

2019
Black & Veatch
Strategic Directions

SMART UTILITIES REPORT



About This Report

As their infrastructure continues to gray with age and customers demand doing more with less, utilities and their business models are being tested by evolving technology that's prodding them to modernize. After all, adding next-generation advances can enhance operational efficiencies, customer engagement and network resilience in a constantly changing energy ecosystem.

Powered by an expansive survey of the industry, the Black & Veatch *2019 Strategic Directions: Smart Utilities Report* looks beyond grid modernization and takes a deep, close assessment of all of that — and more.

According to our data, transformational initiatives — from greater integration of distributed energy resources (DER) and the untamed proliferation of electric vehicles — are pressing on. The grid's edge — where utilities interact with their customers — invariably will have to be autonomous and interactive to satisfy tomorrow's energy demands.

After taking the industry's latest temperature, we see the evolution toward smarter infrastructure as possible and that obstacles — no matter how daunting — can be conquered. The *2019 Strategic Directions: Smart Utilities Report* details the hurdles while analyzing such topics as distribution modernization and automation, field area networks (FAN), security, network management services, asset management and DER market enablement.

We welcome your questions and comments regarding this report or Black & Veatch services. You can reach us at [**MediaInfo@bv.com**](mailto:MediaInfo@bv.com).

Sincerely,

JOHN CHEVRETTE | President, Management Consulting

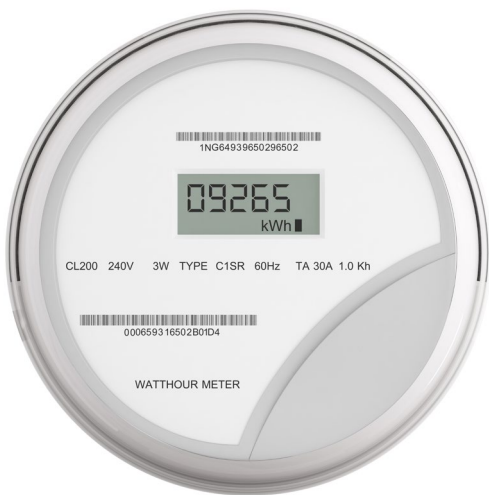
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Executive Summary

**GRID EDGE BECOMES THE CENTER
OF NEXT-GENERATION UTILITIES**

By John Janchar

Digital technology and networks are breathing life into utilities' aging distribution systems just as distributed energy resources (DER) and renewable energy are challenging traditional business models and centralized generation.

With the decentralization of generation, the edge is coming into focus. Economical advances in energy production, storage and control are giving rise to the prosumer, driving consumer choice and ultimately producing a new energy marketplace at the local distribution level. However, utilities now are left to wonder how they're going to manage two-way power flow and variable DER while maintaining the reliability, efficiency and security of their operations. Distribution modernization is inevitable, and making the grid edge autonomous and interactive is paramount for satisfying tomorrow's energy demands.

ABOUT THE AUTHOR

John Janchar is the President of Black & Veatch's Telecommunications business, including Public Networks, Private Networks, Connected Communities, and Transformative Technologies lines of business. Previously, he served as executive vice president of Telecommunications and a member of the company's Growth Council and Safety Leadership Team.

Black & Veatch's latest snapshot of the industry, the *2019 Strategic Directions: Smart Utilities Report*, crystallizes what's top of mind among overseers of electric networks. According to the report's survey of industry insiders, respondents overwhelmingly declared that increased monitoring, control and automation capabilities — along with improving grid reliability — are the top drivers of modernizing their electric distribution systems.

And they say they're ready to spend a considerable amount to make it happen. Roughly one of every five respondents say their utility plans to pour more than \$200 million into modernization over the next three years. An additional 26 percent report they'll devote \$100 million to \$200 million to that cause.

As the edges of utilities' grids are adapting to the deployment of disruptive technologies such as DER — things such as microgrids, rooftop solar and fuel cells — Black & Veatch's report explores the industry's weightiest issues.

- **Distribution Modernization/Automation:** The key drivers of the investments that utilities are making in distribution system modernization stem, perhaps ironically, from assets that utilities often don't own, namely DER such as rooftop solar arrays, electric vehicles and battery energy storage systems.
- **Field Area Networks:** The electric grid is undergoing its most transformational shift in history with digital technologies and devices being pushed to the edge to support dynamic two-way power requirements in real-time while ensuring reliability, efficiency and security. As these digital devices approach the edge and are densified across the grid by more than 1,500 percent, utilities need an advanced wireless network that goes beyond supporting Advanced Metering Infrastructure (AMI) and supervisory control and data acquisition (SCADA) devices that traditional field area networks (FANs) support

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Consumers are empowered and becoming more technologically savvy and digitized by the day, thanks to the rise of smart metering and other intriguing gadgetry.

today. A majority of the respondents to this report's survey say the existing field area networks they're using for AMI and SCADA will need significant enhancements to support the digital utility of tomorrow. Now the question is, what's the right technology solution?

- **Low-Impact Assessments and Security:** Utilities recognize the critical role that cybersecurity plays in ensuring the health, reliability and resilience of the electric grid, and for years, the focus was on protecting the high- and medium-impact assets that make up the bulk electric system. But a NERC CIP. standard issued in early 2018 is changing the game by mandating that utilities extend proper cyber protections to all low-impact assets on the grid by 2020. The distributed nature of these projects — from the multiple site types to the sheer volume of devices — makes implementing this standard a daunting task. Where does the industry stand in bringing itself into compliance?
- **Network Management Services:** Advocates of the Internet of Things (IoT) and other integrated technologies have done an admirable job of selling utilities on the value of smart devices: With applications before and behind the meter, network intelligence strategies involving AMI and other technologies carry the promise of unprecedented volumes of data about customer habits, asset health, system outages and other anomalies. But a key question persists: How can you best manage the network?
- **Whole Systems Asset Management:** Driven by a desire for increased monitoring and improved reliability, plus the need to integrate DER, utilities are working to bring a massive new array of assets online in the distribution space. The speed, scale and complexity at which these advanced systems deploy will require visualization and immersive interaction wholly unachievable with today's methodologies, paving the way for a revolution in asset management. As a result, conventional "replace and repair" asset management approaches will have no place in this future world and are being quickly eclipsed by a more holistic, whole-systems perspective.
- **DER Market Enablement:** Utilities are beginning to embrace the ever-increasing presence of DER in their regions. But to animate the DER market and allow investors to sell their energy into the system, a new organizational body must be formed that can manage this new source of power flow onto the grid.

Without question, the way utilities and customers engage is shifting. Consumers are empowered and becoming more technologically savvy and digitized by the day, thanks to the rise of smart metering and other intriguing gadgetry like smartphone apps that give them more control and functionality over their energy. They also can readily switch between suppliers and pressure utilities to prize customer service to stifle customer attrition or the potential fallout of bad publicity on influential, broad social media.

Enter the pressing import of grid modernization — now.

