Business & Technology Surveillance

An Evolution into ADMS for a Changing Landscape

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?

The advanced distribution management system (ADMS) product category has become well-defined, and there are multiple offerings on the market that offer various benefits, such as restoration management, full system visibility, and Volt/VAR optimization.

WHAT IS THE IMPACT ON ELECTRIC COOPERATIVES?

ADMS enables new distribution management capabilities for mitigating outage impacts and enhancing the visibility into and control of distribution assets.

WHAT SHOULD CO-OPS KNOW/DO ABOUT IT?

It would be beneficial for cooperatives to become familiar with emerging ADMS capabilities, assess whether these are useful to your cooperative, and consider the steps that could be taken to acquire these capabilities (via distribution automation deployment, networking, system integration, and cybersecurity hardening).

A NOTE ON DERMS

ADMS and DERMS technology are both evolving platforms and can share many functionalities. NRECA is monitoring developments in both areas, and providing technical surveillance for our members as feasible. Please visit **cooperative.com** for updates.

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Executive Summary

Recent federal funding for Smart Grid and increased plans for renewable energy on the distribution system have a lot more people talking about "ADMS" and wondering if its right for them. An advanced distribution management system (ADMS) brings the power of automation to distribution utilities that previously only transmission operators had. Informed by interviews with major ADMS vendors and a survey of cooperatives, this article describes ADMS technology available today, where cooperatives are at and what they are focusing on, and how to migrate to an ADMS.

Surveys of cooperatives ranging in size from less than 1,000 to more than 100,000 meters showed that technology is increasingly being used to control their distribution systems, with 80% of surveyed cooperatives having supervisory control and data acquisition systems (SCADA), 75% having SCADA coverage of a majority of their substations, and over 50% having SCADA communication to feeder devices.

ADMS is an evolution of distribution automation technology. At its foundation lies the SCADA system, which is used for monitoring and controlling substations and feeder equipment. ADMS typically adds outage management systems (OMS) for managing crews and communicating with customers during outages, and distribution management systems (DMS) for automating restoration, managing voltages, and using maps to visualize the system.

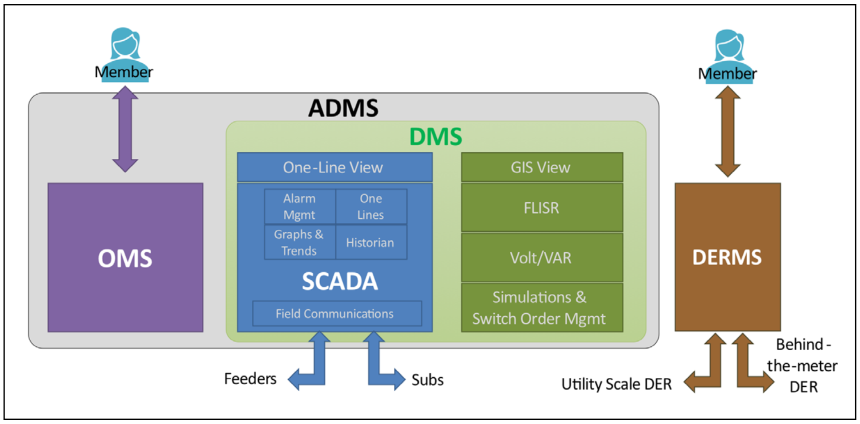

FIGURE 1: ADMS—An Evolutuion of Distribution Automatic Technology

ADMS provides tools for utilities to better manage a dynamic distribution system, in light of increasing renewables and increased electrification. Co-ops surveyed indicated the value they primarily see includes:

- **Restoration**: Improving speed and efficiency of restoring service, especially in light of increased reliance on electricity as a source of energy for vehicles.
- **Visibility**: Seeing the locations of renewables and elective vehicles (EVs), and showing the impact of these to distribution operators.
- **Distributed Energy Resources Management Systems (DERMS)**: Having tools that can address traditional demand response, as well as provide visibility into and aggregate, optimize and dispatch broader DER across the system.
- **Volt/VAR Optimization**: Having tools that can manage voltage and VAR flow in a more dynamic environment.

