and ability to support resiliency, utility interest and project replicability.

Energy Storage Predicted to Experience Explosive Growth

Nearly five years ago, a mere 0.34 GW of energy storage could be found globally. Fast-forward to today, and the market expects 6 GW of energy storage to be installed in 2017 alone.

Most of these deployments will be as utility-scale projects, while residential and non-residential projects are also showing significant growth. It is important to note that with the increased penetration of renewable energy resources, utilities are seeking to optimize these renewable assets to reduce grid impact and enhance stability—the sweet spot for energy storage.

Microgrid Drivers Today

The drivers for microgrid systems have evolved and the technology is being used by a broader mix of industries and applications. Installing a microgrid is no longer limited to science projects and forward operating military bases. Microgrids can now be easily applied to facilities that already have solar, storage or other on-site generation sources.

For example, a power management company's Experience Center includes a full-scale operational microgrid, located in Warrendale, PA. The microgrid provides power continuity for utility grid interruptions and peak demand management, as well as a live platform for demonstrations and testing.The system, which was installed in 2017, takes advantage of solar PV and a natural gas generator, as well as recently added energy storage to power the lighting, HVAC and house loads for a large part of the facility. The system intelligently manages on-site energy resources and the utility supply to provide peak shaving, PV smoothing and shifting, demand management seamless islanding and reconnecting to grid power and grid-connected power factor.

As our electric grid becomes more complex, it is increasingly important that it is smarter, more reliable, allows for bi- and multi-directional transmission, and is responsive to the fluctuating consumption habits of businesses, residents and emerging community needs. This smarter grid will enable better control of energy costs, reductions in energy requirements, more effective support of sustainability initiatives and improved power reliability. →

Optimization Through the Lens of Experience and Technological Innovation

If microgrid projects continue to meet analyst estimates, we will be relying more on stored and renewable energy. As projects increase, it is important to consider supplier expertise, experience, business stability and success with prior projects.

Proven power engineering, substation automation and control experience are essential. Suppliers should also be able to provide rapid, dedicated, local support to help expedite projects, as well as on-the-ground expertise to address unforeseen challenges.

Solution providers should also be able to provide more than the right controller. Because every project carries unique circumstances, look for a supplier who understands the challenges of not only a microgrid energy system but also a power system and can plan for individual project's needs today and in the future.

Every application for a community, business or military base is unique, and customized solutions can help optimize, build and maintain an automated, secure and cost-effective renewable energy and storage project. A supplier's past projects can be indicative of the depth of solutions experience. Often, those who offer an "end-to-end" solution, including design, procurement and installation, can help you achieve your renewable energy and storage goals in less time and at a lower installed cost.

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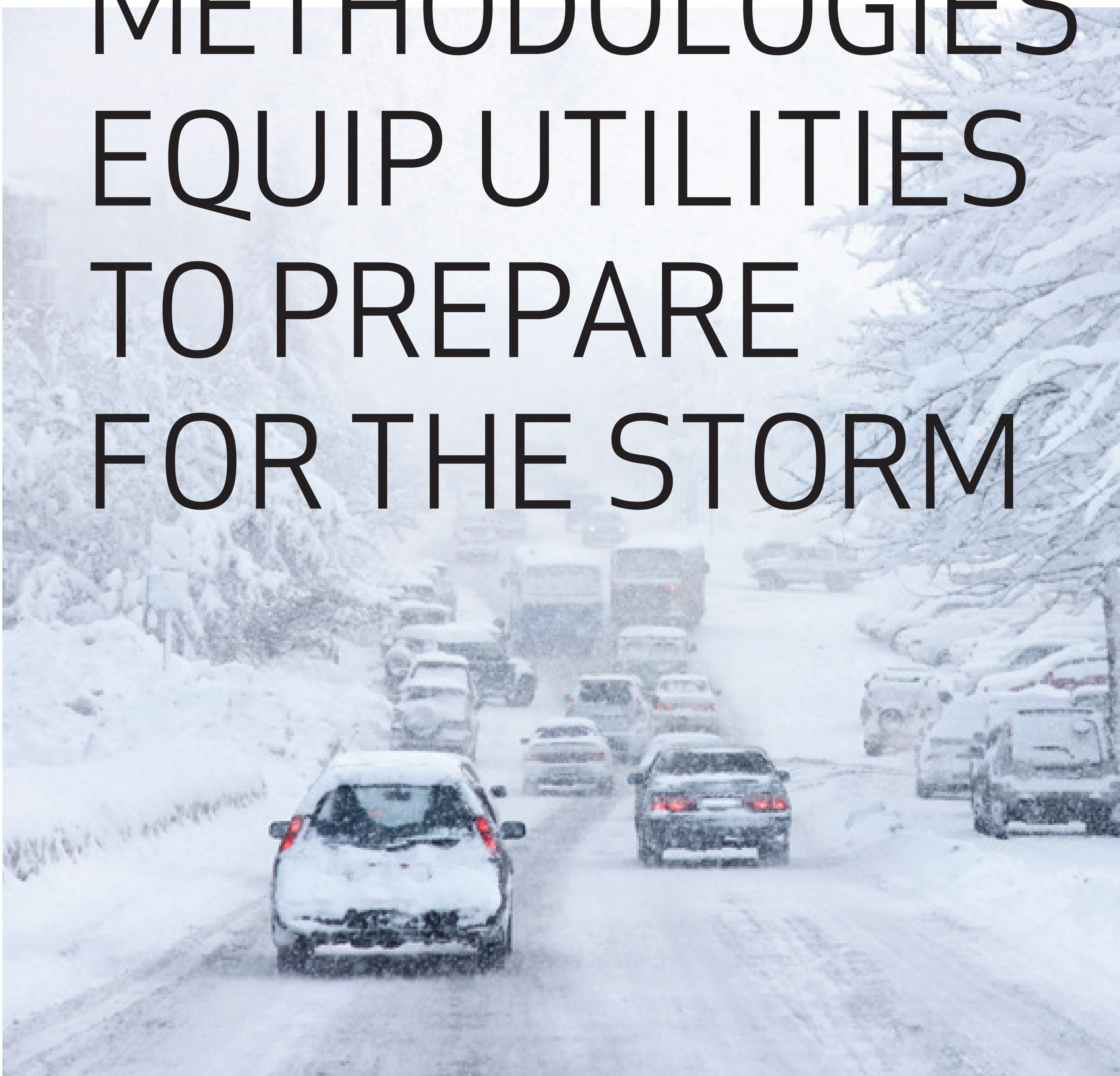
NEW METHODOLOGIES EQUIP UTILITIES TO PREPARE FOR THE STORM