Disruptive Green Energy Changing Rules on the Grid



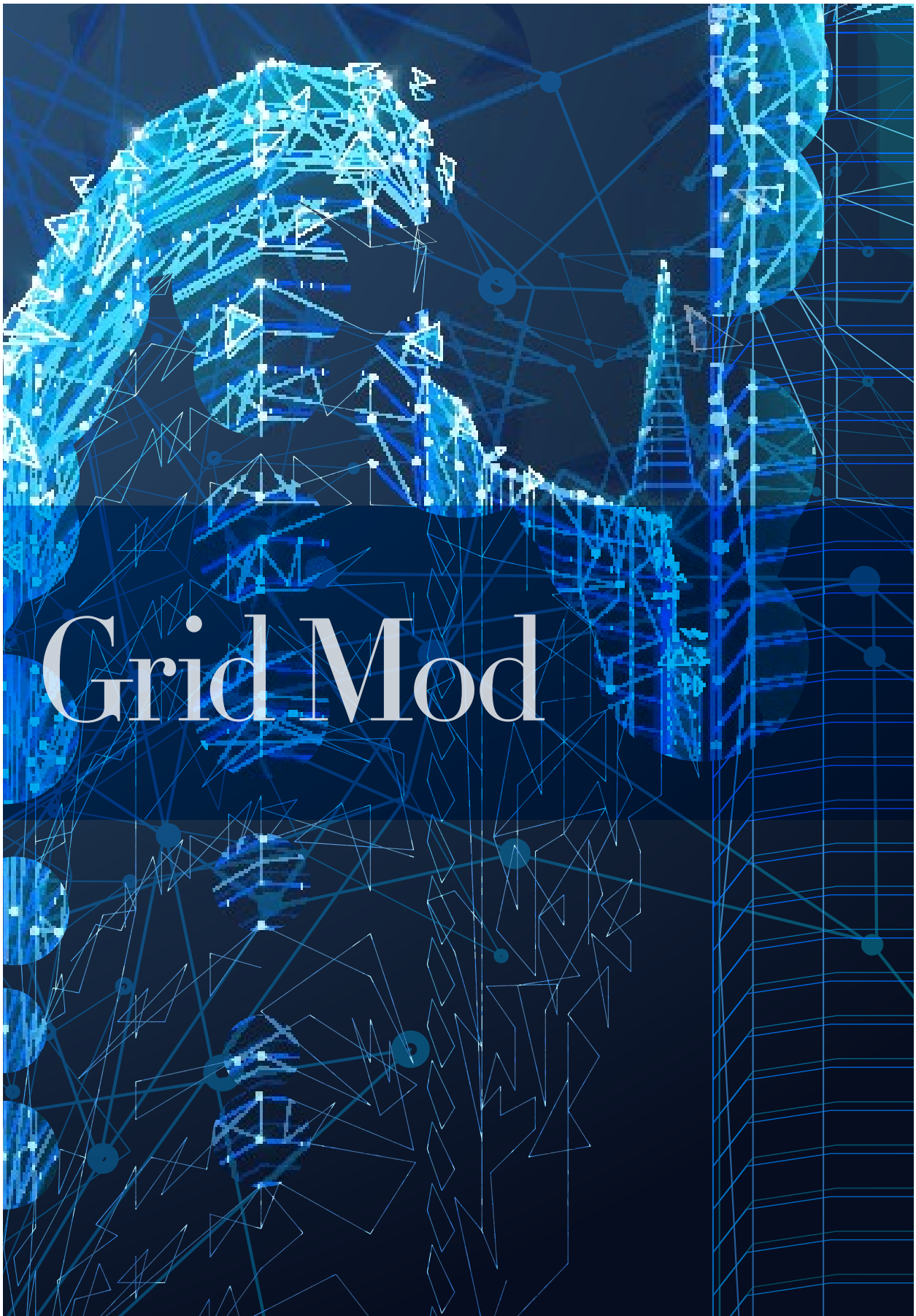
As disruption unsettles traditional distribution systems, the need for command-and-control sophistication mounts as renewables — solar and wind — churn out more power at the edge. Communications, automation and security are critical in managing the industry's transition from centralized, one-way power flow to a decentralized, two-way flow that helps make the grid essentially a plug-and-play proposition. DERs are fanning the need for monitoring and control out to the edge to manage energy supply variances caused by green energy.

To that end, utilities are orchestrating smarter ways to gather and analyze efficiency-bolstering data, appreciative that upfront investments now can reap longer-term value. Flexible, scalable FANs are fundamental to constantly communicate with edge devices to share real-time data that impact a utility's decision-making; utilities prefer private FANs that need access to the spectrum and deliver better control over the network, ensuring that coverage and reliability requirements are met.

As grid modernization takes deeper root, a widening array of technology — such as smart metering and automation technology — will be added to the grid, making sharp planning and management tools essential in deploying, tracking and managing what could be millions of assets. Adopting smarter ways to gather and analyze data to bolster efficiency is paramount.

That heavy lifting — and the financial commitment it entails — to overcome tomorrow's hurdles and possible pain points, including deepening penetration of DER and escalating residency in urban areas, requires innovation and a forward-thinking mindset.

In this new normal, DER and the march of technology are changing the game of power delivery. Utilities no longer can afford to stay on the sidelines. ■



Grid Mod

ABOUT THE AUTHORS

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Gary Johnson is a sales director for Black & Veatch's Private Networks business. An electrical engineer, Johnson is experienced in mapping the geology of oil wells in West Africa. Following his MBA, he has been involved in various aspects of the electric power industry, including, metering, generation, transmission and, for the past 20 years, private networks and utility automation.

Heather Sanders is a director in Black & Veatch's Management Consulting business. She is a recognized thought leader serving as a member and advisor in forums focused on enabling technical capabilities, business model and policy changes. Sanders' experience spans electricity industry domains, including distributed energy resource integration, grid modernization, wholesale markets, and distribution and transmission.

Modernization Plans Target DER-Ready Distribution Systems

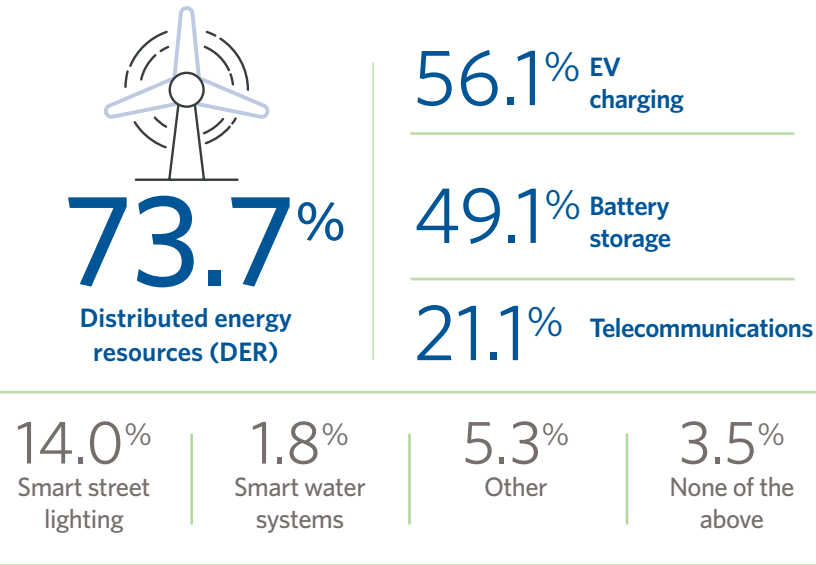
By Paul McRoberts, Gary Johnson and Heather Sanders

Here's a bit of irony: The key drivers of the investments that utilities are making in distribution system modernization stem from assets that utilities often don't own. In this case, we're talking about distributed energy resources (DER) such as rooftop solar arrays, electric vehicles and battery energy storage systems.

DER is by far the top application that utilities are planning to support in the next three to five years, according to industry responses to a survey for the 2019 Strategic Directions: Smart Utilities Report. Nearly three-quarters of respondents cited DER in general as shaping their distribution infrastructure in the coming years, while some 56 percent named electric vehicle (EV) charging and nearly half named battery storage, both of which are DER that someday could be controlled and dispatched to support the overall power system. That's where we're headed (Figure 1).

Figure 1

What are the most important applications YOUR distribution infrastructure will have to support in the next three to five years? (Select up to three of the following)



Source: Black & Veatch

What's Going On

Planning is one of the biggest challenges that DER presents to utilities, which previously looked mostly at their own assets. So is it time to install new conductors? New transformers? What will be needed to support peak loads? Utilities also need to factor in the various resources and assets that customers want to pile onto the electric system.

Decentralization mandates a different kind of planning than what utilities have done in the past, and they will likely want to bring analytics into the process. With analytics, power providers will be able to look at the grid through multiple lenses, including what-if scenarios for DER growth, which assets to tap to achieve optimal economics, and where to place asset management devices like sensors, volt/VAR equipment and more. That's in addition to what may be coming down the road in the future.

Most utilities already are studying how behind-the-meter resources impact the grid. Many also are looking at how the utility can use customer assets — like smart inverters — to aid in things such as volt/VAR management or whether the resource could come into play as some sort of additional capacity in an emergency.

Some utilities also are starting to question the optimal place for customers to add generation resources, particularly big ones like megawatt-scale storage or microgrids. One utility recently offered to subsidize a local university for putting in DER to take load off of a substation. The project would spare the utility expensive substation upgrades in the coming years.

Another utility used Black & Veatch analytics tools to map out how to achieve its goal of 100-percent renewable energy by 2045. Those analytics reveal how decentralization was likely to occur, when to "green up" different parts of the system, and where and when to replace fossil-fuel-based generation with wind or solar power. The game plan is expected to shave time off the utility's original plan.

Part of that utility's modernization and carbon-reduction efforts included putting advanced metering infrastructure (AMI) in place to provide better information for the analytics engine.

What Counts

Along with delivering valuable data — consumption data and power-quality metrics — AMI facilitates grid-supportive initiatives like time-based rates and targeted load shedding that can deliver a non-wires means of deferring grid upgrades and investments. These are some of the reasons why survey respondents picked AMI as the top distribution automation solution planned at their utility. It was the choice of more than three-quarters of respondents. Fault location, isolation and service restoration (FLISR) technology came in as the second most-favored choice, earning a thumbs up from two-thirds of respondents. Advanced distribution management systems were up there, too, with a nod from 62 percent of survey takers.

All of these upgrades bring in loads of data, but there is a big difference between receiving data and being able to use it. Utilities recognize this, likely explaining why integrating DER and asset management with analytics were also popular picks with survey respondents. Fifty-seven percent said these capabilities were planned for their organizations.

Both AMI and the sensors associated with a FLISR solution support the main drivers that utilities named for grid modernization efforts. Eighty-four percent of survey takers said they were modernizing their distribution system to increase monitoring, control, and automation capabilities. Two other drivers — improved reliability and improved operational efficiency plus volt/VAR management — were selected by 82 percent of survey takers. AMI supports all of these drivers.

