Business & Technology Surveillance

A Measured Approach to Distribution Automation for an Evolving Future

By Jim Weikert, Vice President of Utility Automation & Communications,
Power System Engineering

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NRECA
America's Electric Cooperatives

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SUBJECT MATTER EXPERT ON THIS TOPIC

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This article is a product of the Analytics, Resiliency and Reliability Workgroup.

ARTICLE SNAPSHOT

WHAT HAS CHANGED?

Electrification and distributed energy resources (DER) will continue to increase, and as they do, member expectations for resilience will also increase.

WHAT IS THE IMPACT ON ELECTRIC COOPERATIVES?

Increased expectations for resilience will impact cooperatives' approaches to managing a grid with more dynamic power flows.

WHAT SHOULD CO-OPS KNOW/DO ABOUT IT?

Cooperatives will need to incorporate distribution automation into their systems and processes over time in order to align their investment with changes in member expectations. It will be beneficial to take a measured approach by testing new technologies along the way, strategically adding communications, and evolving operational procedures as learning and trust build, while maintaining the core principle of safety.

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Executive Summary

Distribution automation (DA) has been a topic of interest for years. Many utilities have been increasing the intelligence of equipment on their distribution feeders. Intelligent capacitor bank controllers have become common for managing volt-ampere reactive (VAR) changes based on load and seasonality. Intelligent reclosers are used by almost every utility within their substations, and many cooperatives are upgrading hydraulic reclosers to intelligent devices on feeders.

Several things have brought distributed automation to the forefront for many cooperatives. Recent grant funding is reviving interest in automation projects that had to take a back seat to more pressing system investments. Additionally, anticipated increases in member renewable generation and storage have raised questions about what system automation will be needed to manage a more dynamic system.

This article is the second in a set, the first of which discussed **Advanced Distribution Management Systems (ADMS)**, a topic that goes hand in hand with distribution automation. Because ADMS and DA are complementary, this article is focused on the field equipment that enables the functionality provided by ADMS software systems.

Various manufacturers and technologies will be mentioned in this article. This article is not intended to be exhaustive in coverage of available technologies, and NRECA encourages cooperatives to consider all available technologies to determine which best meets their own specific needs and circumstances.

This article discusses DA by covering:

- Substantiating the Pursuit of DA
- Foundational DA Tools and New Advancements
- Impact of Microgrids and DER
- Unlocking DA Potential Through Secure Communications
- How to Incorporate DA into Operational Procedures

The culmination of this discussion is an understanding that electrification and DER will continue to increase, and as they do, they will have a significant impact on member expectations for resilience and on cooperatives' approach to managing a grid with more dynamic power flows. While electrification and DER will increase, we recognize that there is a fair amount of uncertainty in the timeline.

With that understanding, the article makes four recommendations for approaching DA:

1. **Begin Sustainable Progress**
2. **Incorporate Measured Innovation**
3. **Strategically Add Communication**
4. **Operational Evolution**

Incorporating distribution automation into your system and processes is a very achievable goal, if done in a measured manner.

Why DA?

DA technologies provide a lot of visibility into what is occurring on your distribution system. They also enable remote control of equipment from your office. While visibility and ease-of-control are immediately attractive benefits, it is important to concretely understand all the benefits to your utility before making an investment. Every investment is a trade-off with other potential investments, and as good stewards for your members, it is important to choose the investments with the greatest benefit.

MORE EFFICIENT RESTORATION

Cooperatives have always been dedicated to restoring power to their members as quickly and efficiently as possible. Crews respond promptly to outages day and night. During major storm outages, cooperatives locally and across the country show great support for each other in offering mutual aid.

DA offers the ability to improve responsiveness for restoration. As cooperatives consider leveraging DA, they search for guidance on how to quantify its benefits.

Outage cost calculators, such as the Interruption Cost Estimator (ICE) by the Department of Energy[1], help cooperatives estimate the cost of outages to your members. The tool estimates costs per outage, ranging from less than $10 per hour for residential members to several hundred per hour for commercial members, and more than $1,000 per hour for industrial customers. While outages costs vary widely depending on the consumer, cost estimates in ICE are based on a broad set of surveys of historical reported outage costs and reflect realistic national averages.[2]

However, neither the costs nor the savings calculated using these tools directly correlate to the cooperative. For example, the ICE calculator estimated that a modest improvement of 10 minutes in System Average Interruption Duration Index (SAIDI) and 0.1 in System Average Interruption Frequency Index (SAIFI) would equate to a benefit of $3.7 million to members for a cooperative of 25,000 residential and 1,000 commercial and industrial members over 25 years. While this may be true, these benefits are not reflected in the revenues and costs in a cooperative's financial reports.

There are benefits that do flow to the utility's financials from DA. For example, crews do not have to spend as much time searching lines for faults if DA equipment can identify the spans on which the fault has likely occurred. They may not have to drive to locations to isolate a fault and close a tie point if DA equipment can automate this.

Some of these benefits are tangible or hard savings, such as reduced wear and tear on vehicles or overtime during storm outages. Some of the savings are soft savings, such as less time for crews spent on outage restoration or less time spent by member service representatives addressing outage questions from members, allowing more time to be spent on other activities. However, these soft savings do not generally directly impact payroll costs. Estimates that Power System Engineering has done previously show savings of $100 to $1,000 per outage from DA efficiency improvements, with the majority of these savings being soft savings.

Depending on the perspective, member economic benefits could be used to substantiate investment in DA, with improvement costs passed along to members in rate increases with the understanding that members will realize benefits as well. However, many members start with an underlying assumption of reliable service and often do not recognize the improved reliability as a benefit worth extra payment. In addition, some of the economic benefits to members are soft savings as well, especially for residential members who make up the majority of a cooperative's membership.

For many cooperatives, the question remains: *what should cooperatives do if DA resilience deployments do not have a positive return on investment for the cooperative?*

While the economic impact of an outage is more tangible for businesses and especially industrial members, changes in the electric industry are increasing the reliance of residential members on electricity. Homeowners are being encouraged to transition to heat pumps. Rural homes are increasingly provided with high-speed internet, allowing more and more rural residential members to work from home, increasing the importance of reliable power to that of a small business.

The importance of reliability is further driven by increased beneficial electrification. Projections from the U.S. Energy Information Administration, Annual Energy Outlook 2023 (AEO2023) show projections of electric vehicles increasing to 20% nominally (see **Figure 1**). Other models predict sales of electric passenger vehicles increasing to 60% of new car sales by 2050.[3] As these and larger scale transportation such as school busses are battery powered, quick restoration of outages will be necessary for people to get to school and work.

