Investing for the Future

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IT IS NO SECRET THAT THE ELECTRIC POWER distribution industry is in the midst of unparalleled disruption. From the continually evolving development of renewable energy sources to catastrophic storms to an onslaught of incoming data, utilities are being forced to adapt to even more change and issues requiring resolution than they have seen in a century, which include the following:

- ✔ an escalating number of severe weather events sharpening the focus on increasing resiliency
- ✔ requirements for greater interoperability between systems and devices due to the rising adoption of distributed energy resources (DERs)
- ✔ achieving appropriate operational performance and financial returns for grid modernization initiatives, including digital transformation.

Municipalities and cooperatives are uniquely impacted by these forces based on their business and operational models. Their customers expect the same level of service and uptime as that provided by larger utilities. They are at the mercy of the same weather events and under the same pressure to diversify energy sources to reduce environmental impact. Because of their smaller size, however, they have fewer resources and greater budget constraints impacting their responses to these pressures.

This is not to say that small utilities are not keeping pace; rather, they are leveraging various creative options to overcome these challenges using techniques such as the following:

- ✔ obtaining funding and prioritizing initiatives with the greatest return
- ✔ ensuring a consistent knowledge base across stakeholders through documentation, digitization, and training
- ✔ automating activities to make small teams more productive
- ✔ ensuring interoperability between system and operational applications to share data for maximum effectiveness and productivity.

Using three real-life case studies of U.S. cooperatives, this article illustrates how smaller utilities can overcome challenges to meet their goals. Each utility profiled is in a different stage of the advanced distribution management systems (ADMS) journey:

- ✔ *Case Study 1*: The co-op utility featured in this case study has completed its ADMS implementation and has been running a supervisory control and data acquisition

Digital Object Identifier 10.1109/MPE.2019.2947817
Date of current version: 7 January 2020

How Small Utilities Are Finding Success With Advanced Distribution Management Systems

(SCADA) system; fault location, isolation, and service restoration (FLISR); and other distribution management systems applications for many years. This case study discusses the following results achieved by the utility:

- a decrease in the System Average Interruption Frequency Index (SAIFI) of 32%
- a nearly 50% decrease in the System Average Interruption Duration Index (SAIDI)
- 20% less time spent by field crews on outage repairs.

The case study reviews how the utility was able to increase employee confidence in ADMS applications and quickly train operators and other users. It also shares lessons learned to help other small utilities install an ADMS successfully.

✔ *Case Study 2*: This case study profiles a utility that is just beginning its ADMS journey. It wants to use a SCADA system to control DERs. To make the project affordable, it has partnered with a government entity on a project to evaluate models for integrating grid-friendly DERs. The case study assesses the utility's motives for enacting an ADMS, the required initial work, and its advice to utilities on funding and prioritizing ADMS projects.

✔ *Case Study 3*: This case study features a utility halfway through its ADMS journey. Due to the terrain, 20% of its distribution lines must be overhead with exposure to vegetation, which causes outages that can trip both overhead and underground portions of lines. The utility first upgraded its SCADA system to an integrated ADMS platform and applied FLISR to gain reliability improvements through automation. This case study discusses the infrastructure required to enable the ADMS, the importance of interoperability and platform selection (see Figure 1), lessons learned, and the value the utility has seen, to date, with its implementation.