By making small steps to build on where you are at today, cooperatives can incrementally realize the benefits of ADMS. Focus, simplicity and training are keys to keeping the transition to ADMS manageable.

- **Focus**: ADMS systems are a collection of modules with a broad range of functionality. Start with the component that brings you the most value and build on the lessons you learn from that.
- **Simplicity**: ADMS systems can operate on data models, such as GIS, and integrations that range from simplistic to elaborate. Start with simplistic models to build comfort within your cooperative and expand from there as you learn.
- **Training**: Vendors are very capable of guiding your team through the deployment. Using the deployment as an opportunity to train your staff well is essential for leveraging the ongoing benefit of an ADMS.

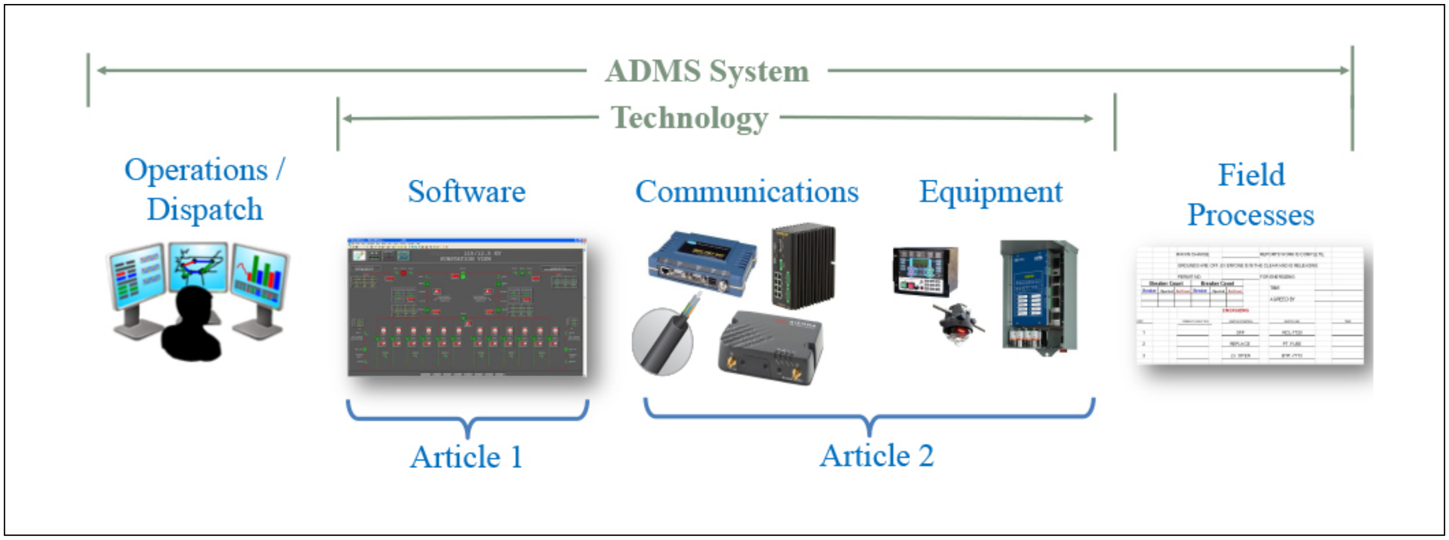

FIGURE 2: High-Level View of an ADMS

Getting Your Bearings

ADMS is often used as an umbrella term that includes the people, processes, software, equipment, and communications required. But, as shown in Figure 2, this article focuses on software.

As functionality extends from the substation to the field, the field equipment and communications become even more important, in addition to the processes dispatchers and field crews use to interact. A second article in this series will focus on those components.