Although electrification will lead to additional energy sales, the economic benefit to utilities

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1 **https://icecalculator.com/home**

2 Sullivan et al. 2015. Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, **https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf**

3 Reuters. 2022. The long road to electric cars. **https://www.reuters.com/graphics/AUTOS-ELECTRIC/USA/mopanyqxwva/**

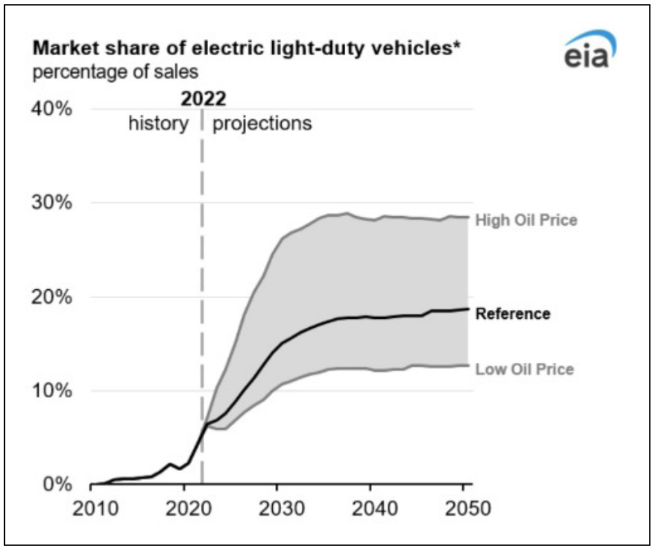

FIGURE 1: Projections of Electric Vehicle Sales

of electrification is clouded with potentially increased demand charges. Residential and public electric vehicle (EV) charging can significantly impact peak demand if not managed well.

In the end, rapid restoration and higher resilience may not have a clear positive return on investment (ROI). The benefits of efficiency savings are sometimes soft. The economic benefit of supporting increased demand, while positive, is dependent on many factors that are in flux. Regardless, expectations are increasing for supporting these industry changes. Cooperative members will come to expect utilities to leverage technology to improve reliability – and their frustration will be vocalized as they come to depend on electricity more and more for internet and transportation.

It is important for cooperatives to make cost-effective, incremental investments in system improvements that will collectively result in substantive improvements. Electrification changes in the industry will evolve over time. Spreading system enhancements over a period of time allows a co-op to progressively improve responsiveness, while also managing costs. It also avoids the need for very large investments in the future in order to catch up with needed enhancements and the increased reliability expectations that are likely to come.

MANAGING VOLTAGE IN A DYNAMIC FUTURE

Co-ops have traditionally managed challenging voltage scenarios on a given feeder that is often five or more miles long. To do so cost-effectively, co-ops have installed capacitor banks and regulators at fixed locations to remediate known issues.

However, the decision of where to place voltage- and VAR-correcting equipment has traditionally been based on predictable and repeatable load profiles. Residential load has traditionally been characterized by morning and evening peaks, and larger commercial and industrial loads are generally well understood by the cooperatives that serve them.

Many aspects of loads will continue to be able to be characterized, even with transition to electrification and electric vehicles (EVs). While the curves may be different than they are today, predictable patterns will develop.

However, increases in DER will add variability that will be much harder to characterize. Figure 2 from the U.S. Energy Information Administration Annual Energy Outlook 2023 (AEO2023) projects solar generation growing significantly in the next 15 to 30 years.

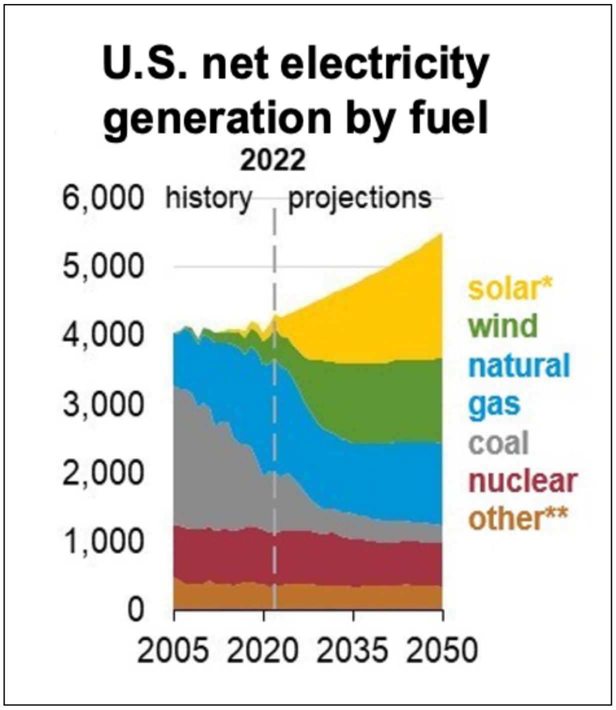

FIGURE 2: Projections of Types of Generation Growth

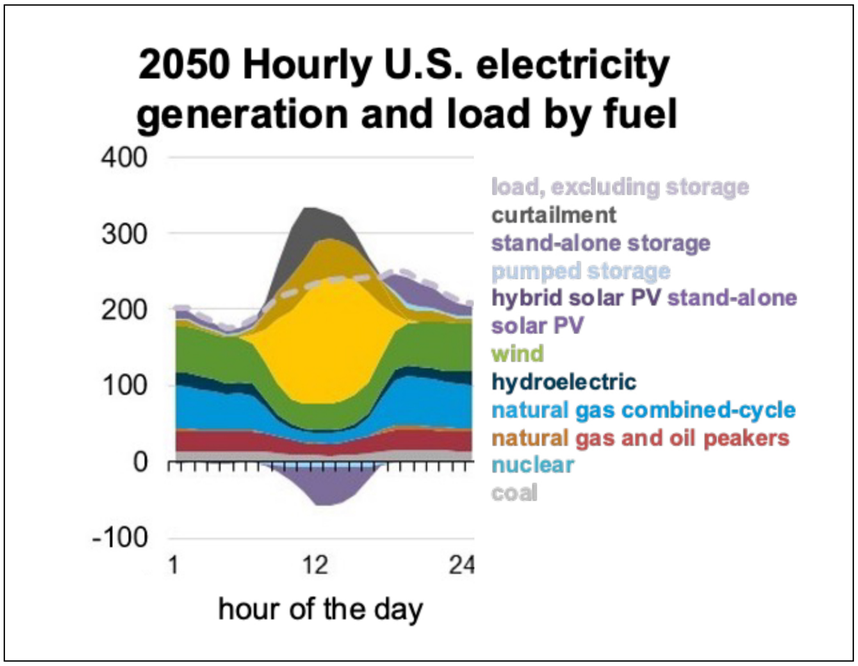

FIGURE 3: Projection of Generation and Storage Throughout a Day

Solar renewable energy can fluctuate throughout the day and change the voltage profile of a feeder. Figure 3, also from AEO2023, projects a dynamic mix of generation and storage throughout the day.