DON LEICK

More than ever before, utilities are under pressure to tackle the threats that severe and volatile weather pose to their operations and bottom lines. Now seen as the new normal, major outages in the United States have increased six-fold in the past 20 years, according to IDC Energy Insights Business Strategy: Facing Down Extreme Weather.

Heightened customer expectations and growing regulatory scrutiny also drive the need for better storm event preparation. Thus, better visibility on the impact of potential weather threats, to improve power restoration response, is of great value to utilities.

This article will discuss the current challenges utilities face when dealing with volatile weather, and why innovative machine learning approaches can be a great fit for improving storm preparation.

Industry Challenges

Long gone are the days utilities could respond quickly after a storm. To put it simply, preparation is required. It may be as simple and short-term as a holdover decision, or deciding how many crews to have on call the night of a storm. Or, it may be as major as a mutual assistance request three or four days in advance of an impending hurricane. Either way, preparation is critical to avoid being underprepared or over-prepared for a storm, which can be very costly. →

Being underprepared can have various negative impacts. Long restoration times, due to inadequate staffing or materials, can be disastrous and instantly become a significant customer satisfaction issue that gains the attention of top management. With social media and increasing media attention, long restorations can result in a public relations crisis that continues long after the storm blows over if customers don't believe their utility was adequately prepared in the first place.

Regulators in many states are increasing pressure on utilities, insisting restoration planning efforts and systems be improved to avoid long outages. The Public Utility Commissions' (PUC) expectations and oversight also seem to be increasing across the country as a whole. And increasingly, governors and other political officials are getting involved.

Utilities are constantly scrutinized, needing to justify all of their operational decisions during significant weather events. As public tolerance for major outages decreases substantially, growing regulatory and political scrutiny can lead to denied cost recovery.

Being over-prepared also is costly. Today, many utilities are operating with leaner organizational structures, meaning outside resources are being used more often for significant weather events. Lining up contractors that end up not being used, but still paid, is not something any utility wants to experience.

It's impossible to always make the perfect preparation decision, but the value in making improvements is enormous – for customer satisfaction, operational costs, avoiding penalties from regulators, and the company's image. Therefore, utilities need a better understanding of the likely damage and the consequent staffing required when a storm is forecasted. Better methods can only help restoration plans be better received by both utility management and outside parties.

New Methodology: Machine Learning

Current approaches to storm preparation usually involve looking at weather forecasts and calling on experience of how similar storms impacted the utility. Consulting with meteorologists is also widely used, which helps greatly in understanding risk. The weather forecast may even be given a numerical storm categorization – where each storm is given a rating for the level of impact on the utility's service territory. That's good, but not enough. An understanding of the damage that will result is needed to gage staffing requirements. Some more advanced utilities have employed statistical techniques – looking at past analog storms and the effects – to try to begin to estimate the potential impact in terms of outages. While better, these simple statistical methods are crude and not very effective. For example, a utility may try to do a regression analysis on wind speed versus outages, which is very over-simplified.