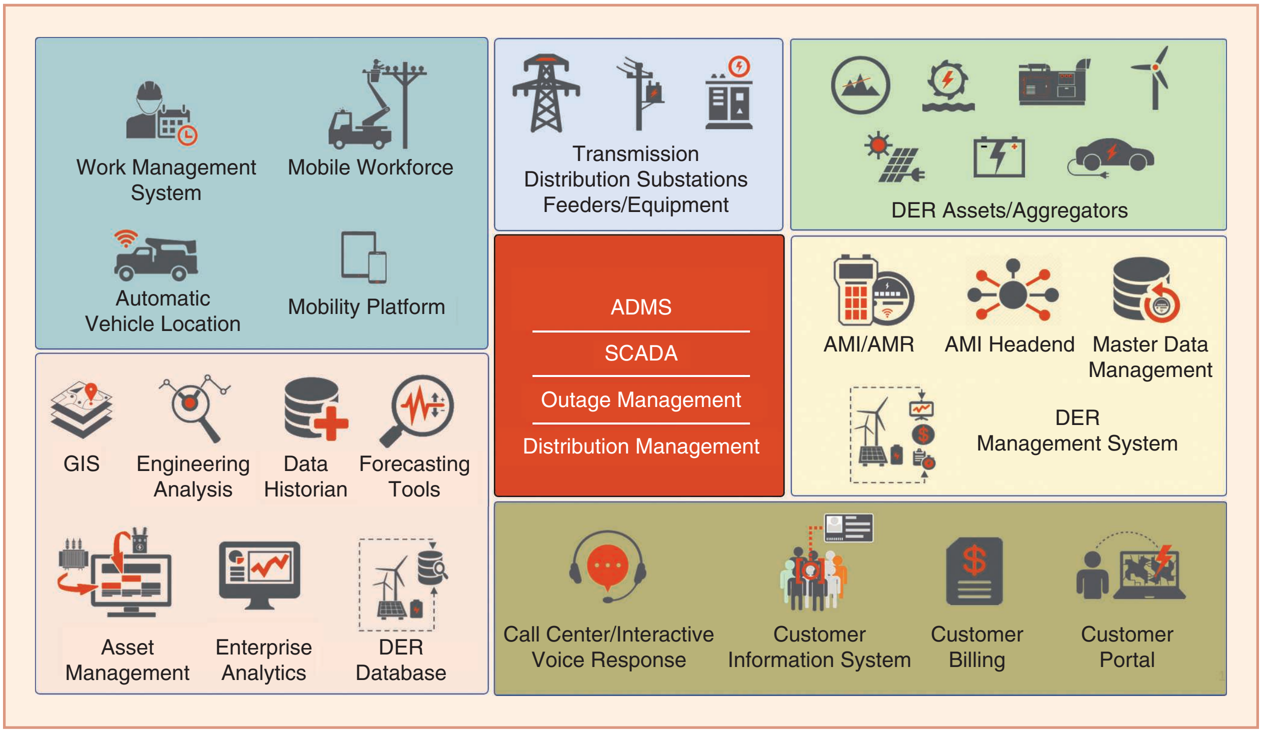

figure 1. ADMS applications exchange data with a multitude of devices and systems. GIS: geographic information system; AMI: advanced metering infrastructure; AMR: automatic meter reading.

Objective 1: The Escalating Number of Severe Weather Events is Sharpening Utility Focus on Increasing Resiliency

For small rural utilities with widespread territories and diverse terrain, resiliency requires an investment in automation. The reason is simple: When an outage occurs, personnel may need to drive hundreds of miles to identify the cause and deliver the necessary resources and equipment to perform outage restoration. In addition to the burden these issues place on the utility's finances and resources, this can also tremendously affect reliability and outage durations.

Despite the challenges to utility operations, today, customers in all locales have high expectations for reliable electric service and communication of outage restoration status. Utilities must improve their SAIDI rates and make certain that customers have increased awareness of outages, estimated restoration times, and the work being done to ensure reliable service. To accomplish these goals, smaller utilities are investigating the use of outage management and distribution management applications, which can be used to reduce outage times, share real-time information among internal stakeholders, better manage customer communications, and empower field crews to undertake restoration activities quickly.

Case Study 1: Lessons Learned From Central Georgia Electric Membership Cooperative

Utility Spotlight

- ✔ *Who*: Central Georgia Electric Membership Cooperative
- ✔ *What*: a nonprofit electric distribution cooperative
- ✔ *Where*: Jackson, Georgia
- ✔ *Territory*: dense suburban and rural areas in parts of 14 counties
- ✔ *Number of customers*: 58,000 residential, commercial, and industrial customers.

The state of Georgia is prone to storms and high winds that can cause devastating damage to homes, schools, and businesses. The Central Georgia Electric Membership Cooperative (EMC) realized that critical changes were needed to increase its service reliability, as a very small number of outages contributed to the majority of its outage time. After benchmarking and analyzing the outage durations and restoration solutions of its peers, Central Georgia EMC recognized that its outage durations were at an unacceptable level and decided to invest in digitization and automation to upgrade its grid.