As batteries become more commonplace, they will likely be aggregated as a resource to be used by regional transmission organizations (RTOs) to manage generation and transmission. Use of distribution-connected batteries as a dispatchable resource adds additional variability, as the resource usage can be dependent on many factors outside of the distribution cooperative's visibility.

Traditionally, Volt/VAR automation has a positive ROI. Adding localized capacitor bank controls that adjust to VAR levels throughout the day and reduce line losses also frequently has a positive ROI. Adding automation to perform conservation voltage reduction is often beneficial for utilities with demand charges in the range of $10 to $20 per kW month, if they are able to reduce demand by 1 to 2%.

What may be new is the necessity of having automation for Volt/VAR control, in order to manage an increasingly dynamic voltage profile.

Tools in Your DA Toolbox

Given the increasing importance of automation, it is valuable to understand what tools are available when looking to add automation on your feeders. This will allow you to select the combination of tools that will most effectively help you achieve your goals.

This section starts by discussing foundational tools along with improvements that have been recently introduced to those tools. It talks next about new tools being introduced to extend automation to the grid edge. It expands on this by discussing how microgrids are starting to benefit the distribution system, and ends by talking about the impact of DER and ways in which to manage DA systems beyond using an ADMS.

The following section complements this discussion by highlighting various communication technologies and the means to implement DA securely.

FOUNDATIONAL TOOLS

Many cooperatives have been deploying feeder equipment with intelligent controls for years. Intelligent reclosers are common for protecting a distribution system. Intelligent regulators and capacitor banks are common for managing voltage profiles. Many manufacturers offer intelligent controls including SEL, Eaton, Beckwith, Siemens, Schneider, ABB, and many others. These are complemented with manufacturers of electrical equipment including G&W Electric, Hubble, and others. Each utility has its own priorities for determining preferred vendors, including reliability of the product, quality of support, familiarity with the user interface, cost, and other factors.

While much of the focus in the industry centers on the automation systems that coordinate much of this equipment, the largest investment a cooperative makes to implement DA is in the field equipment and controls, as well as distribution system upgrades to support reconfiguration. While many aspects of technology are changing rapidly, much of the foundational investments in equipment that can be automated and accompanying upgrades to the system are very stable.

When considering enabling automated restoration or switching, equipment including pad-mount switchgear and overhead switches and solid-dielectric reclosers are mature products that have a proven history of reliable operation. Investment in converting an oil circuit recloser (OCR) to a remotely operable recloser can be $30,000 to $60,000 per location. Pad-mount switchgear that can support multiple protected and switched ways can be an investment of $100,000 per site. Similarly, intelligently controlled regulators and capacitor banks are mature and proven products.

Fortunately, investments in this equipment will last 30 years or more. These investments, and investments in the corresponding distribution system, can be made based on long-range planning procedures to enable enhancements to the system over time.

When deploying reclosers, regulators, cap banks and other equipment to support DA, the equipment itself is complemented with a controller. Recent years have shown many advances in these controllers that have resulted in a maturity of technology that did not exist 10 years ago. While many aspects of electronic technology are continuing to advance, controls manufacturers have addressed many shortcomings that existed with some early editions of the equipment and closed gaps in functionality to a point that the industry now offers a broad set of solutions that can be leveraged for a long time. Previous generations of electronic controls might have had a lifecycle of 5 to 10 years before significant advancements in newer generations incentivized early adopters to upgrade their equipment. Current generations of these controls offer the maturity that the investment can reliably be expected to last for 15 to 20 years.

Figure 4 illustrates variations in maturity of various components of DA technology. Electric equipment (regulators, reclosers, cap banks) is very mature. Controllers for those pieces of equipment are quickly reaching a similar level of maturity. Many other components are still emerging. New grid edge DA devices are being introduced to the market each year; and microgrids, while reliable, are still an innovative solution in the industry.

While new controllers have become mature, they frequently still support legacy automation technologies. In particular, many support both serial and Ethernet communications. Power System Engineering recommends selecting models with Ethernet. It allows for flexibility of multiple types of communications with a device in the field. It allows SCADA monitoring and control, recovery of sequence of event data, and investigation of settings over a single communication channel. Support for all of these features avoids the need to drive to the field to retrieve valuable information.

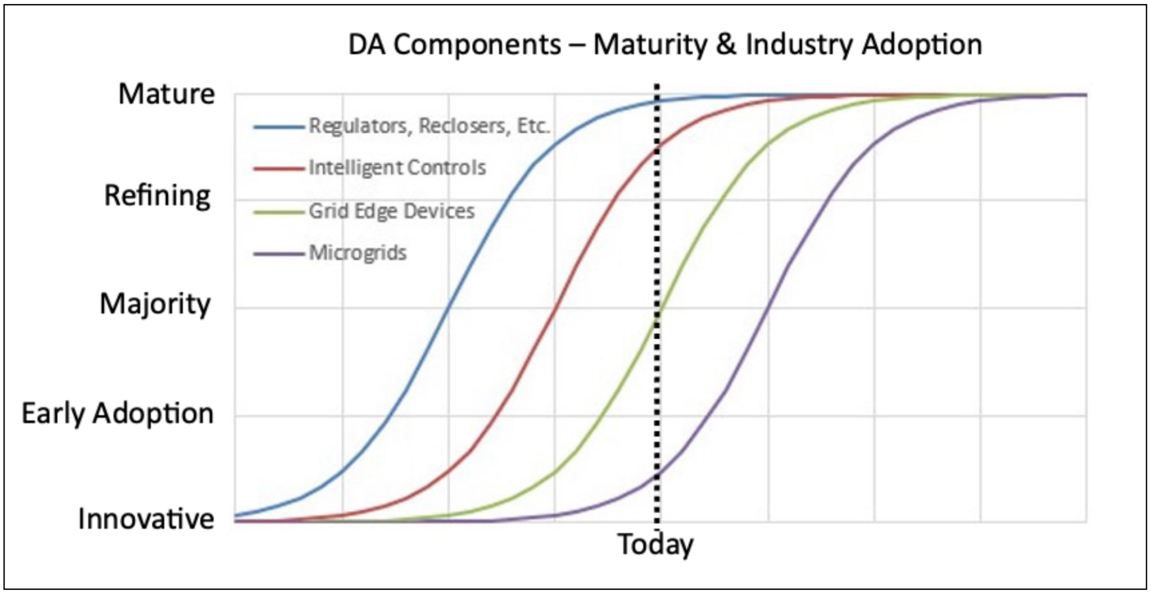

FIGURE 4: Variations in Maturity of Various Components of DA Technology

< PREVIOUS VIEW >

Some had used serial communications previously, in an attempt to minimize the security policies they implemented. They avoided many good cybersecurity policies, including authentication and traffic monitoring. Policies such as these provide a foundation of best practices, and when they are implemented, they enable the full power of DA investments to be leveraged.