What's a better way? A promising new approach is machine learning. Whether you call it machine learning, artificial intelligence, or neural network algorithms, this is a far more sophisticated and accurate approach to predicting damage and outages.

Machine learning is being deployed successfully in many business applications today, from web search, to credit risk, to estimating equipment time to failure. It's a particularly good fit for the utility damage prediction problem. Machine learning uses history to identify patterns that enable future prediction of outages. Every utility is different, with different designs, age, maintenance practices and so on. Two utilities will be impacted differently by the same weather. In fact, different areas of one utility may respond very differently to the same storm. Machine learning can quite literally learn those differences.

Machine learning can transform weather forecasts into much more actionable information, delivering effective results. Quantitative predictions – such as an estimate of the outage incidents on a utility's service territory – are provided to the operations team well before a storm's arrival. This, in turn, equals faster restoration times, which translates to increased customer, regulatory and internal management satisfaction.

It's All About the Data

What's needed to apply machine learning? A key to machine learning is providing the right, high-quality data to train the machine learning models that do the prediction. Data needed includes:

- **Historical outage incident information from the utility** that is both time-stamped and geo-located (i.e., latitude and longitude). Typically, three to five years of outage incidents (trouble spots) are required to adequately train the models, but in general, the more data the better.
- **Historical weather information** corresponding to a utility's weather-related outages. This also needs to be very high resolution, gridded data.
- **Utility's overhead distribution system data** in geospatial form. It's important for the machine learning to know where poles, lines and isolating (protective) devices are located. A simple example illustrates why this is important: the more lines a utility has in an area, the more likely there will be a problem.
- **Tree trimming history** to understand where the utility is in its four- to five-year cycle. This is very useful, if available, as it improves the accuracy of predictions. For example, if trees were trimmed a year ago, there will be fewer outages than if trimmed four years ago.
- **Factoring in trees** to determine where they are in proximity to lines, and when the spring/fall leaf changeover occurs for deciduous trees.

This data is then leveraged to build predictive damage models specific to each type of weather event (i.e., thunderstorms, snow, wind, hurricane, etc.). These models can then be used going forward to predict the impact of future storms based on forecasted weather.

In reality, there will be a number of predictive models used for the type of storm expected. Different machine learning algorithms are then aggregated together to get a range of potential incidents on a utility's territory.

Machine learning technology can determine where outages will be throughout a utility's entire network, identifying areas that will be most affected, allowing operations teams to better plan for staging, pre-positioning, or simply alerting local crews. It can also provide useful resiliency insights, highlighting areas of weakness, as illustrated by outage incident history and the damage forecasts themselves.

As exciting as machine learning is, maybe you can start to see that the devil is in the details. It's not a simple process or something that utilities can do themselves. However, the good news is that vendors have built productized solutions, specifically for the damage prediction problem, that can be applied to a specific utility. Utilities don't have to be experts in the machine learning, the unique weather requirements, the needed third party data sources or the specialized data processing. It doesn't have to be a high-risk science project or a long open-ended consulting engagement. The utility simply provides its available data.

Validating Predictions Before a Storm Hits

If utilities are going to begin to use machine learning to make critical staffing decisions, they first really need to understand the reliability of its predictions. One huge benefit of machine learning is its ability to validate the accuracy of a model – for that utility – before putting it into operation. That's due to cross validation techniques. For example, let's say that a utility's wind event model has been built with information from 100 previous storms. In order to cross validate the model, rebuilds of the model include storm and outage information from →

99 of the 100 storms, leaving out the 100th storm. The model is then run against that 100th storm. The model has no knowledge of the storm and it is just as though it is generating a prediction for forecasted weather. Then, this process is repeated to create a prediction for a second storm, rebuilding the model with the other 99 storms. This step is repeated for every one of the 100 storms, and accuracy metrics are compiled.

By doing this, a utility is able to reliably understand how accurate the model is, as if it's had years of experience with it. This cross validation also identifies the strengths and weaknesses of the prediction system. For example, one issue might be that utilities simply don't have enough data for a particular type of storm, such as a hurricane. As a utility accumulates more data, the model can be retrained with the latest storm data, including rare events like hurricanes. When a utility collects more data, the forecasts become more reliable.

Time to Move On

If the fires, hurricanes and various storms of 2017 are any indication of what the future might hold, utilities need to be better prepared.

Weather forecasts and meteorological consulting, while still very important, are no longer sufficient. Machine learning can provide an effective prediction of a storm's impact and projected damage. This quantitative predictive information can be a major driver in preparation decisions, and significantly improve a utility's overall restoration response. A machine learning solution can help a utility hit the right levels of preparation before the storm, reducing the frequency of being underprepared or over-prepared. The time is now for utilities to use these decision-support technologies that can change the way of doing business for the better.