Central Georgia EMC began by updating its SCADA system with a solution delivered on an integrated ADMS platform. A core characteristic of the ADMS was a model-based, centralized FLISR system that used real-time data from the network to make a quick and accurate diagnosis, identify the best network reconfiguration, isolate the damage caused by the fault, and restore power to customers upstream and downstream of the faulted area.

Using FLISR, Central Georgia EMC could quickly restore service to the majority of customers, dramatically reducing its outage durations. The chosen FLISR solution was subjected to in-lab, scenario-based testing prior to the full launch of the system to correct any technical or operational issues before going live. The utility loaded distribution system models into the test application and simulated scenarios, resulting in an automated response from the system. Testing each scenario ensured that the FLISR system would correctly interpret data from the devices in the field and make the right decisions. This also enabled Central Georgia EMC to identify and correct any deficiencies in the network model prior to commissioning the system.

In addition to FLISR, the following strategies were deployed by Central Georgia EMC:

- ✔ *A protection settings manager*: This guarantees the correct protection settings are used after any network reconfiguration, such as a FLISR event. It monitors the grid and updates selected relays through an automated, rules-based process, which makes certain that the correct settings group is always active. This reduces the likelihood of cascading faults occurring in the network, which results from miscoordinated protection systems and, consequently, decreases the potential for outages.
- ✔ *Distribution power flow*: This computes and presents phase voltages, currents, and losses to the entire distribution network. The enhanced visibility helps Central Georgia EMC detect system problems, including overloads and voltage violations, and optimizes system operating efficiency.

For Central Georgia EMC, system interoperability was an important factor in rapidly improving the effectiveness of operators. Operators were already facing the challenge of learning new applications that use complex technology, so forcing them to toggle between applications to interpret system events and choose the appropriate action would only result in valuable time lost. Interoperable systems established that system operators had real-time intelligence across all platforms for optimal decision making.

In addition to training operators, Central Georgia EMC used scenario-based training to demonstrate the benefits of FLISR, the protection settings manager, and distribution power flow applications to other employees, including field personnel. The applications dramatically changed the utility's event response processes. To mitigate concerns from operators about the impact of automation on its processes, Central Georgia EMC first introduced remote-controlled, pole-mounted reclosers that were manually operated from the control center. This incremental approach helped operators increase their confidence in the new technologies.

Scenario-based training for all employees was also key for the general acceptance and use of FLISR, particularly by field personnel. The training clearly demonstrated the potential benefits for a range of situations and helped develop consistent organizational expectations for this automation technology.

> Since putting FLISR into place, Central Georgia EMC has greatly improved its resilience and reduced the time it takes to restore service to customers.

Results

Since putting FLISR into place, Central Georgia EMC has greatly improved its resilience and reduced the time it takes to restore service to customers. Hurricane Irma, in 2017, was the utility's first real test of its ADMS. It was the primary platform used to organize the restoration effort during the first 24–36 h of the storm. The utility used FLISR in automatic mode throughout the storm and noted several instances in which FLISR responded, and the field crew took corrective measures to restore power to the area, with subsequent storm conditions causing FLISR to activate again in the same area. At the height of the storm, approximately 60% of its customers were without power. The real-time, concise nature of the ADMS data enabled Central Georgia EMC to understand the nature of the outages affecting the system and determine the amounts and locations of resources to be deployed during the early stages of the restoration effort.

Since unifying its ADMS platform, Central Georgia EMC has made significant energy distribution and operational efficiency improvements. The cooperative saw its SAIFI fall by 32% in the first year of FLISR operation, and the SAIDI also decreased dramatically. Prior to its FLISR implementation, Central Georgia EMC's SAIDI was 130 min, but two years later, it decreased to 65.8 min. The utility estimates that field crews now spend roughly 20% less time restoring outages, which has improved productivity during normal business hours and reduced overtime costs.

Among the intangible benefits of Central Georgia EMC's ADMS implementation is the cultural shift toward innovation throughout the organization. The successful adoption of automation through FLISR has provided opportunities throughout the organization to consider new and innovative ways to improve utility operations and build value for customers.