ADVANCEMENTS TO FOUNDATIONAL TOOLS

Beyond the many advancements that have now matured, the industry is continuing to develop new products to support DA.

While not new, some relay and recloser control manufacturers have enabled interactions between devices which leverage high-speed communications to coordinate rapid fault isolation and restoration. The vendors that offer this add additional intelligence into their devices to make decisions based on data shared with neighboring controls. While often leveraging standards-based communications such as DNP[4] or IEC-61850[5], the intelligence in each of the devices adds functionality unique to that vendor and which frequently cannot be achieved if also incorporating other vendors' equipment.

For many years, S&C has offered enhanced products that include their IntelliTeam® and IntelliRupter® PulseCloser® products. The IntelliTeam recloser controls communicate using DNP amongst themselves, as well as with a SCADA system. Through inter-device communication, they are able to share information about faults and loss of voltage that enable the devices to isolate issues and close alternate sources when appropriate to automatically isolate and restore portions of outages. The PulseCloser® products incorporate S&C's PulseFinding™ technology. These devices enable increased segmentation along a line, while mitigating overlapping coordination curve issues. The technology allows the devices to reclose for an extremely short period of time to test for a downline fault. This rapid test allows for successive tests for a fault by a series of devices along a line, while also reducing sag on upstream devices. It enables location and isolation of faults along a section of line with multiple devices independent of communications.

Siemens is another example of a manufacturer offering enhanced interactions as with their 7SC80 distribution network protection device. Utilizing high-speed IEC 61850 communications between controllers on a line segment, the devices are able to share information amongst each other. In a process Siemens refers to as Siemens Distribution Feeder Automation System (SDFA), the devices compare dynamic current amongst each other to detect the location of the fault and isolate and back feed in less than a second.

SEL has for years supported communication-assisted protection schemes. Their mirrored bits communication technology is used widely for coordination between relays to trip them rapidly based on information shared. In addition, SEL supports configuration of multiple devices in close proximity to sequentially test for faults in reclosing, and isolate a fault independent of communications.

Regardless of the level of coordination between devices, even traditional controllers provide fault currents which can be used by an Outage Management System (OMS), ADMS or an Engineering Model to narrow the location of the fault, frequently within several spans.

ADVANCEMENTS IN GRID-EDGE DEVICES

Beyond the enhancements to core feeder equipment, the industry continues to develop technologies that supplement the core. One of the more recent introductions into protection has been the addition of low-cost reclosers that can act as fuse replacers.

These small form factor reclosers often have self-contained intelligence and can sometimes be mounted in a fuse cut-out. One of the benefits of such an offering is that it avoids some of the trade-offs that have been made traditionally between fuse saving and fuse sacrificing.

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4 Distributed Network Protocol

5 IEC 61850 is an international standard defining communication protocols for intelligent electronic devices at electrical substations. It is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 reference architecture for electric power systems.

Fuse sacrificing schemes are designed such that the fuse will blow before a main line recloser trips power to the whole line. However, this necessitates a truck roll to replace the fuse. Fuse saving schemes avoid the fuse having to be replaced, but expose customers on the whole feeder to outage blinks.

The self-contained intelligence in these simplistic reclosers minimizes cost and expands functionality. Additionally, vendors allow communications to be added optionally, enabling visibility that cooperatives did not previously have.

In this classification of device, S&C Electric offers the TripSaver® II Cutout-Mounted Recloser, ABB offers the Eagle single-phase recloser, and Hubble will soon be introducing a similar device. Each of these devices are self-powered, do not require batteries, have intelligence built in, and offer options for remote communication.

For co-ops looking to enhance visibility into their system, improvements made to enable intelligent protection to single-phase taps can be complemented with intelligent faulted circuit indicators (FCIs). These smart FCIs help detect issues on the many portions of a system which still leverage traditional Oil Circuit Reclosers (OCRs[6]) and fuses for protection.

While Advanced Metering Infrastructure (AMI) systems provide valuable information on outages, smart FCIs fill gaps that are otherwise harder to access using AMI data alone. Many provide valuable fault current data, which can be used to determine the location (span) where the fault occurred or where momentary faults may be occurring.

In addition, smart FCIs provide more granular real-time data on system loading. While an ADMS system can estimate loading, it uses load allocation based on average values defined by the utility across all the meters. These averages do not account for real time fluctuations. As EVs, residential solar, and storage increase in popularity, loading of individual taps could vary significantly over a feeder from numbers calculated from averages. While AMI meters can be used to detect voltage issues, smart FCIs can provide that information much more quickly and provide information on trends that voltage alarms do not provide.

Many vendors provide smart FCIs, including the Eaton GridAdvisor Series II Smart Sensor, Sentient Overhead and Underground Line Sensors, SEL's Fault and Load Transmitter and Receiver System, and Power Delivery Products' Smart Navigator.

Most Smart FCIs have many qualities in common, including harvesting power from the power line, though it is important to understand how much current must be present for the FCI to be active. Important additional considerations include:

- **Fault Monitoring and Reset Method:** Some FCIs are intelligent enough to adapt their fault limit based on recent averages, while others require programming.
- **Communication:** Options include cellular, support for particular AMI networks, 900MHz network, or just an Ethernet connection for a separate communication network.
- **Mobility:** If using FCIs to troubleshoot issues, its easiest to use those that do not require a base station for communications and that minimize reconfiguration.
- **Accuracy:** Accuracy of the current sensors varies significantly from +/-25% to +/-1%. It is important to look closely at the device based on your intended application.

Some smart FCIs have capabilities well beyond basic current measurement. Advanced devices support measurements of harmonics for power quality detection. Sentient Energy is offering a new product with the ability to flag anomalous current patterns indicative of potential fault issues, such as insulator arcing or vegetation contact.

Newer advances are spreading to the grid's edge. We recommend that the majority of your investment focus on proven equipment on your backbone. In addition, we suggest allocating a percentage to newer grid edge devices to test out their reliability and benefit to you.

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[6] An OCR is an automatic high voltage switch that shuts off electric power when a short circuit fault occurs out on the power line.

MICROGRIDS AS A RESILIENCE ENHANCER / PEAK SHAVING

While cooperatives have traditionally looked to automate existing protection and voltage equipment on their feeders, some utilities are also looking at a microgrid as a tool to improve their system.