For instance, by analyzing blink counts, utilities can pinpoint feeders with excessive transient outages

Figure 2

What are the top three barriers your utility is facing to enable smart distribution infrastructure? (Select up to three of the following)

62.5%

- Budget constraints
- Other competing priorities

48.2% Regulatory hurdles

28.6%

Lack of resources or expertise

17.9%

Ownership across departments

12.5%

- Gaining stakeholder support

- Unwillingness to look at opportunities in the unregulated arena

10.7%

Availability of technology

3.6%

Other

Source: Black & Veatch

so that crews can investigate possible causes, such as vegetation or animal-intrusion issues. That helps reliability. Likewise, newer AMI meters can deliver power quality data, which means those equipped with this functionality can be strategically placed around the distribution system to serve as bellwethers to voltage sags and spikes and/or frequency excursions.

Analytics underpins use cases like these, and it can help with overall system operations. Not long ago, data from a newly built, 420 megawatt (MW) gross power plant feeding a large manufacturing site showed excessive vibration and heat coming from one of the generators. The data showed that this was not normal in comparison to other systems. After a couple weeks of monitoring the anomaly, the utility shut down the power-generating equipment and detected bearing issues. The bearings had completely dried out. This discovery saved the company \$1.7 million dollars, and now managers are rolling out this analytic approach throughout the organization. That’s a win on the reliability scoreboard.

Meanwhile, all these planned solutions — AMI, FLISR, advanced distribution management systems (ADMS) and asset management tools — deliver data that can help utilities accommodate the most important application they believe they’ll need to support. That application is DER, as noted on Figure 1.

From Here to There

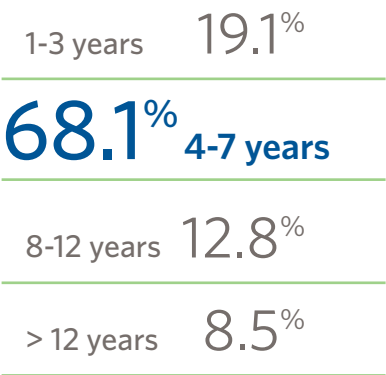
Budget constraints were one of the biggest impediments survey respondents found to implementing smart infrastructure and solutions like FLISR, ADMS and AMI. Money issues were tied with competing priorities — each was cited by 63 percent of respondents — as top barriers to modernization, and regulatory hurdles earned a vote from 48 percent of respondents (Figure 2).

Both investment and prioritizing decisions can be aided with analytics. On the regulatory side, concerns are likely tied to the uncertainty of the utility model itself. Net metering has been a bone of contention for years, with some states — Hawaii and Indiana, for example — shutting down the policy for good. Still, the downward trend in solar and storage costs are making these options more attractive than ever, particularly in areas where power prices are high. That’s decreasing the rate base for utilities to maintain infrastructure.

One large municipal utility in California is trying to even things out by imposing a fixed charge for all customers so that less revenue must be made through sales volume. Others are still looking for solutions because even with departing load, utilities must pay for wires and substations.

Figure 3

Please indicate the horizon(s) your organization uses in documenting a strategic vision for growth:



Source: Black & Veatch

Bottom line: We all know something must change. Nearly 50 percent of respondents said their future would be less regulated.

This uncertainty may be what is leading to expanded planning timelines. Years back, utilities focused on one-year rate cases. More recently, planning horizons have typically looked forward for around three years. Now, almost 70 percent of respondents are looking at four- to-seven-year planning horizons (Figure 3).

Along with emerging regulatory models, utility workers are grappling with new ways of working together. Grid automation and modernization are forcing the convergence between IT and operations technology (OT) in what has traditionally been a highly siloed work environment. Now, distribution system engineers, IT and communications experts, generation workers and operations folks work together.

A preponderance of utilities are embracing such cross-functional teams to get grid modernization done. More than half (56 percent) of respondents have the CIO, transmission, security, IT/communications and operations working together toward the smarter grid. Pull out the CIO's involvement, and you still have more than 70 percent with a strong IT/OT team on the job.

One Midwest investor-owned utility started their modernization efforts by first creating a high-level vision of what they need to look like in the future as they become a digital utility. They plan to incorporate that vision on a day-to-day basis into decisions being made about infrastructure technology and more. To oversee this effort, the utility created an independent group that is evaluating everything underway and deciding on priorities.

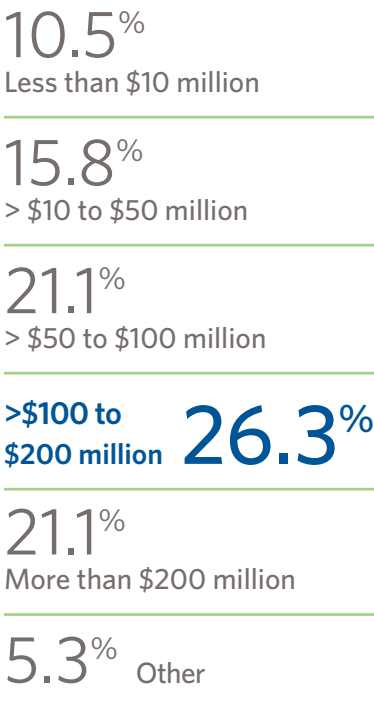
This group includes IT, generation, transmission, distribution and even customer-facing people, all of whom are on this project exclusively to be the link between the utility's vision, its daily operations and its forward-thinking technology decisions. This impressive approach is also a smart one because grid modernization will be pricey.

More than a quarter of the survey respondents are looking at spending between \$100 million and \$200 million over the next three years. Roughly one in five respondents expect to top the \$200 million price tag (Figure 4).

That's a considerable amount of money to spend — even more eye-popping when you consider that much of it will go toward accommodating DER that the utility won't even own. ■

Figure 4

How much capital do you plan to invest in modernizing the distribution system over the next three years? (Select one choice)



Source: Black & Veatch

Grid Modernization Will Require Active and Holistic Network Management

By Mark Burke

Utilities are under immense pressure in the pursuit of maximum uptime and resilience as well as enhanced power quality and lowered carbon footprints. New services are being demanded by customers and new and divergent forms of energy are testing the flexibility and capacity of their networks. Additionally, smart devices and cloud-based computing are creating and moving data in staggering amounts and speeds — all while creating numerous new pathways for cyber vulnerability.

ABOUT THE AUTHOR

Mark Burke specializes in private networks organization for Black & Veatch's Telecommunications business. Before coming to Black & Veatch, Burke was Vice President of Energy & Utility at Ericsson Inc., and before that he led the Intelligent Networks and Communications business line at DNV-KEMA, a global consulting, testing and certification organization.

Data on electric systems is gaining new attention among operators who are seeking to better understand the information flowing on their networks and how to leverage that data for reliability, security and economic benefits. Integrated smart devices and the Internet of Things (IoT) offer the promise of near-real time knowledge of the energy delivery system and heuristics for forecasting potential vulnerabilities in order to prevent outages and mitigate those that occur. With applications behind the meter, as well as down the full energy delivery chain, network intelligence strategies involving AMI, distribution automation (DA), substation automation (SA) and other technologies carry the challenge of unprecedented volumes of data about system state, asset health, customer habits, and potential cyber anomalies.

In order to capture, manage and exploit the benefits of automation, utilities are adopting telecommunications infrastructure to enable smart devices and automation systems effectively. Often these systems include multiple communications networks of multiple technologies and lineage. At the same time, utilities are faced with head count and budget constraints that require them to accomplish more with fewer resources.

Despite these advantages, it's arguable whether utilities are ready to manage and capitalize on these burgeoning connections and data flows. Maintaining the design and deployment of multiple networks — each containing thousands to millions of devices and information capture points — can often fall outside a utility's skill set, priorities or resources, even when they know it's necessary.

Figure 5

Do you expect changes in your telecommunications systems and services over the next five to 10 years? (Select one.)

16.1%

Yes, we expect changes but are not actively planning for the change

77.4%

Yes, we expect changes and are actively planning for the change

6.5%

We expect changes in the system but beyond 10 years

0.0%

No changes are expected because we've recently completed network upgrades

No changes are expected and updates aren't necessary

Source: Black & Veatch

Few scenarios capture the conundrum better than smart devices: Various communication networks of differing technologies are employed by devices to communicate with each other, from access and transport networks including radio frequency (RF) mesh and point-to-point wireless to fiber, microwave and commercial cellular. Bringing these networks together into an end-to-end network is an integration puzzle, and a necessary one at that, given that reliable communications between these often-disparate devices is crucial to their reliability.

The approach taken by leading utilities is the development of an Integrated Network Management System (INMS), serving as a “manager of managers” that allows a single end-to-end vision of all the devices and services that are being delivered by the network. It provides network surveillance, provisioning, security monitoring and controls as well as the ability to leverage telecom automating to continually learn and improve performance. Often an INMS is housed in a network operations center (NOC).

Due to resource limitations, utilities reach out to outside expert firms who can efficiently assist the utility in developing an appropriate INMS and offer supplemental or primary support for network operations. Operations support is often described as managed network services (MNS).