Lessons Learned

Perhaps the primary lesson learned by the ADMS implementation is the value of starting small. The utility started by operating communications systems with capacitor banks and a few pole-mounted reclosers several years prior to initiating the full FLISR project. Its engineers were therefore able to ensure they had a good communication network, and the team developed confidence controlling the power network remotely. The utility continued building trust in new technology with small successes, gradually adding to its capability and knowledge base until it was ready to initiate a complex, sophisticated project, such as FLISR. As a result of investing the time to apply early lessons learned, Central Georgia EMC was able move much faster on the back end of the project.

The utility also learned to be innovative in deploying resources. Central Georgia EMC addressed resource limitations by identifying the potential time savings achieved through process improvements. From engineering to testing and commissioning of apparatus to construction and postimplementation, all processes were closely examined. The efficiencies gained empowered the utility to commit sufficient resources, with some contract support, for the FLISR implementation. Although the utility examined the FLISR installation and its associated field equipment as a special project, Central Georgia EMC also identified operational efficiencies that could be achieved through revisions to operating practices.

Objective 2: Addressing the Requirements for Greater Interoperability Between Systems and Devices Due to the Rising Adoption of DERs

The century-old system of centralized power generation, with one-way power flow from the transmission network to the distribution system serving end consumers, is transitioning to a decentralized electrical grid network (see Figure 2). The driving force is the demand for DERs and the decreasing cost of renewable energy. Large and small utilities must prepare for integration of DERs at the grid's edge, whether they be in the form of customer-owned solar panels, utility-owned wind and solar plants, electric vehicles, or other emerging technologies.

The large amount of data introduced by digital transformation has increased the need for interoperable applications, which becomes even more critical as utilities adopt high levels of DERs. Advanced applications will need to share data to expand situational awareness of the system, generate comprehensive data analytics, and allow utility operators to coordinate with grid-edge assets. In addition to satisfying customer demand for energy options and regional/jurisdictional requirements for clean energy, DERs can support the operational performance of the grid for peak management, voltage regulation, frequency response, spinning reserves, and system optimization.

The downside for smaller utilities is the cost and risk involved with integrating distribution system operations with DERs in the grid. Utilities must see to it that grid operators have access to timely data on the quantity of electricity being fed into the grid by the DERs. A lack of information due to poor system interoperability can lead to the uncoordinated management of centralized and distributed generation sources. This, in turn, can negatively affect system stability, reliability, and electricity costs (see "Minimizing the Knowledge Gap").

When upgrading software or integrating new applications of ADMSs, small utilities should focus on the following aspects:

- ✔ the protocols and standards that can be used to communicate and exchange data with other enterprise systems, field equipment, mobile workforce solutions, and analytics programs
- ✔ the value of an integrated ADMS platform that allows utilities to add applications over time, in an evolutionary manner
- ✔ the ease and cost-effectiveness of maintaining these systems over time and minimizing the barrier for interoperability (see "Interoperability in Action").

Case Study 2: Lessons Learned From Holy Cross Energy

Utility Spotlight

- ✔ *Who*: Holy Cross Energy
- ✔ *What*: a nonprofit rural electric cooperative
- ✔ *Where*: Glenwood Springs, Colorado
- ✔ *Territory*: Western Colorado
- ✔ *Number of customers*: 43,000 members and their communities.