Microgrids, as a broad concept, cover any configuration in which an energy source is connected to a distribution system such that it can operate independently if the primary source of power is unavailable. While many sources of energy can be used, we are increasingly seeing battery storage as that source, sometimes coupled with solar generation. Historically, deployment of these technologies has been driven by large tax incentives. The passage of the Inflation Reduction Act is providing new incentives. We suspect this will mean rapidly increasing DER and microgrid deployment.

When looking to add storage, not infrequently, co-ops are looking to add it at one of their substations or delivery points to remediate issues they might be having with reliability of power delivery. As an example, one small community of 200 in Wisconsin was having repeated power outages with the one main distribution line that fed it. These outages impacted not just residents and businesses, but also public works and utility services.

The local utility installed a 400 kW/3,200 kWh microgrid using Lithium Iron Phosphate batteries. The installation, shown in Figure 5, was designed as a modular solution provided by WEG. The main unit is environmentally-controlled and contains the battery bank, power transformer, bi-directional converter, AC and DC switchboards, and microgrid control.

FIGURE 5: Microgrid Using Lithium Iron Phosphate Batteries

The controller used for the microgrid was the SEL PowerMAX. The PowerMAX is a configurable microgrid controller that is capable of operating on several of SEL's platforms. It is available as a component of some of their protection controls, including the SEL-700GT Generator and Intertie Protection Relays, the SEL-735 metering system, and more. SEL also offers multiple dedicated rugged rackmount computing platforms, including the SEL-3530 RTAC, the SEL-3355 platform, and others on which PowerMAX can run.

PowerMAX Power Management and Control System is designed for uninterrupted energy delivery to a facility or a community. The algorithms refined by SEL are based on over 20 years of experience providing solutions for uninterrupted energy. The platform works closely with SEL relays to provide a reliable protection system for both utility generation as well as nuances from generators and inverters used for renewable and battery generation.

It can work as a standalone as well as in response to real-time pricing signals to balance load and generation, seamlessly islanding when the grid is unavailable and eventually resynchronizing once the main source is restored. It also supports schemes that "self-heal," rerouting power around one or more faulted areas to maintain service elsewhere.

Beyond this example, many vendors offer microgrid controllers. Eaton offers the Power Xpert Microgrid Controller. It maintains overall system stability regulating power flow and monitoring protection schemes in real-time, while dynamically managing generating assets and loads to meet user-defined goals. Users can set control strategies to enhance resiliency, maximize renewables, reduce utility charges, or execute combinations of prioritized strategies. Its human-machine interface (HMI) provides system configuration, device monitoring, and application control functionality. Its optional integrated historian continuously monitors system performance and collects detailed operational history. The Power Xpert Microgrid Controller is built on the SMP family of controllers coupled with

Eaton's Visual transmission and distribution (T&D) HMI products.

Schneider Electric offers microgrid solutions based on their Energy Control Center (ECC) product and their EcoStruxure Microgrid Operation (EMO). The ECC platform is a pre-wired assembly of panels with distribution equipment and controls to manage a local set of DERs. The EMO coordinates multiple assets, one of which will act as the frequency source, to allow other resources, including solar, to function through an outage and balance load and generation.

Approaches to managing microgrids and the ability of microgrid controllers to adjust protection, island, and synchronize and manage load vary significantly from platform to platform.

DISTRIBUTION AUTOMATION COORDINATED OUTSIDE ADMS

While DA equipment commonly complements a centralized SCADA or ADMS system, many cooperatives do not have the resources to deploy SCADA or a full ADMS.

In those instances, a consideration that can be made is to deploy systems of smaller scale which focus on a more targeted automation goal. There are Fault Location, Isolation & Service Restoration (FLISR) solutions in the industry that can be used for automating restoration. And there are Integrated Volt/VAR Control (IVVC) solutions that can be deployed. Each of these can be deployed as a fully stand-alone system or as a complement to a separate SCADA system.

Several FLISR options exist. For many years, Eaton has offered its Yukon Feeder Automation (YFA) software. This software runs on a Windows Server or PC. It communicates with devices in the field to coordinate automating fault isolation and reconfiguration or loss of source voltage reconfiguration. The primary user interface is a one-line diagram that illustrates substations and primary feeders and the protection equipment being controlled. In addition to many other capabilities, it interacts with field equipment to understand the full extent of system faults and follows extensive safety protocols to safely isolate faults and restore power to isolated segments.

Another FLISR solution is offered by SEL. Expanding upon the strength of their popular Real-Time Automation Controller (RTAC) platform, SEL is now offering their Blueframe Application Platform, an embedded Linux or Windows operating system which runs on a host of their computing platforms including the SEL-3350, 3355, and 3360. Blueframe is meant to have applications such as SEL's FLISR application loaded and run on it.

SEL's FLISR solution is a self-contained application for FLISR including configuration tools, user interface, communications protocols and FLISR logic, in addition to many other features. It provides users a one-line interface of any portion of their system, accessible through a web browser. Like other stand-alone FLISR solutions, it allows simplified configuration of the network configuration to provide the framework for managing DA equipment for automated restoration.

Other vendors offer similar solutions which can be considered for self-contained FLISR implementation.

Similarly, vendors offer self-contained IVVC solutions. Eaton's Yukon Volt/VAR management software is a self-contained application for managing regulators, cap banks, on-load tap changers (LTCs), and other equipment to achieve various voltage and power factor control targets. In addition, it supports implementation of Conservation Voltage Reduction (CVR) for temporary demand reduction at peak demand.

Unlocking DA Potential Through Secure Communications

Most intelligent devices work well without external communications. Reclosers and fuse replacers perform their system protection based on the knowledge that they have. Similarly, regulators and cap banks can be programmed to make decisions based on local voltage and VAR flow.

That said, the benefit of a Smart Grid comes from the ability for operators to leverage a broad set of intelligent devices collaboratively for a common benefit. Utilities have the greatest benefit when they are able to collect information from multiple devices into a common picture. They benefit the most when they can coordinate multiple devices across a distribution system. And ultimately, managing the grid will be a coordinated effort between transmission and distribution entities to see a whole picture and manage resources for common benefit.

Given this, communications networks are essential to facilitate broad coordination of DA.

While advances are occurring in DA equipment itself, technologies for communications networks change much more rapidly. New communications technologies are released each year. While new technology can be interesting, it is important to understand that technologies that have been around for many years can be just as beneficial as those recently introduced. A challenge of changing technology is that the options from which you can select change frequently. Additionally, the lifecycle of communications equipment is typically shorter, with a replacement period of 5 to 10 years, as compared to 20 or 30 years for a recloser or regulator and 15 to 20 years for the intelligent controls.