Utilities increasingly are leveraging experts among managed network services providers because they bring dedicated staff and deep experience at a much lower incremental cost compared to what’s required to invest in, train and maintain a dedicated in-house network management group, as utilities expand their telecommunications footprint. Nearly 80 percent of respondents to Black & Veatch’s 2019 *Strategic Directions: Smart Utilities Report* reported they expect their telecommunications programs to grow over the next 5-10 years and are actively planning for that shift, while another 16 percent anticipate change but haven’t begun planning (Figure 5).

The following are some of the factors fueling the move toward outsourced, holistic network management:

- **Proven efficiencies of moving from more traditional internet protocol (IP) routing to multiprotocol label switching (MPLS):** In conventional IP routing, the next move of a packet is determined by a router, which inspects the packet’s destination IP address — a time-consuming process that draws heavily on hardware resources and leads to diminished performance. Under MPLS, the first router can determine a packet’s entire journey at the outset, resulting in a quicker path and a smoother draw on resources.

Figure 6

How do distributed assets factor into discussions about reliable and resilient communications? (Select one)

77.8%

The increase in our distributed asset portfolio will require improvements to our communications network

5.6%

The increase in our distributed asset portfolio will not require improvements to our communications network

13.9%

We aren't planning for additional distributed assets but are seeking communications network improvements

2.8%

We aren't planning for additional distributed assets and are not seeking communications network improvements

Source: Black & Veatch

But as reliance grows on smart devices that employ MPLS, many utilities simultaneously struggle with staffing limitations, limited skill sets or workforce attrition. The challenge for utilities is often compounded by the devices themselves as many network analysis tools have varying and proprietary graphical user interfaces, operational procedures and training requirements. The deployment of massive numbers of devices has utilities thinking whether their communications applications can keep up (Figure 6).

- **Network security requirements are growing continuously:** Utilities recognize the critical role that cybersecurity plays in ensuring the future health, reliability and resilience of the electric supply. Respondents to Black & Veatch's survey continue to name cybersecurity as one of the driving forces behind modernization efforts. But the distributed nature of these projects — from the multiple site types to the sheer volume of low-impact field devices and distributed geographical nature of utility assets — raises the challenge of shutting the doors on hackers.
- **The mandate for a central view of the whole network:** Competing time and resource demands constrain the ability of utility managers to manage their networks, such as accommodating multi-vendor, multi-technology environments; and supporting end-to-end circuits, service provisioning, and performance monitoring and asset management.
- **Extreme weather:** Today's systems face seemingly constant assaults, and while the challenges presented by modernization play a large role in those conflicts, so does extreme weather. **A recent report by Utility Dive** about the U.S. Energy Information Administration (EIA) analysis of outage reports suggests, "stability may be more tied to weather and climate than modernization." The EIA found that the average duration of electric power outages nearly doubled between 2016 and 2017. The EIA blamed major storms.

It's clear that smart grids will require active network management given the grid's increasing interconnectedness. Actively managing millions of devices — many of them tied to varying transports with varying UIs and protocols — is the challenge.

The solution lies in choosing a trusted adviser with deep experience in network management services to give utilities piece of mind that this transformative approach to smarter networks will be seamless, secure and worth the investment. ■



Safe and Reliable Grid



NERC CIP Low-Impact Compliance Drives Opportunity to Improve Operational Technology Security

By Mike Prescher and Tracy Monteith

ABOUT THE AUTHORS

Mike Prescher is a network and cybersecurity architect for Black & Veatch's telecommunications business and is responsible for data network infrastructure architecture design. He has provided consultative expertise to Fortune 500 companies and utilities across North America on network design, operations and support methodology, application performance optimization and very large-scale implementation projects.

Tracy Monteith is the Director of Cybersecurity for Black & Veatch Management Consulting. He has spent most of his career in systems engineering, software engineering and project management for space systems and mission-critical systems. Monteith is a U.S. Army Cyber and Senior Space Operations Officer. He recently returned from a one-yea deployment to Kuwait and Afghanistan where he served as the Chief of Projects for the 335th Theater Signal Command under the U.S. Army Central Command G6.

The U.S. Department of Homeland Security (DHS) named cyberattacks on critical infrastructure one of the nation's most serious and potentially devastating security challenges. According to DHS, U.S. utilities face down millions of attempted cyberattacks every day. Recognizing the threat these attacks pose to the national power grid, federal regulators actively are working to strengthen protections.

For years, the primary focus was to protect the high- and medium-impact assets that make up the bulk electric system (BES). From a compliance perspective, low-impact assets (LIAs) presented less risk and therefore took a backseat as utilities focused on perceived risk-adjusted higher-priority efforts. But in April 2018, the Federal Energy Regulatory Commission (FERC) finalized a ruling of North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) reliability standard 003-7 that requires utilities to extend proper cyber protections to all LIAs on the grid by 2020, including transient assets.

The revised NERC CIP standard (Cyber Security — Security Management Controls) requires that utilities adopt consistent and sustainable security management controls that include the following:

1. Improving electronic access controls to low-impact BES cyber systems.
2. Mandating security requirements for mobile electronic devices such as thumb drives and laptops.
3. Requiring utilities to develop a response policy in the case of a system threat.

Figure 7

What is your organization's current status with regard to NERC-CIP-003-7?
(Select one)

0.0%

Planning activities have not yet begun

12.5%

Planning for LIA assessment has been completed and awaiting execution

58.3%

Assessment activities for LIAs is in progress

29.2%

Assessment of LIAs has been completed

Source: Black & Veatch

Utilities recognize the critical role that cybersecurity plays in ensuring the future health, reliability and resilience of the electric grid. Respondents to Black & Veatch's 2019 *Strategic Directions: Smart Utilities Report* survey, an annual survey of American utilities, continue to name cybersecurity as one of the driving forces behind grid modernization efforts.

However, the distributed nature of these projects — from the multiple site types to the sheer volume of low-impact field devices and distributed geographical nature of assets — makes implementing this new NERC-CIP standard an intimidating task. While the consequences of noncompliance are severe, ranging from fines to sanctions, those penalties do not compare to the chaos and damage that would result should one of these critical networks become compromised by a malevolent cyber intrusion.

Where does the industry stand in bringing itself into compliance with this NERC CIP mandate?

An Industry on the Move

According to the 2019 *Black & Veatch Strategic Directions: Smart Utilities Report* survey, utilities are working toward compliance. More than a quarter of survey respondents have completed assessments of their LIAs, and more than half are currently working on these LIA assessment activities. Thirteen percent have completed their LIA assessment planning activities and are pending execution (Figure 7).

Fifty-five percent of respondents stated their compliance work provided an opportunity to modernize their system's underlying Transmission Control Protocol (TCP)/IP data network design and capabilities. Utilities are also implementing site-based network data monitoring and protection systems such as intrusion detection systems (75 percent) and firewalls (92 percent).



Case Study

Partnering with WFEC to Achieve Compliance

Black & Veatch, in partnership with Western Farmers Electric Cooperative (WFEC), recently optimized site visit effectiveness, which is often required to complete LIA compliance. With Black & Veatch assistance, WFEC found opportunities to accomplish multiple objectives during remote-location LIA site visits. WFEC accomplished network improvements and cybersecurity upgrades in addition to LIA compliance. Initially, WFEC's task to implement LIA compliance seemed daunting. However, the project became achievable through the use of proven methods and the help of experienced Black & Veatch professionals. As the largest locally owned power supply system in Oklahoma, WFEC was determined to use this opportunity to enhance its overall security posture, not just to achieve

NERC CIP compliance. The breadth and depth of the project was significant, as it involved identifying, evaluating and protecting LIAs at 80 sites across the state of Oklahoma. The target sites included substations, pole boxes, power plants — anywhere where low-impact BES assets exist.

Together with Black & Veatch's Network Services Group, WFEC accomplished multiple cybersecurity objectives without interrupting daily energy delivery operations. At each site, the WFEC and Black & Veatch project team performed a complex evaluation and upgrade that included multiple tasks. The team established and verified cable connections, conducted a physical device inventory, conducted logical application sensing and established equipment protections. The team LIA presence enabled a rare opportunity to acquire a photo and video site logs, which are essential artifacts to demonstrate compliance and document the site's environment.



Ensuring A Successful Site Visit

While site visits are often necessary, they should be well-coordinated and controlled to minimize risks to the asset and energy delivery operations.

Utilities should employ sound visitor access control policies and procedures during site visits that include:

- Escort procedures
- Visitor badge access
- Group monitoring
- Designation of a formal floor marshal
- Coordinated network and applications access that enforce network policies

Sound change management and configuration management practices outweigh any on-the-spot optimization. So, while site visits offer tremendous potential for improvements, keeping visits short and controlled is more desirable.