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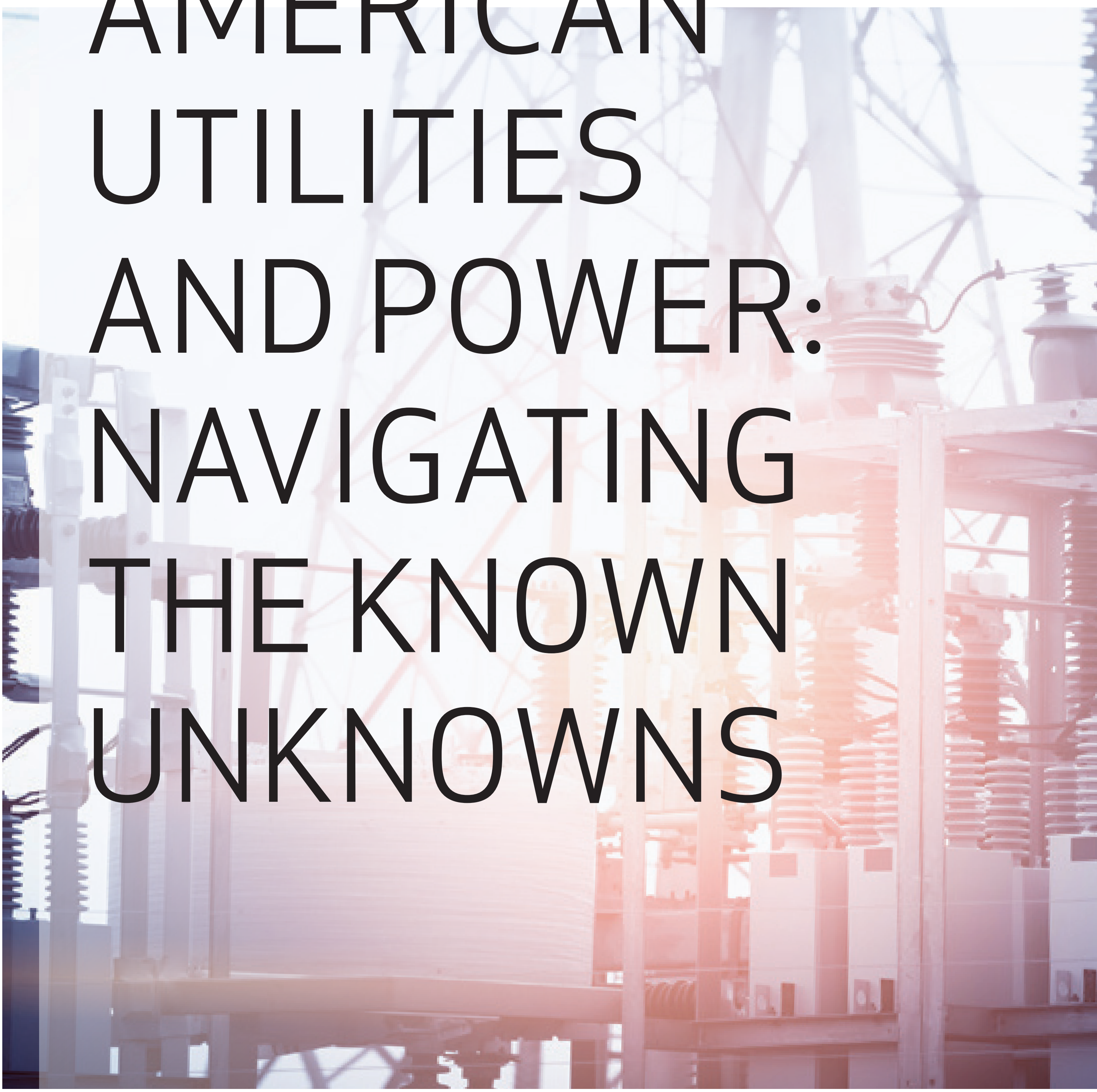
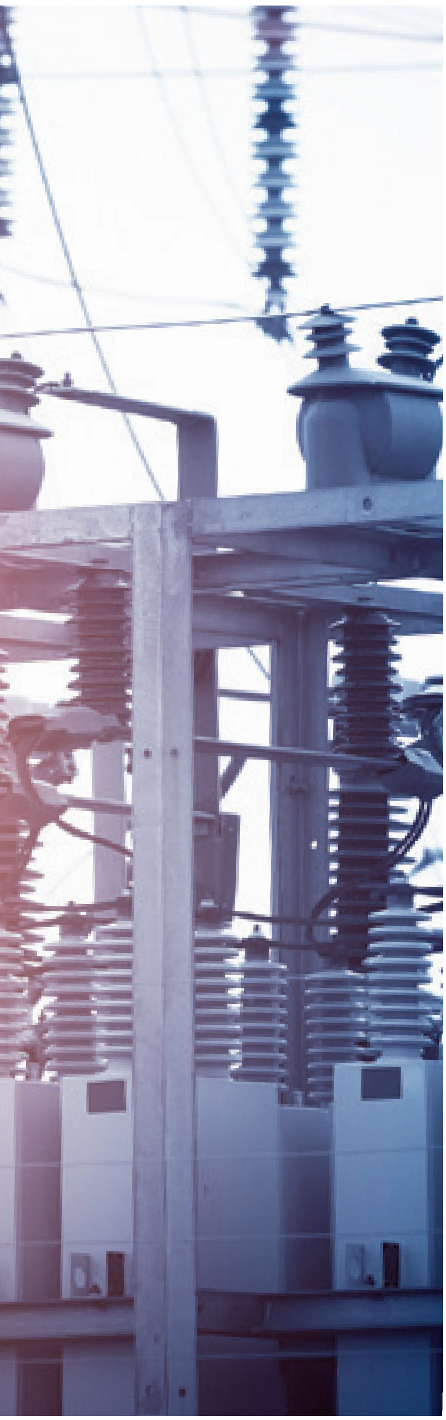
THE BIGGER PICTURE