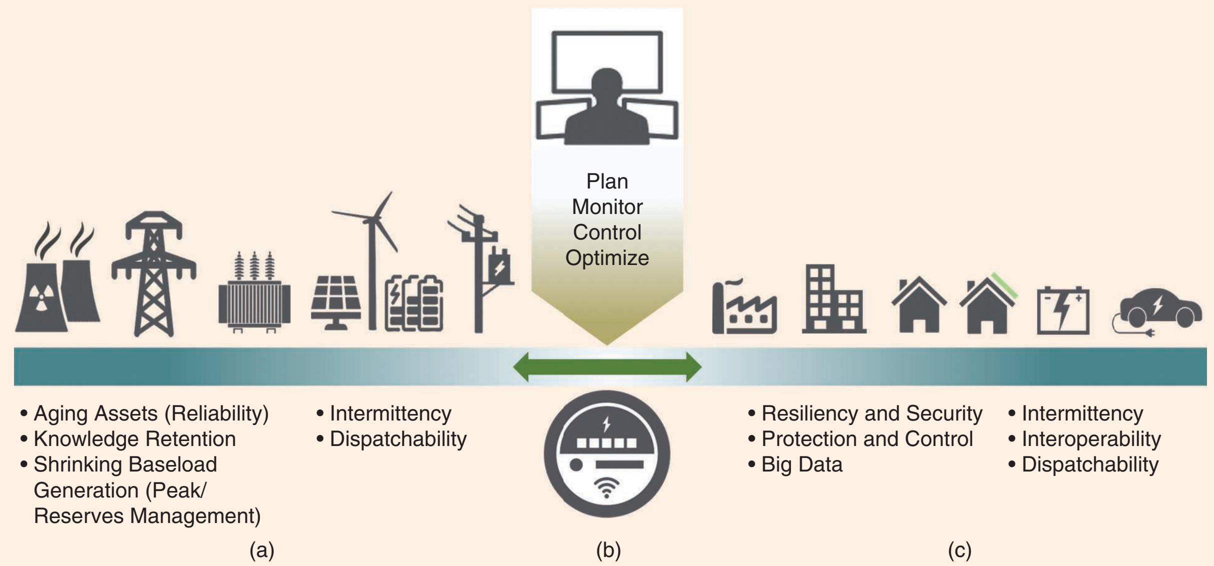

figure 2. Utilities must find an energy balance between (a) traditional forms of generation, DERs, and distribution networks and consumer demand and (c) the two-way power flow of consumer-generated DERs, all while addressing the challenges of each. (b) The distribution utility plays an important role in merging the past with the future.

Minimizing the Knowledge Gap

In addition to improving stability, reliability, and cost control, observability and data sharing play a role in minimizing knowledge gap issues that can arise as key personnel retire. Utilities see a greater return on investment when data are shared easily among infrastructure, applications, and people and when applications have complete visibility of the grid and the data needed to automate activities. For optimal effectiveness, utilities must have a bidirectional data exchange between devices in the field and the control room as well as the ability to exchange data across operational and information technology systems in near-real or real time.

Interoperability in Action

The Pacific Northwest National Laboratory is working on a multiyear program funded by the U.S. Department of Energy called *GridAPPS*. This program evaluates open-source platforms and infrastructure that can help utilities and vendor communities build interoperable applications for advanced distribution management system solutions. The objective is to minimize the system's implementation and integration efforts and maximize the interoperability between different vendors' solutions to meet the operational needs of the utilities.

Holy Cross Energy (HCE) is in the early stages of its ADMS implementation. Ultimately, the utility aims to increase its grid reliability, improve power quality, increase its use of renewable energy resources, secure data, and become more resilient to natural disasters.

HCE views its grid modernization initiative as a tool to balance the values of its members. In some cases, members want maximum reliability for the lowest cost possible and are unconcerned about the sources of electricity. Other members are eager for renewable energy options, even if this puts upward pressure on costs. HCE realized it would need to innovate to incorporate more DERs and manage load using the same dexterity with which it has managed supply. An ADMS system was used to perform the necessary calculations and commands.

To date, the utility has used its SCADA system to monitor power flows and voltages at substations and reclosers, examine real-time data, and increase utility control over assets, including renewable energy sources. HCE has also deployed SCADA control of DERs and is using short-term load forecasting software to help manage and predict system loads. HCE sees a need for short-term load forecasting to take advantage of the synergy between renewable energy and flexible loads, including plug-in electric vehicle charging. The utility can leverage its awareness of periods prone to renewable oversupply to optimize consumption management. HCE also uses short-term load forecasting to send real-time load data to its energy services provider.

The ADMS will need to integrate current data, measurements, and control applications from a variety of vendors. The utility plans to operate the ADMS from a single, centralized platform that will facilitate the seamless addition of new applications. Without the ADMS, HCE's operators would be forced to use multiple, noncentralized, cloud-based platforms to control behind-the-meter (BTM) DERs. Navigating multiple proprietary software interfaces to accomplish a coordinated objective is inefficient and convoluted. HCE decided the best way to develop a long-term DER strategy was to prioritize the installation of a unified platform that would aggregate all measurements and allow for fast and accurate decision making.