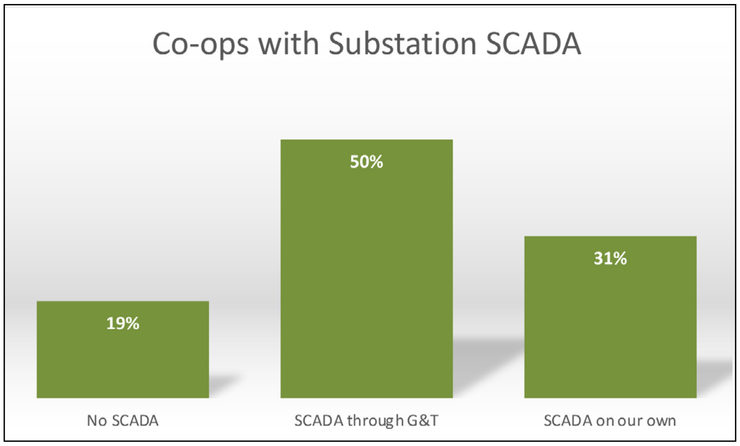

FIGURE 3: Breakdown of SCADA at Cooperatives

Cooperatives across the country were surveyed to provide a picture of peer perspectives toward ADMS. The co-ops were asked what they are doing today for SCADA and ADMS, as well as their vision for the future. This article includes snapshots from the 65 respondents, whose co-ops ranged in size from less than 1,000 to more than 126,000 meters.

SCADA for substations is a starting point for any utility looking to implement an ADMS. Figure 3 shows that 80% of co-ops responding to the survey have SCADA to their substations today.

Evolution of Functionality

The story of ADMS is one of evolution. For many years, utilities have used SCADA for insight into what is going on in their substations and for remotely controlling the devices inside of them. The **Figure 4** shows that 75% of co-ops responding to the survey have SCADA to a majority of their substations.

To help locate, analyze, and restore outages, most utilities rely on an OMS—and as they look to monitor and control equipment on their feeders more directly, they add a DMS.

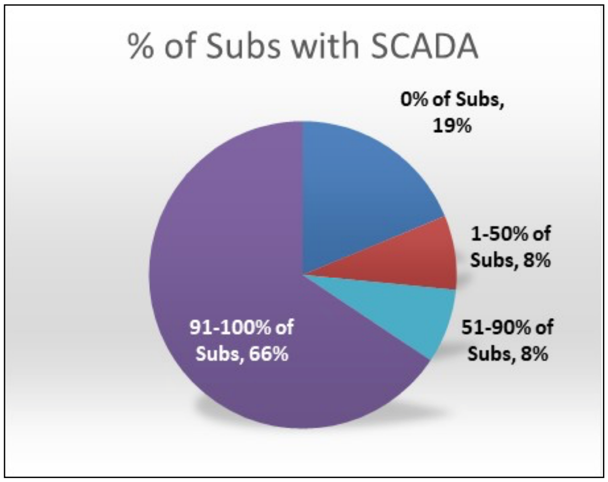

FIGURE 4: SCADA at Co-op Substations

The evolution of these systems has culminated in ADMS, a term that is used broadly to encompass a range of software capabilities. While many in the utility industry provide their own definitions for ADMS, the diagram in Figure 5 defines what we consider to be included in ADMS.

For the purposes of this article, ADMS refers to a single software solution that incorporates the processes, data, and functions of SCADA, DMS, and OMS together. Additionally, the DMS component of ADMS covers a broad range of software technologies from fault location, isolation, and restoration (FLISR) for automating restoration to volt-VAR optimization (VVO) for managing voltage levels. Often included in the discussion are emerging technologies such as a distributed energy resource management system (DERMS) for managing renewable energy resources, both member-owned assets behind the meter and utility-owned assets in front of the meter.

To better understand the evolving role of ADMS in the electric utility industry, a representative sample of four leading ADMS vendors used by cooperatives were interviewed—Minsait Advanced Control Systems (ACS), Open Systems International, Inc. (OSI), Survalent, and Schneider Electric—and their insights incorporated throughout this article.