Given the continued evolution of communication technology, we believe there is value in developing parallel but separate paths for deploying DA equipment (talked about in the previous section) and the communications equipment discussed here. The following section elaborates on this point.

TECHNOLOGY CONSIDERATIONS

The best technology selection should be based on a set of factors including bandwidth, coverage, installation cost, operational and maintenance cost, and security. Figure 6 is a simplified representation that compares the bandwidth of several technologies to the bandwidth needs for various uses.

While a full article would be necessary to cover all of the considerations carefully, the summary below provides a good introduction to many technologies that can be used for DA.

- **Cellular**
  Utilities have increased use of and reliance on cellular for DA communications significantly over the past 5 to 10 years. As speeds have increased, latencies which had been noticeable in 2G and 3G are now fine for most applications. In addition, a large percentage of rural territories now have reasonably good 4G/LTE (long term evolution) cellular coverage. To complement this, providers have gotten better at providing affordable data plans for the small data needs of DA devices. Remaining concerns to consider are typically reliability during major storms and the frequency at which the equipment may have to be changed to adapt to new standards. Regarding reliability, as with any leased system, utilities cannot control repairs to the network.

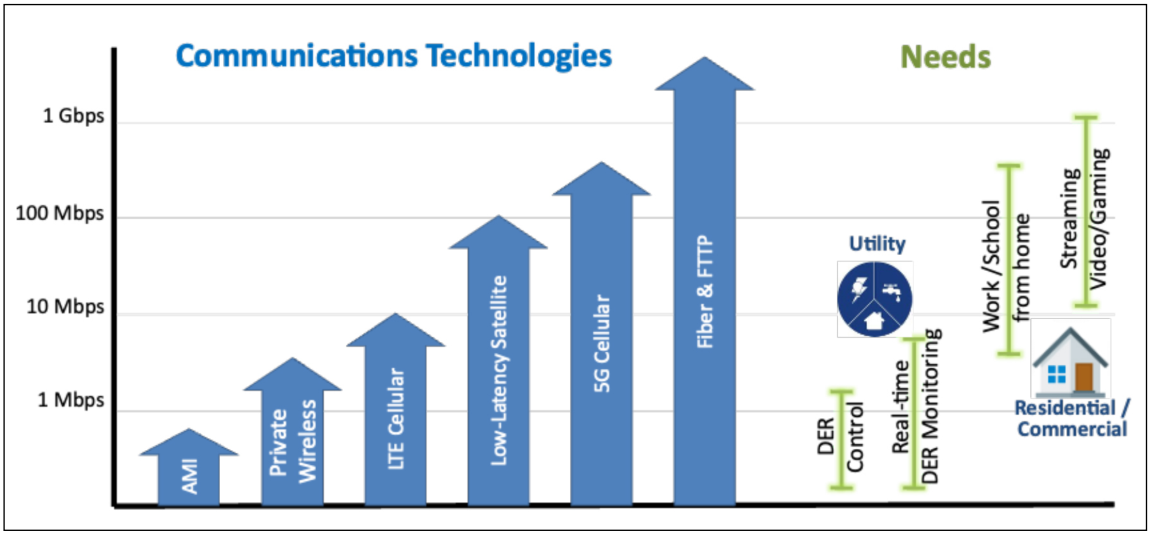

FIGURE 6: Comparison of Technologies' Bandwidth to the Needs of Users

- **Fiber**
  With increasingly wide deployment of broadband, availability of private and leased fiber for DA has increased significantly. Fiber provides much more speed than is needed, and the cost to run fiber exclusively for a DA point is typically prohibitive. However, if fiber is located close to a DA location, fiber makes a lot of sense. But, it is important to understand the network and its limits on redundancy. Most fiber networks are radial and deployed on the same overhead lines as the electric system being managed. Outages caused by trees, ice, cars, and other things impacting the lines can also disable the communication network.

- **Low-Latency Satellite Communication**
  While other wireless networking services are increasingly available in rural areas, some areas still do not have good availability. While satellite has been around for many years, the recent introduction of StarLink satellite has greatly changed the ease of signing up for and deploying satellite communications. The Low-Earth Orbit (LEO) technology that StarLink uses has significantly shorter round-trip delay (latency) at 25-50ms, a latency comparable to cell and terrestrial broadband networks, which makes it much more feasible for DA communications. Its most significant drawback is that the monthly cost is high for feeder equipment. With a cost of their Standard service at $120 / month per link, it is expensive for controlling a single DA location. But, the price could be acceptable for a substation or an AMI collector, and the 10Mbps up / 100Mbps down throughput provides enough bandwidth for these applications.

- **AMI**
  Many utilities use their AMI network as a communications network for DA. Most AMI vendors support auxiliary communications with equipment such as SCADA. The primary considerations in leveraging AMI for DA are bandwidth, resilience, and the type of communication the AMI network will support.

  For resilience, it is important to make sure that the AMI path used for communicating any fault related data travels over AMI equipment has a battery backed power source. Depending on the architecture, repeaters may be needed for the DA location to communicate with AMI gateways. If this is true, the path must be configured to avoid hops through meters and use only battery-backed repeaters to get to the gateway.

  Beyond this, the data that you wish to communicate with a DA device and the bandwidth required to do so are important considerations. Some vendors support a fully transparent IP connection to the DA device, allowing both SCADA and engineering traffic. Others leverage a proprietary exchange to the DA device, which supports SCADA well, but does not allow remote engineering access. As AMI networks support IP traffic, it is also critical to understand the bandwidth capacity for which the network has been designed and its ability to support DA traffic in addition to AMI interval data and other traffic.

- **Private Wireless**
  Many utility-owned wireless technologies have been used for years to support DA. The biggest advantage of a private wireless network is generally that the utility has full control over the design, coverage, capabilities, reliability, and maintenance of the infrastructure, allowing them to adapt it to their needs and make repairs immediately, if necessary, and design in adequate disaster recovery.

  Private wireless technologies communicate over frequencies including 220MHz, 450MHz, 900HMz, 2.4GHz, and 5.8GHz, with the lower frequencies generally having greater coverage. With some of these frequencies, utilities can leverage a licensed spectrum allowing the utility exclusive use of the band.

- **Private LTE**
  While LTE started as a technology for cellular, the technology has become available for private entities including utilities. Given the capabilities of LTE technology for propagation and performance, private LTE can be a good choice as a broad-purposed field communication network. That said, the cost of infrastructure for private LTE can be significant. Therefore, the network

is typically appropriate only if used for multiple purposes including voice, mobile data, and applications, such as DA, AMI, and substation communications.

Many technologies exist for communications. Given the variety and advances that are occurring, looking strategically at the mix of communication technology that makes sense for your cooperative's needs is important.