Although the utility was confident in the idea of improving visualization and system control, it faced challenges in funding the project and assigning resources from its relatively small team. Because HCE is a small cooperative, employees have to be nimble, i.e., able to perform multiple tasks using diverse skills. The utility does not have a dedicated SCADA/ADMS role, so system management is just one of the many functions taken on by team members who also manage the geographic information system (GIS) and system operations.

To address these challenges, HCE applied for a U.S. Department of Energy High Impact Technology Project. The National Renewable Energy Laboratory (NREL), the National Rural Electric Cooperative Association, Heila Technologies, Survalent Technology, and HCE are identifying the requirements and means to achieve ADMS and DERs interoperability. Specifically, the project aims to enable smaller utilities to incorporate DERs at scale into its distribution network.

The collaborative project will identify algorithms and communication protocols that small utilities can use to monitor and control DERs without requiring expensive investments in new technology to achieve interoperability. The project will test the integration of new algorithms and communication protocols with legacy and advanced applications to provide real-time grid services and increase DER hosting capacity. To ensure efficient performance in real-life operating scenarios, advanced control algorithms will be evaluated using data from HCE's distribution management system. The project will assess use cases in a realistic environment, which includes megawatt-scale hardware testing in the lab and the 250-kW field deployment testing of HCE's system.

HCE has been preparing for grid modernization in small stages for years. It began with the use of a GIS, the subsequent installation of smart devices on reclosers and voltage regulators, and HCE is now deploying line sensors, automated switching equipment, and distribution monitoring meters that utilize Distributed Network Protocol 3. Potential next steps include installing local coordinators on switchgears or transformers that will manage BTM (or even become the meter) and using aggregators that will make DERs more flexible.

The utility has also established three new tariffs: a DER service agreement to help with the upfront cost of installing DERs, a peak-time rebate program for individuals who wish to control their own energy usage in exchange for incentives during peak events, and a distribution flexibility program for members who are willing to let the utility optimize and control their DERs.

As a result of the DERs interoperability project, HCE hopes to add more load flexibility controllers for load deferral and demand-response applications. These will help manage peak loads by deferring energy usage and dispatching storage devices integrated with renewable energy supply. The utility is also encouraging the establishment of residential nanogrids to make communities and homes more resilient, efficient, and flexible. Future plans include the application of a BTM battery management system and load control breakers. Examples of flexible operations provided by very small, locally controlled systems include the option for a flattened load shape, coincident peak minimization, or storage-use optimization for microgrids or broader system resiliency.

Collaborating on this research will help the utility overcome the financial and resource challenges of enacting DERs and also will reduce the financial and project administration risks. HCE's ability to perform testing in the U.S. Department of Energy's primary laboratory for renewable energy and energy efficiency research prior to implementation in its own grid has enabled the pilot field deployment to run smoothly from the start.

Lessons Learned

The collaboration between HCE and its partners is an excellent example of multiple stakeholders working together for mutual benefit and maximum value. Initiatives like these can help offset the cost for smaller utilities. Although there may be initial uncertainty concerning its benefits, the return on investment for executing an ADMS system is clear, in HCE's experience. For example, NREL studied the impact of DERs on HCE's system. The study found that, compared to a base case in which there was no aggregated control of DERs, electricity costs for all-electric residential consumers could be reduced by 20.7% when ADMS-controlled DERs were combined with a time-of-use rate. This would also reduce local impacts on the distribution grid. It can also be difficult to justify the ongoing cost, but once the system is up and running, the positive impact on resilience, reliability, and renewable energy options can be positive by comparison. Applying for a grant or participating in a research project can offset some of the cost, but for a smooth and successful project, consumers or members must see the benefits and support the initiative.

HCE advises other small utilities to think big but start small and be patient. Utilities should first build a foundation of validated data and a good system model and then integrate that information for better system visualization and system awareness. Once these foundations are complete, utilities can comfortably add applications such as switching validation, outage restoration, and forecasting. Using these applications, utilities can establish a system capable of controlling segmented microgrids that alternate between local optimization and participation in broader regional optimization.

Objective 3: Achieving Appropriate Operational Performance and Financial Returns for Grid Modernization Initiatives, Including Digital Transformation

Unprecedented advances in technology and new levels of customer empowerment are introducing new devices and software capabilities, which are accompanied by higher customer expectations. From smart meters to cloud-based software to enabling the use of mobile devices to distribution automation and more, the industry norm is moving inexorably toward a smart grid. Small utilities are not exempt from the need for grid modernization.