Black & Veatch helped WFEC achieve three objectives:

1. Perform a site survey and inventory to identify all cyber assets and candidate BES cyber assets and include photo and video documentation.
2. Compile a per-site list of discovered data flows (including IP source and destination addresses, source and destination protocol ports and a per-site list of any unknown application flows or protocols).
3. Install and configure new LEAP protection devices at each LIA site and facilitate data flow identification that enabled LEAP protection devices to be planned, staged, configured, tested, deployed and verified.

In addition to these primary objectives, the project achieved several innovative milestones for approaching low-impact assessment project execution:

- All the physical work was accomplished in one site visit, which greatly optimized WFEC's limited resources.
- A complete picture of each low-impact site system was obtained.
- LEAP protection was implemented as appropriate for compliance.
- Low-impact logical bidirectional routed application protocol flows were identified and mapped.

Aside from ensuring that WFEC remains in compliance, the project helped strengthen WFEC's security awareness and overall cybersecurity posture at each designated low-impact site. The project armed the utility with unprecedented levels of network information, such as a better understanding of the application flow within networks. By providing a full, accurate and up-to-date inventory, both logical and physical, WFEC is now better prepared for accurate and efficient asset management.

The Future of Compliance

Considering the thousands of LIAs that require compliance and cyber protections, a plan to assess and implement compliance can seem an impossible task. However, as our team of professionals found, utilities that take a proactive stance toward LIA compliance — rather than reactive — will find themselves with the unique opportunity to not only enhance future cybersecurity protections but also build a greater level of LIA operational awareness. Although the level of work necessary to complete these LIA compliance tasks may be daunting, the site visits, inventories and documentation will arm utilities with a much higher level of operational awareness than ever before. Using this awareness, utilities can reap larger benefits for protecting and optimizing the foundation for tomorrow's smart grid. ■

Private Wireless Networks: Catalysts for Grid Modernization

By David Hulinsky

ABOUT THE AUTHOR

David Hulinsky is a Utility Telecom and Automation Director at Black & Veatch, where he provides integrated grid modernization solutions for utilities. Hulinsky focuses on advanced automation and telecommunication systems to improve the scalability, reliability and efficiency of the electric grid. He has led some of Black & Veatch's largest turnkey grid modernization projects for leading utilities such as San Diego Gas & Electric, Hydro One, CPS Energy, The United Illuminating Company and NV Energy.

The electric grid is undergoing the most significant transformation in its history, with digital technologies and devices being pushed to the edge to support dynamic, two-way power requirements in real-time while also ensuring reliability, efficiency and security.

As these digital devices approach the edge and are densified across the grid by more than 1,500 percent, utilities need an advanced wireless network that goes beyond supporting AMI and supervisory control and data acquisition (SCADA) devices that traditional Field Area Networks (FANs) support today.

A majority of the respondents to this survey say the existing field area networks they're using for AMI and SCADA will need significant enhancements to support the digital utility of tomorrow.

Now the question is: What's the right technology solution?

That's the key reason nearly 63 percent of industry respondents to the survey for Black & Veatch's 2019 *Strategic Directions: Smart Utilities Report* say the existing wireless networks they're using for AMI will need upgrades in the foreseeable future (Figure 8).

Figure 8

To what degree does your existing advanced metering infrastructure wireless network support your distribution automation needs? (Select one)

25.6% to support current and foreseeable future needs

37.2% to support current needs but upgrades will be necessary in the foreseeable future

23.3% somewhat support current needs, but upgrades will be necessary in the foreseeable future

2.3% do not support current or future needs

11.6% do not have an AMI wireless network

Source: Black & Veatch

Specifically, roughly 37 percent of respondents say the networks they have in place support current needs, and nearly one in four respondents say their networks somewhat support current needs. Only 2 percent said their existing networks do not support current or future needs, and all of these respondents see the need for changes ahead.

What are they looking for? Most are seeking a private, wireless solution for their FAN. In fact, some 43 percent of respondents strongly prefer the private option (Figure 9), and 50 percent considered public versus private to be the most important criteria for evaluating a FAN (Figure 10).

Figure 9

What are the most important criteria for evaluating a field area network (FAN)?
 (Drag and drop to rank from 1-most important to 4-least important)

	FIRST	SECOND	THIRD	FOURTH
Public vs. Private	60.5%	21.1%	15.8%	2.6%
LTE vs. non-LTE	13.2%	34.2%	28.9%	23.7%
Mesh vs. not Mesh	18.4%	15.8%	47.4%	18.4%
Licensed vs. Unlicensed	7.9%	28.9%	7.9%	55.3%

Source: Black & Veatch

Figure 10

What qualities do you prefer a field area network (FAN) to have?
 (Select one for each row)

PUBLIC vs. PRIVATE		LTE vs. NON-LTE	
Prefer Public	11.9%	Prefer LTE	47.6%
Neutral	38.1%	Neutral	47.6%
Prefer Private	50.0%	Prefer Private	4.8%
MESH vs. NON-MESH		LICENSED vs. UNLICENSED	
Mess ->Mesh	42.9%	Licensed	43.9%
Neutral	47.6%	Neutral	46.3%
Prefer Non-Mesh	9.5%	Unlicensed	9.8%

Source: Black & Veatch

Figure 11

What are the drivers for modernizing YOUR electric distribution systems?
(Select all that apply)

83.9%

Increase monitoring, control and automation capabilities

82.3%

Improve the reliability of the grid

67.7%

Improve operational efficiency and volt/VAR management

50.0%

Support distributed energy resources

48.4%

Increase customer engagement / empowerment

48.4%

Improve cybersecurity

46.8%

Network communications

Source: Black & Veatch

Bring Your Own Band

Utility systems rank at mission critical, and maintaining reliability and security of these critical assets is vital. This explains why the Utilities Technology Council (UTC) asked the Federal Energy Regulatory Commission to go beyond its own jurisdiction and work with the Federal Communications Commission on securing spectrum for utilities to use.

“For the most part, utilities have built out and maintained their own ICT networks, rather than outsourcing service from commercial telecommunications carriers,” Joy Ditto, UTC’s president and CEO, wrote in a [May 2018 filing](#). “Utilities require high levels of reliability that traditional telecommunications carriers are unable or unwilling to provide.”

Along with private networks, survey respondents showed interest in LTE — long-term evolution — networks. This is the current model for wireless cellular service and the foundation for next-generation 5G.

Among LTE’s core specifications, you’ll find downstream transmission rates up to 100 megabits per second (Mbps), upstream rates of 50 Mbps and radio access network round-trip times in the range of 10 milliseconds — speeds required for real-time data access that utilities will require to actively and autonomously manage two-way power delivery.

LTE also uses an IP-based architecture and supports a protocol that prioritizes traffic, allowing utilities to share a pipe among various devices and enable dynamic traffic engineering on the basis of latency requirements. In other words, one network supports many applications. Pushing LTE and IP to the edge will be necessary for utilities’ 4G and 5G modernization. Laying the foundation for 5G now better prepares utilities for distribution modernization over the long term. With promises of hyperspeed, low-latency and edge computing capability, utilities’ vision of efficient, autonomous and customer-centric systems is closer to reality.

The Need for Speed

Nearly 84 percent of survey respondents said they were modernizing to “increase monitoring, control and automation capabilities,” while 82 percent wanted to “improve the reliability of the grid.” Two-thirds of respondents targeted improvements in “operational efficiency and volt/VAR management” (Figure 11).

One way utilities are increasing monitoring is to deploy sensors throughout the distribution grid, including distribution-level phasor measurement units (PMUs), which have been used in transmission systems for several years.