CYBERSECURITY CONSIDERATIONS FOR NETWORK INFRASTRUCTURE

Cybersecurity is critical for any utility communication network. Network infrastructure equipment is available today to incorporate core cybersecurity principles into to the networks, including:

- **Encryption**
  Protecting data we send from being read by those we do not want to have access to it.

- **Authentication**
  Verifying that the data is from the source(s) we intend to receive it from and that we are not acting on data or commands injected maliciously – and verifying that those we allow to access the channel are ones we want to have access and do not consume bandwidth that is otherwise valuable.

  Network authentication is the process of verifying the identity of users or devices attempting to access a computer network. This authentication is a fundamental security measure that ensures only authorized individuals or systems can gain access to network resources, such as data, applications, and services, while keeping unauthorized users or potential threats at bay.

- **Detect & Respond**
  Automated systems that can monitor for potential threats and create alerts, allowing staff to take action so that issue(s) can be addressed.

Basic building blocks in securing communication are firewalls, network segmentation, access control, and monitoring software. The list below summarizes functions that are implemented in these different components.

- **Firewalls**
  Firewalls are gate keepers that restrict access to a network, limit data at key boundaries, and identify potential issues. They can be configured to restrict the types of traffic they allow and do not (SCADA, e-mail, browser, etc.), and the addresses of the devices they allow to send that traffic. They can also inspect packets for signatures of malicious content. And finally, they communicate alarms and information on traffic patterns, so network engineers and/or cybersecurity staff can be flagged of potential issues. Firewalls can be used in conjunction with other tools, such as a virtual private network (VPN), to achieve greater security. A VPN establishes an encrypted connection between networks and/or devices and increases the security of communications that must be transmitted over public internet.

- **Network Segmentation**
  Dividing a network into segments or zones helps contain and isolate security breaches. Even if an attacker gains access to one segment, they may be unable to move laterally within the network. Micro segmentation even goes beyond traditional network segmentation by breaking the network into very small, isolated segments, often at the level of individual devices or workloads. This approach helps organizations improve their overall security posture and gain more fine-grained control over network traffic.

- **Access Control**
  Access control mechanisms, such as user authentication and authorization or network access control (NAC), restrict access to network resources. This ensures that only authorized individuals, systems, or devices can access specific data or services.

- **Monitoring Software**
  Finally, in some instances, tools for monitoring network issues and traffic which have been used for many years in IT networks are being extended to OT networks. These tools enable network engineers and/or cybersecurity staff to receive alerts and monitor for issues.

In working to secure the network, an important consideration is whether or not the communication channel traverses any segments that are leased from a third-party. Leased networks have been used for many years, going back to dial-up communications used for substations. As leased connections have transitioned from analog dedicated circuits to packet-based digital communication, data within the leased network is increasingly intermingled with data from others. This is true not just for utilities, but all of the data transferred for corporate communications, banking, and more.

When using networks that can intermingle your data with others', the industry has developed reliable tools to create virtual "tunnels" using VPNs. These tunnels are designed to authenticate that the connection is being established by approved entities and to encrypt the data to prevent others from extracting information from it. VPNs are used every day to create these tunnels and should be incorporated into any DA communication channel, especially if the path traverses a third-party network.

CYBERSECURITY CONSIDERATIONS FOR DA EQUIPMENT

In addition to securing the network, it is important to incorporate security considerations for DA devices. Many utilities are accustomed to managing password access and performing security updates on software systems. These considerations should be extended to intelligent DA devices as well, wherever possible.

Inaccessibility of electronic controls on dedicated networks has historically been used in many industries to secure devices where changing passwords is impractical or infeasible. When devices are located in substations, operators can tightly control the devices and networks that can access them. However, implementing a strong possible password management policy can add additional security and help prevent an unauthorized individual from bypassing other controls. With DA devices located outside of substation fences, the importance of restricting access is considerably increased.

Whenever possible, implementing policies for password complexity and storage, using passwords that are different from manufacturer defaults, and storing passwords securely can significantly increase the security of connected devices.

Beyond this, some are offering software tools to help manage the increasing number of devices in the field, their passwords, software version, and configuration. For example, Eaton offers its IED Manager Suite (IMS) software to manage substation and DA devices. Siemens offers its CROSSBOW software for end devices and network components. SEL offers its QuickSet Device Manager and Security Gateway products.

Many of these systems integrate with Active Directory to allow rapid changes with access privileges should personnel changes happen.

This process is consistent with systems that perform configuration and patch management for compliance with SCADA and ADMS systems. As with these, having an accurate repository of your current configuration and software version positions you well for addressing security issues that need to be addressed.

For further information on cybersecurity for electric cooperatives and related resources NRECA offers members, please visit **cooperative.com**.

Bringing DA into Operations

Many valuable questions arise as cooperatives consider how best to adapt their operational procedures to incorporate DA.

A solid foundation for any adaptation is the understanding that the processes you have developed and used for many years have strong foundations, which will remain.

- Safety of utility staff and the public is embraced as a core value and is given prime consideration in the development of any procedures.
- Communication between all personnel, including line crews, dispatchers, SCADA operators, and supervisors must follow established three-part communication

practices for sending, repeating, and confirming messages.

- Clearance procedures, tagging, visual indications and grounding procedures remain as essential components of any operational procedure.

STEPS TO TRANSITIONING TO DA

As in all endeavors, trust is built over time. As equipment is deployed with increased automation capabilities, we recommend utilities phase in automation capabilities over time to allow the team to become familiar with new processes and to build trust that the procedures account appropriately for all contingencies. The list below provides several phases for incorporating automation:

- **Visibility**
  Incorporate data from remote intelligent equipment into SCADA for monitoring, allowing operators to see that the device is reporting reliably over time and that the data is accurate.
- **Training**
  Provide training for field crews on all SCADA controlled equipment to ensure an understanding and comfort with how this equipment may perform, how to interrogate the device to understand the current state and how to obtain local control and the ability to isolate the device when necessary.
- **Field-Requested Operator Control**
  When first performing control, it can be beneficial to start by allowing crews to initiate any requests for control. This can be done to save time from having to go to a remote location to perform a necessary step. This may be as simple as a request for "Hot Line Tag" or non-reclosing initially, then moving toward actual trip and close operations.
- **Operator Initiated Control**
  As the team builds trust, they can move to updating procedures that allow operators to perform steps, such as isolation and partial back-feed of a non-faulted area, when appropriate data is available while the crews are traveling to a faulted segment of line.
- **Operator Verified Automation**
  Once the team is comfortable that operators can perform limited control based on available information, the team can move to having the operator verify decisions which software is recommending. Here software can recommend steps for isolation and partial back-feeding, and operators can verify the steps are appropriate.
- **Automated Control**
  Finally, once the equipment, processes and systems are trusted, a utility can move to enabling software to make automated switching decisions for improved reliability and restoration time. It should be understood that all traditional safety practices, including visual indications, grounding procedures, clearance tags and local control, are still a required part of the process to ensure safe and efficient operations.