Just as grid modernization is inevitable, the advancement of digital transformation into every aspect of utility operations is equally relentless. Every new device, application, and piece of hardware is designed with the digital consumer in mind, be they human or machine interface.

This puts an additional burden on decision makers to identify, prioritize, and budget for a capital investment plan that aligns infrastructure and software with long-term goals. Utilities must address the requirements of regulators, commercial customers, and residential consumers. To further complicate matters, they must also balance technology investments with systems and human resources at a time when a greater number of employees are retiring than being hired.

The tasks ahead may seem daunting, but the financial and operational rewards of embracing grid modernization and digital transformation are clearly helping utilities to accomplish the following:

- ✔ improve decision making, resulting in more resilient and reliable power delivery
- ✔ increase customer satisfaction by providing access to online interactions and information
- ✔ attract and quickly provide the incoming younger workforce with a modern user experience and automation capabilities
- ✔ increase productivity and decrease outage durations using applications that automate outage detection and restoration activities.

Vendors can help utilities determine the technology that will have the most impact in the right areas and build an affordable road map that delivers the greatest overall return on investment. To do so, utilities must select vendors whose product development plan is in sync with their needs, partner with them over the long term, offer advisory support, and support them in achieving their goals.

Case Study 3: Lessons Learned From Peninsula Light Company

Utility Spotlight

- ✔ *Who*: Peninsula Light Company
- ✔ *What*: the second-largest member-owned cooperative in the Northwest United States
- ✔ *Where*: Western Pierce County, Washington
- ✔ *Territory*: 290 km^2, including rugged terrain
- ✔ *Number of customers*: 32,000 residential and business electric consumers and 3,230 water consumers.

Peninsula Light Company is halfway through its ADMS implementation plan, having begun that effort in 2016. It was part of an ongoing reliability improvement commitment made by its chief executive officer and board of directors in 2005. Its ambitious goal was to move from the fourth quartile of reliability to the first quartile, as compared to all U.S. utilities and using IEEE reliability benchmarking.

In 2009, Peninsula Light Company redoubled its efforts and applied its funding toward the conversion of overhead power lines to the underground replacement of end-of-life direct buried cables and the installation of tree wire, plastic-coated overhead conductors used in heavily wooded areas prone to limbs and branches falling. Although 70% of the total system is now underground, 50% of the three-phase backbone remains overhead, surrounded by massive fir trees. It was not practicable to convert the backbone to underground, so Peninsula Light Company looked to automation using the ADMS to improve reliability. This required replacing aging field devices with advanced recloser controllers, replacing radio with cellular communications for improved uptime/bandwidth, and upgrading the metering system for real-time outage information. In addition, remote terminal units (RTUs) were replaced with intelligent electronic devices (IEDs) to further integrate status, protection, and control functions. Ultimately, 150 individual RTUs were replaced, all substation reclosers were updated, and 50 field reclosers were added to the system. All of these equip Peninsula Light Company to reconfigure the network in response to a fault and restore service quickly and provide operators with load and demand information.

Once Peninsula Light Company completed the physical and digital upgrades to its grid, the utility took the next step toward reliability improvements, i.e., implementing FLISR on the entire system to segment, isolate, and restore as many areas as possible in the event of an outage.

Peninsula Light Company sought a robust ADMS platform to facilitate the deployment of integrated applications in an evolutionary fashion as utility needs changed. The utility planned to begin upgrades with an integrated status and control system and then to deploy FLISR, before considering additional ADMS applications. Vendor evaluations included reviewing the tools provided to ensure the accuracy of the field data and software, which would increase the efficiency and productivity of the utility's small team. The vendor's willingness to partner with Peninsula Light Company in the development of additional features and capabilities was also studied. The last consideration was resiliency and the vendor's ability to support a redundant server scheme in geographically diverse locations.

The importance of an offline, project-based data validation system to the utility cannot be overemphasized. An ADMS that would enable the utility to validate the accuracy of configuration changes and GIS data imports before being used in production was paramount. The accuracy of data and the network model in the old GIS had become increasingly inaccurate over time, as demonstrated by the utility detecting more than 50,000 errors when connectivity tests were conducted from the substation to end-of-line meters. The utility's goal was to use the offline system to correct the network model and maintain the accuracy of the system as it grew.