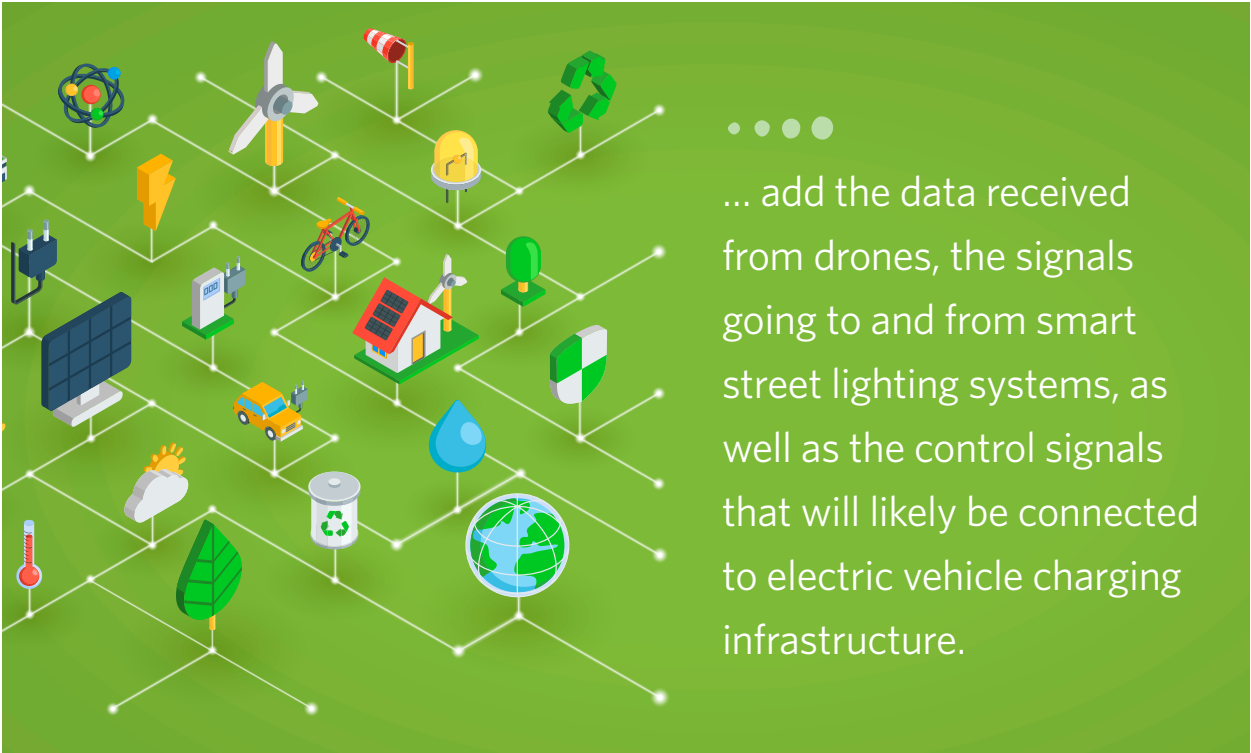


Figure 12

What are your current/future bandwidth requirements for your private wireless network?

10 Gbps or less

85.1% 36.2%

11 Gbps to 20 Gbps

6.4% 19.1%

More than 20 Gbps

8.5% 44.7%

● Current ● Future

Source: Black & Veatch

Some distribution system PMUs take readings as often as every one to two cycles, which equals 30 to 60 readings per second in a 60-hertz system such as the North American grid. The units can measure voltage, current, phase characteristics, frequency and its rate of change, switch status and more. They also have a Global Positioning System (GPS) signal embedded in them, which means that the readings can be synchronized with other readings throughout the distribution system to give grid operators a comprehensive view of grid conditions.

PMUs and all the other sensors that utilities are adding to their grids collect huge amounts of data. To this data, add in the automation signals that utilities will be sending through things such as advanced distribution management systems, fault location isolation and service restoration and voltage management technology. Then add the data received from drones, the signals going to and from smart street lighting systems, as well as the control signals that will likely be connected to electric vehicle charging infrastructure. It's easy to see why 85 percent of survey respondents are getting by on 10 gigabits per second (Gbps) of bandwidth now, but 45 percent anticipate needing 20 Gbps in the future (Figure 12).

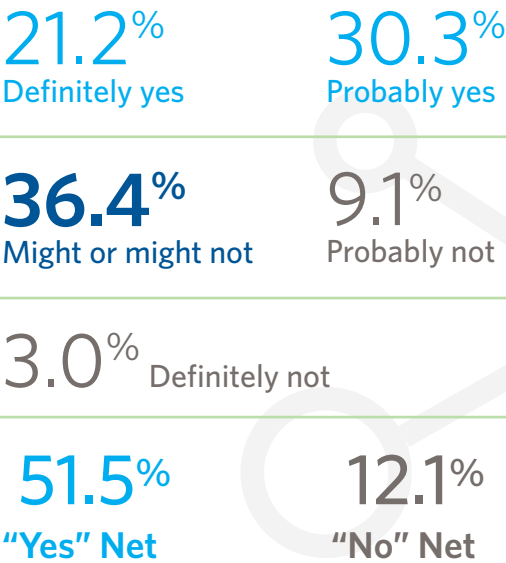
Why Private Wireless Networks?

Let’s go back and re-examine preferences for network characteristics (Figure 12). It appears that survey responses reflect utility professionals’ reality more than their wishes.

Even though half of respondents prefer a private network to support their private electric operations, roughly 8 percent named “licensed versus unlicensed” as their most important network selection criterion. This isn’t because they don’t really care if a network is licensed exclusively to them; it’s because the lack of private spectrum available today makes most utilities shrug off that preference and assume they’ll need to settle for an unlicensed option, not understanding the risks associated with the high costs to resolve the potential interference issues over the life of the unlicensed network.

Figure 13

Would your utility consider leasing spectrum for 10-20 years at market rates that could be capitalized for your private wireless network?
(Select one)



Source: Black & Veatch

Maybe they won’t.

More than half (52 percent) of respondents said they would consider leasing spectrum for 10 to 20 years at market rates that could be capitalized for their private wireless network (Figure 13). Although 52 percent say they don’t know how much spectrum they’d need, a majority will need more than 5 MHz (MHz) or greater to support their grid modernization initiatives. This might be achieved through leasing spectrum long term from spectrum owners that can be capitalized if structured correctly with the network implementation.

Ultimately, new spectrum solutions will be needed because utilities must modernize their grids to accommodate new distributed generation and other technologies. To do that, to add automation and sensing digital technology throughout the distribution system, you need a sustainable communications network that is not prone to interference and that has increased bandwidth and reliability.

Communications are the one common thread tying all grid modernization efforts together. After all, two things make grids smart: computing power and communications. Computing power won’t get you anything without the communications network in place to make data and control signals go where they need to go. ■

ABOUT THE AUTHORS

Edward A. Sutton III, P.E., is a Principal Consultant and Systems Manager for Black & Veatch. With a background rooted in critical infrastructure, he has thorough experience in leading—from concept to completion—a wide array of complex emerging technology projects. Sutton works to develop whole system solutions to complex problems focused on modernization and digital services.

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Charity Hanson is a Managing Director at Black & Veatch Management Consulting and is a member of the Business, Technology and Architecture Group where the emphasis is business transformation, enterprise asset data management, analytics for life cycle optimization, and risk and resilience. Hanson's primary interest is asset management solutions and she is responsible for the risk assessment and prioritized planning offering.

Whole-Systems Modernization: A Data-Driven Approach to Asset Performance Management

By Edward A. Sutton III, G. Scott Stallard and Charity Hanson

Driven by a desire for increased monitoring, control and automation, improved reliability and efficiency, and a need to integrate DER, utilities are working to bring a massive new array of assets online in the distribution space. The speed, scale and complexity at which these advanced systems deploy will require visualization and immersive interaction wholly unachievable with today's methodologies, paving the way for a revolution in asset management.

Historically, approaches to asset management skewed from a maintenance approach. But the energy economy is expanding, evolving to accommodate new technologies such as advanced battery storage and microgrids, growing investment in DER, an influx of high-powered electric vehicle (EV) charging networks, heightened cyber protections, the proliferation of smart systems, customer engagement platforms and advanced network communications. And as we near a 5G horizon, everything that can be connected will be.

As a result, conventional “replace and repair” asset management approaches will have no place in this future world, and are being quickly eclipsed by a more holistic, whole-systems perspective.

Building Towards a Whole-Systems Perspective

A whole-systems perspective flips the old notion that reliability is asset-centric and grounds it in a systems-centric approach. Traditional enterprise asset management is being shelved as a structural standard, a commodity that is inherently limited in the value it can unlock. Therefore, utilities are leveling up to “asset performance management,” bolting on a technological accelerator to the enterprise, which offers a smarter, more cohesive approach to managing the entire asset portfolio in a way that is analytically driven around system needs and customer benefit.

Conventional systems maintain a simple notion of criticality; advanced distribution systems recognize situation-based context, and assets and locations can and will change over the short- and long-term, altering performance in different outcomes. This provides a much more predictive and prescriptive capability.

Figure 14

Are you planning to use an asset management system to track and monitor the upgrade or deployment of your communication and distribution assets?
(Select one choice)

62.1%
Yes, we already do

29.3%
Yes, we plan to but aren't currently

8.6% No

Source: Black & Veatch

For example, context will be critical as storage and DER become more integrated. Advanced distribution systems will have to consider capacity and the ability to provision backup energy supply; different services become part of the mix and location will be a driver. To satisfy this need, it will be necessary to tie asset management system models to evolving parameters such as location, underlying circuit conditions and changing customer needs.

Data from Black & Veatch’s 2019 *Strategic Directions: Smart Utilities Report* show that utilities are on the cusp of this idea, with most survey respondents saying that they plan to use an asset management system to manage the upgrade or deployment of assets (Figure 14). This shows that these systems are being implemented across a utility’s entire array of assets, versus just the major assets, laying the foundation for a more systems-centric, agile future.

Even more profound is the compounding fact that data and the systems that manage it are pervasively growing. This begs the question of whether data can be a utility’s most valuable resource, or death by a thousand cuts.

Relationships Will Drive Value

Data underpins this effort and is the great unifier between all siloed, disparate components. Understanding the relationships and connections between the data will drive value in these systems. For example, how can you obtain full understanding unless you can model your assets in the context they are operating in? It is also necessary to understand the ecosystem in which they operate. And once you have that baseline understanding, what else can you harvest from that? How can you combine elements together in multiple ways, reuse elements in different solutions and be more efficient in the hunt for new opportunities?