NORTH AMERICAN UTILITIES AND POWER: NAVIGATING THE KNOWN UNKNOWNS





ANEESH PRABHU AND TODD SHIPMAN

For a time, North America's regulated utilities and merchant power generators were negotiating a market characterised by "known unknowns." For regulated utilities, chief among them was the uncertainty around tax reform, which has now begun to be addressed. The same cannot be said for merchant generators. Management teams are pondering the extent to which energy efficiency and disruptive technology advancements will necessitate strategic modifications.

So, what is the outlook for North America's electricity companies? On the horizon, both regulated utilities and merchant generators should remain mostly stable. For merchant power, 55 percent of rated independent power producers (IPPs) enjoy stable outlooks, though there is a negative bias on the IPPs with other outlooks. Regulated utilities, meanwhile, are also mostly stable – supported by robust regulatory oversight.

Although the dust has settled on the details of U.S. tax reform, North American utilities are still subject to many uncertainties. Pressure, for instance, comes from the burgeoning of renewable and battery storage capabilities and weak demand growth. That said, the industry overall appears well positioned to withstand the mild shocks emerging in the medium term. →

Regulated Utilities: Short-term Shocks to Subside

Importantly, while the U.S. tax reform bill may pressure regulated utilities in the immediate term, this should subside. The reduction of corporate rates to 21 percent, from 35 percent, prompts regulated utilities to pass along their savings to customers[1]. This could weigh more heavily on the cash-based credit metrics. The impact will vary between companies depending on each utility's unique tax position, but – generally speaking – we can expect cash flows to weaken. This will take place once utilities begin passing savings to the ratepayer and feel the loss of tax incentives from reforms.

This is mostly manageable, however. The effects are unlikely to be pronounced enough to prevent companies from compensating. For those companies with heightened financial risk, however, the ramifications of tax reform could spur a rating change – should they not strengthen their credit profiles. All things considered, we expect few rating actions as a direct result of U.S. tax reform. This is because regulators, we think, will continue to ensure utilities operate in a favourable environment for returns and credit quality. Of course, as unpredictable as regulatory behaviour can be, the economic conditions in many regions have enabled utility regulators to support generators' earnings and cash flow stability.

Buoyed by these conditions, capital spending is likely to remain a focus for utility management teams as they meet infrastructure needs. These upgrades appear necessary. Regulated electric utilities are strategically modifying their generation fleets to reduce air emissions from power plants, to justify the shuttering of aging coal plants and to replace carbon-emitting plants with lower or zero-emission sources. As part of this, utilities are moving away from bigger, base load generators (namely coal and nuclear) to more modular and scalable renewable sources.

Amid industry disruptions, merger and acquisition (M&A) activity could increase. Now that the uncertainties surrounding tax reform are removed, determining the value of utilities (and necessary capital costs) is becoming more certain, too. With capital costs still below historical averages, a flurry of transactions could appear this year. Increasingly popular for North American gas and electricity utilities are cross-industry and cross-border acquisitions – a trend that could continue during 2018.

Merchant Generators: Headwinds Ahead?

The greatest influence on merchant generators' credit quality, meanwhile, will likely be electric demand growth (or lack thereof). Most merchant generators have blamed waning growth on the milder weather over the past two-to-three years. In turn, almost all generation forecast models factor in demand growth between 0.75 percent and 1 percent – a seemingly optimistic expectation, pinned on hope rather than a business strategy.