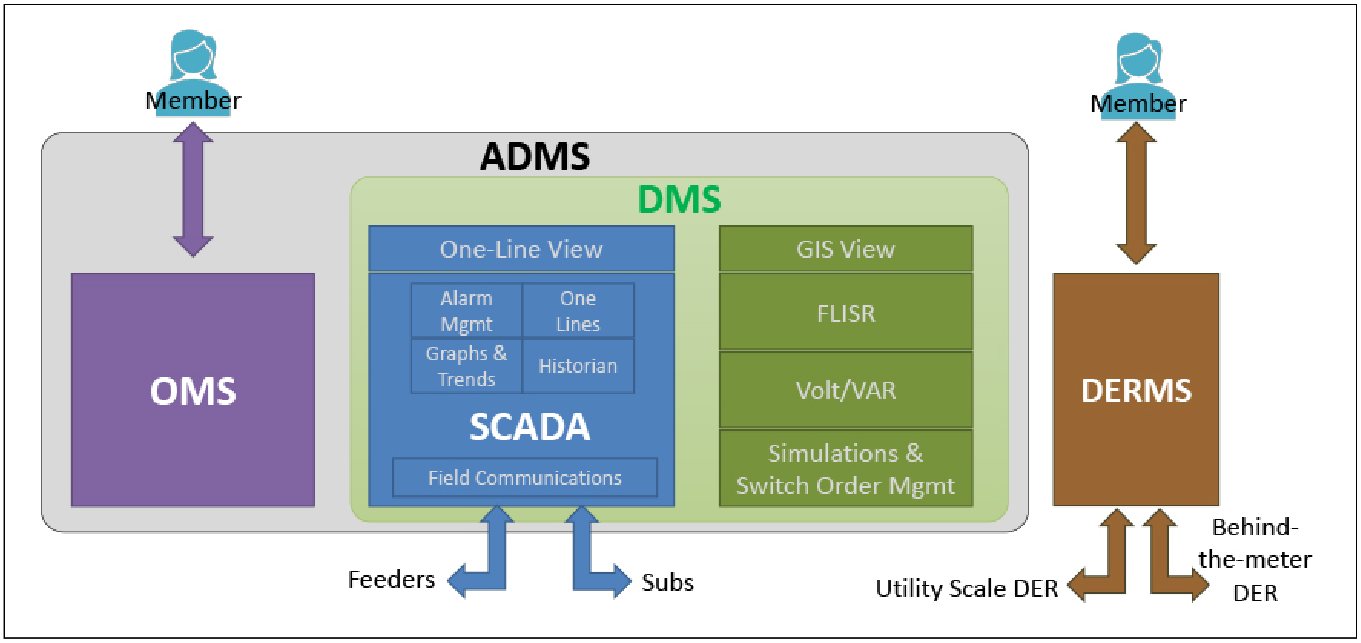

FIGURE 5: Major Components of an ADMS

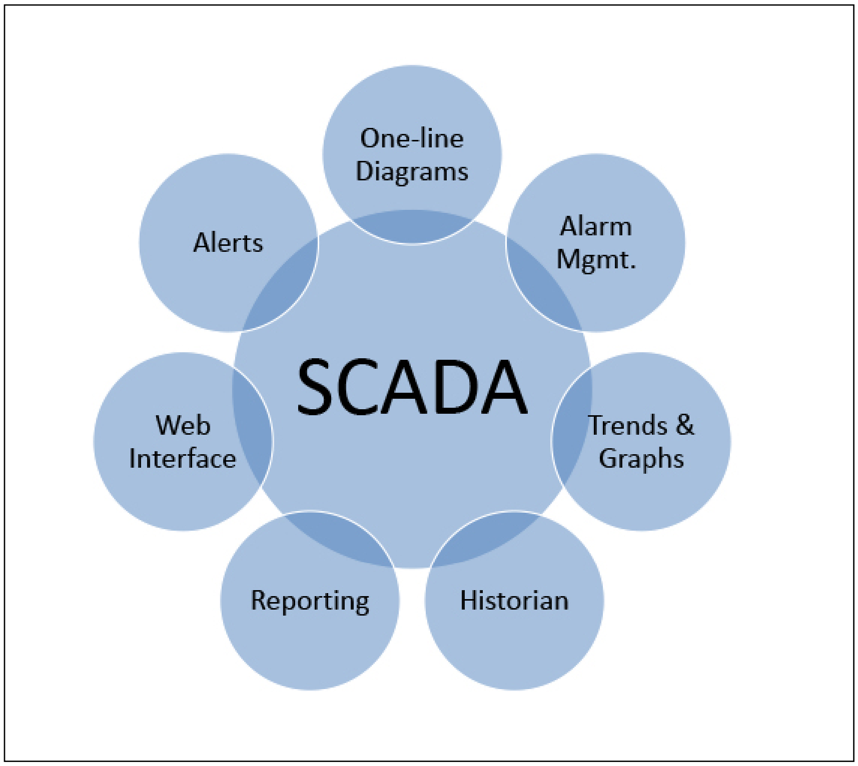

FIGURE 6: SCADA Software Components

SCADA—The Core of ADMS

The heart of ADMS software is SCADA software, which traditionally has been used to monitor and control substations.

Technology has evolved well beyond the simplistic SCADA software from the 1980s and 1990s. However, all the foundational SCADA functionality remains: the systems provide one-line diagrams of substations and whole electric systems, process alarms from the field, allow operators to control equipment, and keep historical records of events and user actions. See Figure 6.

Modern SCADA software has seen additional improvements in alarm management, the ability for some historians to store data as it is received, the ability to view real-time and historic data at the same time, visibility beyond the control room with web interfaces that look just like control room screens, and notifications via email and texts to personnel.

OMS and DMS—Essential Additions

Two major components are added to SCADA to make it into an ADMS: DMS and OMS.

- **Distribution management system (DMS)**: Software functionality designed specifically for visibility and control of the distribution system from the substation to the customer meter.
- **Outage management system (OMS)**: A software system primarily used to identify the location of outages, notify members of the status of those outages, and coordinate crew activities to get the outages restored.

Many utilities today have separate software systems for OMS and SCADA. Additionally, though much less common, some utilities that have implemented DMS functionality have done so with software that is separate from their SCADA. This is most frequently true when the DMS functionality, such as automating restoration, is done through the coordination of relays and/or recloser controls themselves.