Taking this systems perspective will be even more beneficial as more and more nontraditional lines and disciplines and areas of expertise are crossed, making it easier to understand how things are managed and what decisions are made. Effective decision-making will become increasingly reliant on asset intelligence at the heart of which is complete accurate, up-to-date asset records. The ability to apply context from locational perspective is something we can all comprehend and understand. As systems become more complex and integrated, how can we leverage those types of views and perspectives and communicate more effectively?

Culture as a Barrier

There is a huge amount of inertia around these systems and revamping the conventional view of asset management won't be easy. A significant culture shift will be required to convert our current physical world to a logical world and will call to mind many socio-technical aspects, such as how do you get people aligned and comfortable with this future? And comfortable understanding the power of these analytic tools that they cannot really see or feel?

Some of this will happen organically; workforce retirement will serve as a catalyst on some level. As the demographic shifts, younger generations will demand the use of technology and software-defined components, and smarter systems will replace the gray-haired systems that may have hindered progress.

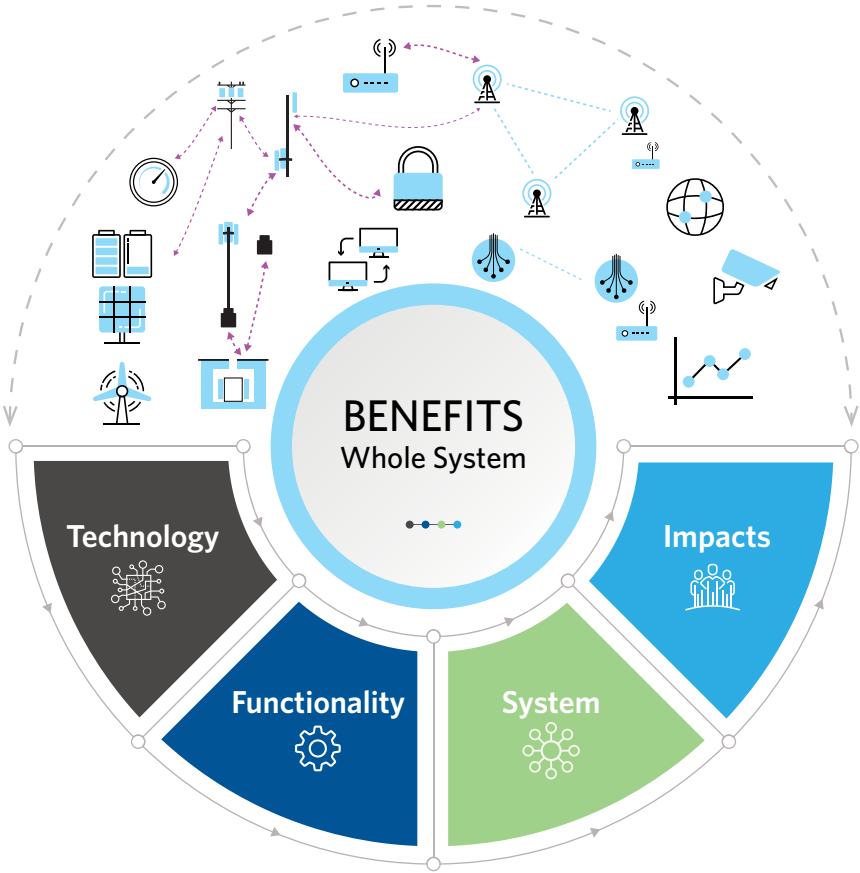
Data Makes It All Happen

Implementing this next-gen approach hinges on the quality and visualization of the data. Utilities need to focus on cleaning up and improving the quality of their data — making sure the data is structured, organized and presented in such a way that it can be consumed by an analytic and used to perform these performance management-type endeavors.

The faster utilities create this “asset golden record” in such a way that they can perform the analytics on it, the more equipped they will be to embrace these advanced systems. If not performed, the poor quality of the data will be immediately felt, and the effects will reverberate throughout these increasingly connected and integrated systems.

Whole Systems Modernization Methodology

Leverages system thinking and data-driven decision making in four foundational areas to illuminate essential and complex linkages; drives clear holistic understanding of modernization benefits and long-term value.



Frontier Beyond the Frontier

What does the future of asset performance management look like? Experts predict that 2019 will be the year of 3D visualization. Visualization innately draws upon human experience of understanding highly complex scenarios. We'll see movement away from static, two-dimensional presentations and towards immersive environments.

Artificial Intelligence (AI) and adaptability, along with the evolution of the user experience, will become more relevant, convenient and flexible. Visualization will reign supreme, as LiDAR and similar technologies help build this digital twin of the physical world, converting reality into something analytically viable. The future is cloud-based as data is digitized into a digestible format and can be displayed in the literal palm of a hand.

The result? Endpoints that are more purposeful and tailored to user experience, risk and system design, locational issues, quality and condition.



Predictive Analytics Bring It Together

Whole-systems modernization will involve programs and projects that are executed on a very large scale, producing tremendous amounts of project, asset and systems information. To manage and visualize this complex data, Black & Veatch relies on a tool called "project management", which helps utilities deploy large-scale grid modernization projects. Powered by ASSET360®, the cloud-based analytics platform offered by Atonix Digital as Black & Veatch's software subsidiary, program management serves as a central hub that provides real-time views into a project's status and performance.

By providing a single point of reference for activity management, scheduling management, productivity, etc., program management offers up-to-date awareness as it integrates with other capabilities of ASSET360® to paint a picture of risk, risk assessment, systems thinking, system models, performance analysis, monitoring and diagnostics, and the detection of systems or assets failure. Tools such as these will be a critical part of any modernization effort.

Building the Future State

To some degree, fully embracing whole-systems modernization and asset performance management solutions will be a process of evolution. The elements are there (models and analytics), but gaps remain until the future state becomes reality. For example, you cannot build a full-blown tool set that analyzes DER at heavy level of penetration until that level of integration becomes reality; only then will we have the real-world data and experience to build that capability.

We are entering new territory, and for forward-thinking organizations, the immediate returns on investment can be quite large. To this point, workflows have been predictable, and distribution was a relatively straightforward one-way flow of power to the consumer. But the future is highly dynamic and things are changing very quickly, forcing the utility to keep up. ■

ABOUT THE AUTHORS

Pat Rush is a Solution Architect and Consultant for Black & Veatch's Management Consulting business. He has 25 years of IT experience, including 19 years of utility industry experience. Rush's technical, functional and managerial experience spans the full life cycle of smart metering and customer information system (CIS) development, with a focus on advanced metering infrastructure.

Stuart McCafferty is a Managing Director focused on DER integration for Black & Veatch Management Consulting. McCafferty, who recently published "DSO Models for Utility Stakeholders," is a NIST fellow for Community Resilience, an industry expert for Energy Central and vice chair for OpenFMB User's Group. He previously served as VP EnergyIoT at Hitachi and was VP of Operations for the Smart Grid Interoperability Panel.

Forrest Small leads the Growth and Performance practice of Black & Veatch's Management Consulting business. He is responsible for thought leadership, solution development and go-to-market strategy for the division's offerings in infrastructure modernization, DER integration and new energy. Small is a licensed professional engineer with 27 years of combined experience in management consulting, as well as T&D planning and operations at an electric utility.

Heather Sanders is a director in Black & Veatch's Management Consulting business. She is a recognized thought leader serving as a member and advisor in forums focused on enabling technical capabilities, business model and policy changes. Sanders' experience spans electricity industry domains, including distributed energy resource integration, grid modernization, wholesale markets, and distribution and transmission planning.

Is the Energy Market Finally Ready For DER?

By Pat Rush, Stuart McCafferty, Forrest Small and Heather Sanders



A few years from now, perhaps some would argue this is already the case, the next generation will look back in perplexity at a time when record companies and radio stations had one-way control over distributing music to the masses. A statistically significant portion of the population will have no recollection of a world that had little control over what music was being supplied, and no choice but to trust that the service they were receiving had their best interests and tastes in mind.

A few generations from now, we may be saying the exact same thing about another culturally significant commodity — energy.

Similar to the way that music services like Spotify and YouTube give artists a platform to share and monetize their product without the oversight of a record company, a DER marketplace can have the same impact on our electric grid. By offering an avenue for energy created and stored behind-the-meter to be supplied to consumers without the direct oversight of Transmission System Operators (TSOs), DER supports innovation and the propagation of cleaner, more efficiently allocated energy.

While record companies still exist, as will TSOs undoubtedly, demand for a more egalitarian market commensurate with the times is on the rise as we look to leverage available technology and better serve the customer.



...investors will be more motivated to generate, store and monitor their own power if there are mechanisms in place to sell what they don't use.

Distribution System Operators Play Pivotal Role

It's no secret that common DER applications such as rooftop solar, on-site batteries and smart thermostats are rapidly gaining adoption across the country. As the desire to address climate change issues surges on, an evolved market that capitalizes on new ways to generate, store and monitor power is inevitable.