As such, we believe the most significant risk to merchant energy margins and capacity price assumptions is a decline in secular demand growth. And, for the time being, estimating the severity of the impact of faltering demand is proving troublesome. Implied load in the PJM auction, for instance, has fallen over the past four years – leaving a negative 1.2 percent compound annual growth rate (CAGR). With demand declining, capacity prices are falling, too. Other markets are experiencing a similar trend: the 30-gigawatt (GW) ISO-NE market has grown at negative 0.5 percent for the past three years.

Further pressuring merchant generators, is the falling cost of renewable energy. Since 2009, solar PV installed system costs have fallen for residential and commercial systems and for industrial utility-scale systems, by 60 percent and 70 percent per kilowatt (kW), respectively. Wind generation has proliferated, too: for instance, wind power comprised 17 percent of the load in the ERCOT market in 2016. In turn, Exelon Generation found that round-the-clock prices at some generators in its nuclear fleet are now US$3.00/ MWh lower, largely, thanks to the competition.

Energy efficiency gains could also dim prospects. Arguably, market participants are still downplaying the potential ramifications of energy efficiency advancements. While LED lighting penetration remains low, it is expected to increase to 25 percent by 2020, from 8 percent today – leading to a 4 percent decline in power demand.

This is no inconsequential number: for perspective, the 2016 Department of Energy (DoE) report estimates that LED lighting-related savings will be approximately 325 terawatt hours (TWh) per annum in 2030, when compared to 2015 levels. And this may not be effectively offset by the advent of electric vehicles, either. Forecasts by the S&P Market Intelligence Group put power demand from car and light trucks at 172 TWh per annum by 2035. Mitigating these revenues pressures, therefore, will rise up the agenda in the longer term.

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Overcoming Mild Shocks

Certainly, transformative risks abound in North America's utility space – and this is especially true for electric utilities. The energy transition, spurred by carbon concerns and other environmental considerations, is prompting generators to pursue a more diverse energy mix.

This brings some potential upsides, too: in the regulated market, the amalgamation of growing renewables and battery storage technology presents some opportunities for growth. Though storage technology is still nascent, we expect that – as battery prices fall – utilities will evolve to meet the grid's needs. So, despite the shocks and prospects for disruption ahead, regulated utilities and merchant generators alike only display slight downside rating exposure.

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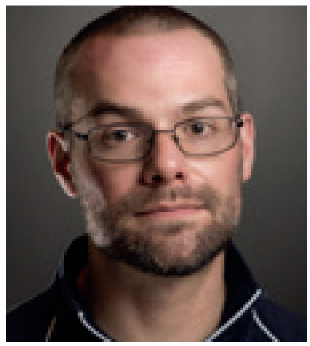
COMBATING ICS THREATS



JOE SLOWIK

Introduction

2017 featured a number of concerning discoveries in industrial control systems (ICS) network security: targeted, disruptive attacks; ICS-focused threat activity groups, and increasing permeability between IT and ICS networks. Underlying these developments is an increase in ICS security visibility and awareness, allowing asset owners and defenders to finally glimpse the full scale of the ICS threat landscape. As adversaries continue to refine their tactics and threats evolve into new and potentially more harmful forms, defenders should not take events as a sign of defensive weakness. Rather, with increased visibility comes the possibility to improve and refine knowledge and defensive methodology. By studying and reviewing the threats facing ICS environments, network defenders can formulate plans and procedures against entire methods of operation — instead of specific examples of ICS intrusions — to build more robust protections. By adopting this threat-centric, iterative approach, defenders can keep pace with malicious actors and work to ensure ICS network security.

ICS Threats: A Growing Concern

2017 saw an increased identified ICS security activity — from targeted attacks displaying significant skill and expertise — to IT-focused malware that resulted in substantial ICS impacts. While the amount of recorded activity increased, this more than likely represents an increase in visibility and effort on the part of defenders as attacks are actually caught and observed. Outside of truly destructive attacks – from STUXNET[1] to the German steel mill event[2] to CRASHOVERRIDE[3] — ICS intrusions will typically not register in traditional security metrics if they are even caught at all. For reference, ICS-CERT's Year in Review indicates that organizations struggle to determine the origin and impact of potential intrusion events, →

as shown in the predominance of "unknown" for various metrics surrounding ICS security events and impacts[4]. With greater attention and effort comes enhanced visibility and awareness, shedding light on the true scope of the ICS threat landscape.

This increased attention in 2017 yielded surprising results: two targeted, destructive attacks identified; at least five activity groups targeting ICS networks; and multiple low-level, commodity infection events indicative of increasing interconnectedness between IT and ICS resources. Throughout 2017, the predominant reaction to events was not, "why are there so few events?" but rather "why are there so many?" Moreover, we believe with high confidence that the brief overview of activity above only scratches the surface of what actually occurred throughout the year.