Independent of the phase of incorpora ting automation, there are basic components of operational procedures that should be accounted for. This list is not meant to be comprehensive, but provides a starting point for consideration.

- **Switching Authority**
  Ownership of the switching process should be clearly identified in the procedures. The role to which this responsibility is given must be a trained and knowledgeable person with appropriate experience. It may be the control center operator, the line crew supervisor, district manager or other appropriate person. Responsibility may differ depending on normal shift hours or after hours work or by the type of switching required. This could be routine switching or unique switching for trouble situations.
- **Training for SCADA Operators**
  Consideration of experience of SCADA operators should be thought through carefully and clearly identified, to understand the knowledge implicit in the decisions they are making. A unique balance of system knowledge, field knowledge, and technical skills is desirable. Training for deficiencies in any of these areas is recommended.

- **Documented Switching Orders**
  Regardless of whether they are planned or unplanned, writing out the procedure, double checking it, and documenting what is done is critical to safety. It can be done on a paper form or through a switch order management module in the SCADA software. But, giving order to the process is necessary.
- **Training**
  Just as training is essential for linemen, SCADA operators should receive regular training. Procedural training should be done regularly, so that the process is well understood, especially during storm events. Situational training should be done to review events that occurred and to work through potential restoration, and that training should incorporate how to use the software to perform the necessary checks, validations, and processing of alarms.
- **Clearance**
  Processes need to clearly identify how each party applies and has visibility over tags and clearances. This includes electronic tagging that can be done with software and physical tags on field devices.

STAFFING OPERATIONS NOW & IN THE FUTURE

Beyond components of the process, many distribution cooperatives are considering how they manage a more dynamic distribution system with limited staff. While technology offers many potential efficiency improvements, there are often expectations that the co-op is able to access information and activate controls from a central location in their office. Co-ops commonly have a dispatcher, at least during normal business hours. But, they often do not have staffing after hours, and the background of dispatchers is not necessarily appropriate for being a SCADA operator issuing controls.

To fill this gap, many distribution cooperatives are partnering with their generation and transmission (G&T) to fill some of their staffing gaps. G&T transmission control center operators certainly have the backgrounds and experience to be able to perform switching functions in coordination with coop line crews. And co-ops are exploring several different approaches to addressing the limited bandwidth that G&T operators have. One approach is to leverage the G&T only in the evenings to assist with switching, understanding that the G&T operators will not be burdened with switching for regular maintenance during the day. The evening is also when distribution co-ops lack resources in the office. Another approach is to charge an incremental fee for each operation that the G&T performs, such that they could support additional staffing if the switching requests became significant across their members.

An important consideration is that, over time, the distribution system will become much more dynamic. Power flow from distribution connected generation and storage will increase, and storage assets will likely be dispatched at some point to support the needs of the transmission system. This will increasingly transition management of the distribution system to that of a Distribution System Operator (DSO), a complement to the Transmission System Operators (TSO) that exist today. A G&T's experience as a TSO is likely a resource which distribution co-ops will benefit from leveraging down the road.

Where Should I Go from Here?

Implementing DA across your system reflects a potentially large investment, but a necessary one that prepares your cooperative to meet resiliency demands that will likely increase as electrification increases and a more dynamic power flow emerges with future increased DER deployment. And while economic benefits will result from these investments, the economic return is likely going to be less than the overall investment.

Planning for the future is central to what every cooperative does today. The difference is that planning historically has been based on much higher certainty. Substations are added and lines are upgraded when areas of farmland are likely going to be turned into new residential and industrial development in the coming 5 to 10 years. Equipment is replaced when trends are seen that certain types of devices are showing faults.

FIGURE 7: Steps for Planning for the Future

While there is some ambiguity in the timeline, the risk is too high to wait until reliability is no longer adequate for high electrification, or until you no longer have the tools to manage a more dynamic power flow. A measured approach to making DA investments over time is more responsible. Although you cannot predict when changes will occur, you can prepare for likely future scenarios.

Given this, the following are some recommended steps:

1) **Sustainable Progress:**
The best foundation for a DA program is to incorporate DA investments into each annual workplan. Develop a plan in which you are able to add automation to the main paths of your feeders over a 10 to 15-year timeframe. On lines that have tie points to other feeders, upgrade several hydraulic reclosers to solid-state reclosers with IED controls and automate tie points. Perform hosting capacity studies and plan for Volt/VAR upgrades to segments that would benefit.

2) **Measured Innovation**
Dedicate a percentage of your DA investment to new technology, with the majority focused on foundational and proven technology. Allocating 5 to 10% of your DA investment to grid edge devices or new sensors will allow you to learn about these technologies and decide over time if any rise to the value of broad adoptions.

3) **Strategic Communication**
As you increase the amount of DA on your system, you can separately evaluate what type of communication is most appropriate for your territory and when bringing data back provides the most value. Creating a strategic communication plan can help you decide what options to consider, how much the investment will be, how frequently it may be refreshed, and when to start.

4) **Operational Evolution**
Evolve your operational procedures as you deploy equipment to the field. Progress through steps on increasing visibility to what is happening on your feeders to operator assistance for field activities before considering controls that are initiated by operators or software. Begin building familiarity, in order to build trust and learn what works well.

Incorporating distribution automation into your system and processes is a very achievable goal, if done so in a measured manner. Plans will evolve, but starting with a plan will help you see how expectations are changing and how your cooperative is growing over time. ■

ABOUT THE AUTHOR

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QUESTIONS OR COMMENTS

- David Pinney, Principal-Analytical Tools & Software Products, NRECA Business and Technology Strategies, **David.Pinney@nreca.coop**
- To find more resources on business and technology issues for cooperatives, visit our **website**.

ANALYTICS, RESILIENCY AND RELIABILITY WORKGROUP

The Analytics, Resiliency and Reliability (ARR) Work Group, part of NRECA's Business and Technology Strategies department, is focused on on current and future data and research required to provide prompt technical and economic support to the NRECA membership. Specifically focused toward the electric co-op community, ARR products and services include: development and maintenance of a portfolio of energy analytics products and services; collection and analysis of data; and provision of additional products and services in the areas of the data collection, IT architecture, sensors, and energy markets. For more information, please visit **www.cooperative.com**, and for the current work by the Business and Technology Strategies department of NRECA, please see our **Portfolio**.