No longer is energy being solely generated and distributed in a one-way direction. Energy, just like music, can now be generated from (nearly) anywhere and by (nearly) anyone. The question is, do utilities have the mechanisms in place to ensure the DER revolution will play them a favorable melody? And if not, what can they do to position themselves for success?

Enter the Distribution System Operator (DSO), a vital set of roles for operating, managing and when necessary, developing an energy distribution network that integrates DER and a marketplace for trading energy. States like California and New York are proactively implementing DSOs because, to put it bluntly, DER penetration is impacting business. And because regulators and customers demand lower costs and greater efficiencies, utilities are being pressured to use DER and need an entity to operate them and create an open and transparent marketplace for DER owners to participate.

Unlike a TSO or an Independent System Operator (ISO), a DSO is not necessarily a standalone organization. DSOs operate as a conglomerate of roles across a variety of organizations. These roles include Distributed Energy Resources Managers (DERMs), grid operators, market operators and short-term and long-term planners, all acting in harmony to address this new two-way player in the market.

Establishing a DSO creates a market for anyone owning DER to monetize their investment. Simply put, investors will be more motivated to generate, store and monitor their own power if there are mechanisms in place to sell what they don't use. The manifestation of a DER market will lead to increased penetration in a region or community by further incentivizing their use and opening opportunities for greater innovation.

The "why DSOs?" question is clear, but what about the "how?"

Many players in the distribution space are currently working to find the answer to this question. Black & Veatch recently partnered with a Southern California utility to guide them through the following six steps as they work to successfully implement a DSO:

1. Figure out where your utility is currently situated, and when DER impact will be felt

Figure 15

How many customer programs does your utility currently provide for DER (demand response and/or distributed generation)?

PERCENTAGE	PROGRAMS
5.9%	0
15.7%	1
23.5%	2
21.6%	3
3.9%	4
5.9%	5
23.5%	>5

Source: Black & Veatch

- 2. Determine which processes will be impacted by high-penetration DER
- 3. Interview and educate key stakeholders about DSO
- 4. Provide stakeholders with a detailed breakdown of the DSO options
- 5. Ideate in a workshop to create a functional DSO model
- 6. Consolidate ideas and model to create an actionable implementation and operation strategy

A DSO that is uniquely constructed to manage a utility’s DER situation gives that utility the tools necessary to increase DER adoption and diversify the way in which the market generates and delivers its power.

DER Programs Lead to DER Profitability

Growing adoption and penetration has made DER an intriguing prospect for utilities. Although challenges exist, a viable DER marketplace offers untold opportunity. When DER first appeared, a variety of programs were implemented by utilities to leverage new technologies and better serve customers. According to results from the *2019 Strategic Directions: Smart Utilities Report* survey, 30 percent of utilities currently provide five or more DER customer programs (demand response and/or distributed generation). A mere six percent said they offer no programs, while less than 16 percent only offer one.

Customer programs that offer critical peak pricing and incentives for using energy efficient appliances and thermostats have long been the primary extent that utilities engage with DER and served as tools to shape behavior and shift load demand. A desire for higher reliability, better resiliency, and lower energy costs is driving DER integration into the system and utilities must figure out how to effectively operate a new two-way system in which investors of DER can profit off their purchases by selling power to willing buyers.

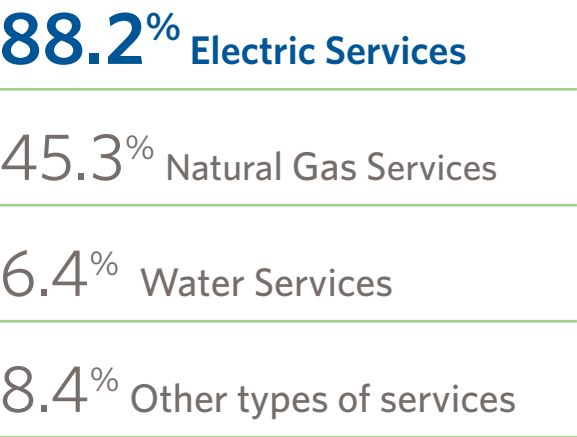
With the price of solar on a steady decline, localized artificial intelligence right around the corner, and if legislative mandates from California and New York are a sign of things to come, there’s no denying that more DER investments are on the horizon and that animating the DER distribution market is the logical progression for the industry.

Establishing a DSO will create open and transparent market enablement for anyone that owns DER, and huge opportunities for innovation and an ability to monetize your investment. This is the next thing in our new world of energy, and once it happens, everything we knew about the energy market will be put on shuffle. ■

2019 Report Background

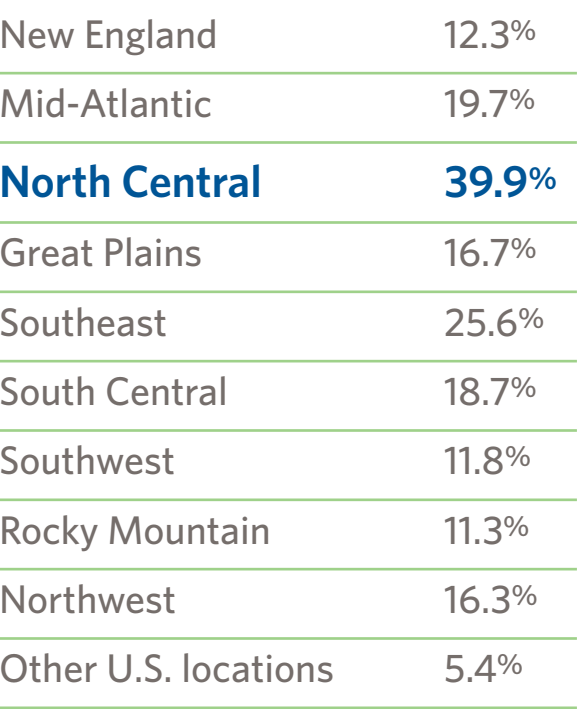
INDUSTRY TYPE

Which, if any, of the following utility services does your organization provide?
(Select all that apply)



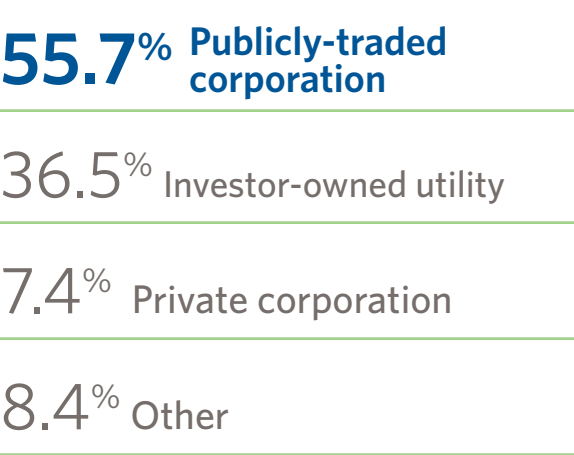
PRIMARY BUSINESS REGION

In which regions of the United States is your organization located and/or provide services?
(Select all that apply)



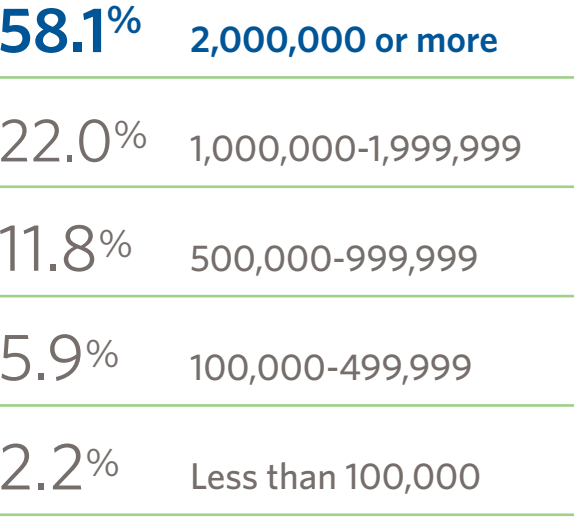
OWNERSHIP TYPE

Which of the following categories best describes your organization's ownership type?
(Select all that apply)



POPULATION

What is the estimated population served by your organization?
(Select all that apply)



JOB FUNCTION

What job function do you currently hold within your company? *(Select one choice)*

43.6% Director, Supervisor or Manager

24.3% Engineer or Operator

12.9% Other

9.9% Consultant or Analyst

5.0% Executive or Government/ Municipality Leadership

4.5% Business Development or Marketing

"SMART CITY" INITIATIVES

What role is your utility playing in your municipality's "Smart City" initiatives? *(Select one choice)*

43.8%

We are playing a leadership role beyond that of just a participant, helping to advance and define "Smart City" initiatives

32.8%

We are playing a support role, as a participant in "Smart City" initiatives

23.4%

We are not involved in "Smart City" initiatives

	2017-18	2018-19
Leadership Role	24.0%	43.8%
Support Role	41.9%	32.8%
Non-Involved	34.1%	23.4%

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