As ICS defense matures and visibility increases, many of these presently "hidden" items will come into view. But, we must learn from what we can see to identify how threats operate, so we can best approach how to defeat them. A truly threat-focused approach to ICS network defense will take the specific examples learned through, in this case, a year's experience and extrapolate to capture entire classes or categories of potential adversary behaviors. The ICS community will meet the increasing challenge of motivated adversaries only through rigorous analysis and understanding of the threat environment, combined with a dedication to root-cause analysis to eliminate "unknowns."

Targeted Attacks

The headline-grabbing ICS security items for 2017 were two targeted, disruptive attacks: the CRASHOVERRIDE event in Ukraine (launched in December 2016, but not fully understood until mid-2017); and the TRISIS attack on safety instrumented systems (SIS) in August 2017[5]. Both events pushed the boundaries of ICS threats in their own unique ways: CRASHOVERRIDE by demonstrating the ability to impact electric grid operations directly through malware; and TRISIS by expanding ICS targeting to SIS devices. In the case of the former, the adversary created a "playbook" for how to create and deploy a flexible malware framework leading to an ICS impact (in this case, a power outage). For the latter, the attacker pushed the boundaries of ICS targeting beyond standard operational elements to the equipment tasked with safeguarding equipment and human lives.

The impacts of both events on the wider ICS community are clear and disturbing. First, adversaries are moving beyond the direct, manual manipulation of ICS controls (as seen in the 2015 Ukraine attack[6]) to more automated and potentially autonomous means of delivering an ICS effect. Second, adversaries clearly demonstrated that no part of the ICS network — or its supporting functions and equipment — is safe from potential malicious activity. To further this last point, the TRISIS event implicitly includes the adversary's acceptance of risk that the event could result in potential harm to human life.

While CRASHOVERRIDE and TRISIS represent the "highlight" events for 2017, significant activity took place beneath the headlines. Most importantly, at least five dedicated ICS threat activity groups emerged over the course of the year. Some of these, such as the COVELLITE adversary, are linked to known IT intrusion behavior, while others, such as DYMALLOY, appear to be an evolution of past ICS activity[7]. While only a handful demonstrated the ability to migrate into the ICS network from initial IT beachheads with an ability to then navigate the ICS environment, all showed a clear intent of gathering information on and preparing for future operations in ICS networks.

Based on observed activity, multiple groups continue to probe ICS-related networks, and new methods of operation within ICS environments – particularly with respect to causing disruption – emerged for all current and potential threat vectors to emulate. Given the assumption that observed activity does not represent all that took place in 2017, the expectation for defenders should be continued efforts to build, develop, and refine operations targeting ICS environments as we move into 2018.

The Disappearing IT-ICS Divide

Less focused on ICS networks but of grave importance to ICS defense, several strains of wormable malware emerged over the course of 2017, which demonstrated unequivocally that IT and ICS networks are more tightly linked than many would care to believe. Beginning in Spring 2017 with WannaCry and moving through the Fall with BadRabbit, new, highly virulent malware strains proved capable of bridging the IT-ICS network divide with highly disruptive – and in some cases destructive – results.

The first piece of wormable malware, WannaCry, leveraged recently-disclosed vulnerabilities and their related exploits to produce a ransomware-like infection that quickly spanned the globe. While much attention focused on impacts to entities such as the UK's National Health Service, WannaCry proved quite capable of impacting the ICS environment as various entities witnessed production-halting infections.

Fueling the WannaCry event were the vulnerabilities patched by Microsoft under MS17-010: various weaknesses in version 1 of the Server Message Block (SMBv1) protocol targeted by the released exploits. More significantly, SMBv1 features prominently in both intra-ICS and IT-ICS communication links, due to older systems, legacy protocols, and outdated methods of data transfer. The result was an infection event that spread from initial IT nodes to impact ICS networks. The mantra of just applying the patch proved of little value, given the various elements of ICS network operation that prevent quick application of software updates: long periods of time between maintenance windows, potential application incompatibility, and lack of vendor support. All of these factors combine to make the MS17-010 vulnerabilities lasting concerns within the ICS network.

After WannaCry, new wormable malware strains emerged, which added an operational wrinkle to propagation methods. These strains, NotPetya and BadRabbit, leveraged a combination of exploits with credential capture and replay to spread throughout target networks. In this case, even systems that either patched the underlying vulnerabilities or never exposed such services to exploitation to begin with, faced the possibility of compromise. More significantly for ICS networks, the method of propagation is uniquely suited to IT-ICS communication: an engineer's IT workstation could be compromised, yielding credentials that would enable remote access to the ICS network. Follow-on propagation within the ICS network would be fueled by weak authentication schema and credential re-use. Overall, the result is a uniquely virulent infection and propagation method that has the potential to rapidly impact ICS networks.

verall, the conclusion from these events – none of them explicitly targeting ICS infrastructure – is that thoughts of strictly segmented and divided IT and ICS networks are unrealistic. With relatively unsophisticated malware worming its way into sensitive, supposedly isolated networks, the barriers to entry for launching truly disruptive attacks are significantly lowered.