Having found an ADMS vendor that met all of these criteria, Peninsula Light Company partnered with an operational technology (OT) consultancy and built out its operational network to include redundant servers in an off-site data center and additional redundancy in the headquarters building, along with go-bag workstations that included a laptop, cellular modem, and satellite phone. Two-factor authentication, a mobile device management system, and limited compartmentalized access provided the resiliency required and guaranteed that critical infrastructure protection best practices were incorporated.

Results

Peninsula Light Company has seen little to no unplanned downtime, even under stress, since commissioning the new OT infrastructure, architecture, and the tri-redundant ADMS. The most recent storm season brought more snow to its territory than has been seen in more than 70 years (see Figure 3). This caused an outage of all transmission lines connected to the Peninsula Light Company service territory and was the first system-wide outage since the system was commissioned. Previously, operators lost communication with field devices and were required to restart or perform emergency maintenance on the legacy SCADA system, all of which interfered with their ability to manage restoration activities efficiently. With the new ADMS in place, operators were able to focus solely on the outage and power restoration.

Equally as important, the utility has realized cost and operational savings through the enactment of the ADMS. Peninsula Light Company's financial savings are primarily a result of the elimination of unnecessary work and the loss of productivity caused by system crashes. In the past, the utility would often factor time into switching orders/plans to dispatch staff to SCADA system-equipped sites. As each site is brought into the ADMS with a cellular modem, that need has now disappeared.

figure 3. Heavy snow and large trees take down power lines in Peninsula Light Company's territory. (Source: Peninsula Light Company; used with permission.)

In addition, the utility estimates that approximately 80% of a full-time employee's time was spent managing the previous SCADA system through crashes, restarts, and trouble ticket management. The robustness of the ADMS has freed up that time for system planning, an advanced metering infrastructure (AMI) deployment, and mobile workforce management tools, all of which added to productivity and efficiency improvements. The IED and control panel templates offered by the ADMS vendor have saved the utility countless hours when deploying new reclosers, as compared to the previous SCADA system and field-based RTUs, which required the manual configuration of every point.

Lessons Learned

A key factor in the success of an ADMS project is understanding that the applications must be considered part of the complete system. Users should consider and integrate all aspects of the ADMS, from the electrical system to the model to the digital system.

When evaluating ADMS options, Peninsula Light Company recommends evaluating not only the applications that promise the greatest returns in reliability or resiliency but also the applications and tools that will allow operators to be more productive using fewer resources. In Peninsula Light Company's case, this included tools that increased the ease and accuracy of GIS data imports and streamlined equipment deployment. For example, IED and control panel templates enabled the utility to set up a single device once and propagate it across all identical sites in the field for speed and consistency. Where it previously took several hours to set up a new relay within a data concentrator, templates now enable the utility to set up an entire substation in under an hour. Tools such as these free up SCADA administrators, operators, and field crews to perform more critical tasks and eliminate the risk of knowledge loss about unique sites as operators retire or leave the utility.

Finally, to overcome resistance to change, the utility stresses the importance of leadership buy-in as well as letting users see, early on, how the system will help them in their role. For Peninsula Light Company, the big shift came with the generation of a switch order from a single FLISR operation during a test. FLISR showed that an area was not restored due to a smaller wire type, a bottleneck that went unnoticed during manual activities.

Achieving the Utility of the Future

From DERs to smart devices to distribution automation, the pace of innovation in the electric power distribution industry is accelerating. Large and small utilities are subject to the same challenges and expectations—improving reliability, increasing customer satisfaction, effectively leveraging DERs in the grid, and trying to achieve all of this with a dwindling skilled workforce.

Smaller cooperatives and municipally run utilities are meeting these challenges through a variety of avenues, including

- ✔ deploying innovative but proven technology
- ✔ establishing supportive vendor relationships
- ✔ developing partnerships with vendors and national labs to evaluate and test a variety of grid modernization solutions
- ✔ ensuring that new technology investments and upgrades are highly interoperable.

Ultimately, these utilities are well positioned for success now and well into the future.

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