Combining Skilled Adversaries with Asset Convergence

The previous two sections highlight two seemingly unrelated trends: an increase in skilled, targeted adversaries within ICS, and the increasing impact of IT-focused malware on ICS environments. While each is useful to consider in isolation, combined, they could present a truly worrying trend for the future threat landscape.

Just as CRASHOVERRIDE and TRISIS provide operational "playbooks" for adversaries on how to disrupt ICS operations, WannaCry and subsequent events demonstrate the potency of wormable malware in penetrating sensitive networks. Considering that the first high-profile ICS malware, STUXNET, was a worm designed to compromise isolated network environments, this method of self-propagation to achieve access should not be surprising. Yet the simplicity of more recent network worms, and the efficacy of their propagation methods with respect to ICS, provide a unique and potent mechanism for harming these environments.

Defenders should expect adversaries to embrace this lesson and apply these "less sophisticated" techniques as a means to achieve initial ICS network access. While ICS disruptive effects will still require significant investments of time, energy, and resources to both develop and then deploy impacts to the ICS environment, one significant barrier to entry is reduced: the need to penetrate and compromise multiple nodes en route from the IT to target hosts within the ICS realm. →

As a hypothetical, an adversary could repurpose one of these wormable samples to specifically target ICS resources — for example, by seeding the malware with sets of known ICS vendor-hardcoded credentials — and utilize this to gain initial access throughout the ICS network. After these compromised endpoints are identified and researched, the adversary then need only move required malicious impact software, such as a TRISIS or CRASHOVERRIDE, along these compromised pathways to create a disruptive ICS effect.

Conclusion

2017 featured a number of interesting and potentially alarming developments in ICS security: the discovery of two highly-targeted ICS attacks, the emergence of at least five specific groups working to compromise ICS networks, and several widespread IT infection events that produced significant ICS disruption. While this represents a concerning development in ICS network defense, ICS operators and defenders must view this as a point on a rising trendline, rather than a high-water mark in ICS malicious activity.

As visibility and awareness of ICS security issues continue to develop, ICS defenders should expect to uncover more malicious actors — and potentially more targeted attacks than were disclosed in 2017. While this may represent a worrying set of circumstances, greater visibility and transparency means that defenders will also be better positioned to respond to events. Rather than simply wait to be surprised by intrusions, defenders can work to build knowledge and experience off of disclosed attacks to build better defenses and operational resilience.

To this end, ICS asset owners and defenders should look at the substantial increase in identified, disclosed ICS events and malicious activity groups as an opportunity — a chance to learn what tradecraft, techniques, and methods are employed by malicious actors to build better defenses against these threat vectors. By abstracting from specific events to highlight operational commonalities and dependencies across all attacks, defenders can begin to focus and prioritize resources in an effort to confront and deny adversaries their likely objectives. Adopting this threat-centric model ensures network defenders remain poised to respond to actual, likely attack scenarios, and when adopted in a sufficiently 'general' manner, counter entire classes of malicious activity, rather than simply repetitions of previously observed events.

Examples of the above approach applied to activity observed in 2017 can take multiple forms. One of the most obvious and pressing is limiting and defending IT-ICS connections. These vital links bridging the more accessible IT network with the critical and potentially vulnerable ICS network provide a crucial first-line of defense against both targeted attacks and self-propagating malware. Hardening these links by applying strong authentication mechanisms, reducing the number of links to the minimum necessary for operations, and applying robust monitoring of IT-ICS network communication can all be used to shore up this vital node for any potential ICS intrusion.

Overall, defenders should be concerned with recent developments, but avoid panic. With greater awareness and visibility, we should expect to identify more adversaries operating in ICS networks. Instead of treating this as cause for unproductive alarm, defenders can utilize this new corpus of knowledge to bolster and strengthen defenses to meet these adversaries head-on. By adopting this aggressive, threat-centric approach, ICS networks can be protected against all types of malicious activity — from highly specific targeted attacks to opportunistic infections, to hybrids of these two approaches.

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7. Further details on activity groups COVELLITE, DYMALLOY, and others can be found in Dragos' 2017 Review of Industrial Control System Threats

ABOUT THE AUTHOR:

Joe Slowik is an adversary hunter for Dragos, pursuing threat activity groups through their malware, their communications, and any other observables available. Prior to his time at Dragos, Slowik ran the Incident Response team at Los Alamos National Laboratory, and served as an Information Warfare Officer in the US Navy. Throughout his career in network defense, Slowik has consistently worked to "take the fight to the adversary" by applying forward-looking, active defense measures to constantly keep threat actors off balance.