DMS and OMS systems both look to manage distribution feeders. They each require a model of the feeders, and both provide an interface for operators in the control room to manage the feeders. Because changes to the distribution system impact both DMS and OMS, there is value in having both in a single ADMS platform.

DERMS—An Increasingly Important Complement

An additional component, a distributed energy resource management system (DERMS), is increasingly included in the discussion with ADMS, though not necessarily an essential component of one.

For many years, a demand response management system (DRMS) was used to do simplistic on/off control of in-home devices, such as water heaters and A/C units, disabling them to reduce demand at peak times. With rapid expansion of in-home technology to include distributed energy resources (DER), like solar and battery storage as well as electric vehicles (EVs), the software has evolved to DERMS, which is used to manage a complex interaction of behind-the-meter resources, as a portfolio of energy resources.

While the behind-the-meter equipment controlled by a DERMS is connected to the distribution system through the meter, ADMS today focuses on control of the distribution feeders more directly. While most ADMS vendors provide some DERMS functionality, capabilities vary significantly. Many vendors who provide a standalone DERMS system provide much broader capabilities than ADMS vendors with DERMS modules. Carefully considering the role that behind-the-meter resources will play in managing your distribution system is important when deciding on an approach for ADMS and DERMS.

In speaking about their approach to DERMS, Brandon Horne, Business Development Manager at Schneider Electric, shared: "We think of DERMS as a holistic approach from the grid to the prosumer. DERMS is a utility-wide transformation. When considering DERMS technologies, it is important to ensure those solutions encompass the needs of all the different areas within a utility, from managing impacts on the grid to engaging with your members."

Why Migrate to ADMS?

While technology has evolved to include a new range of new systems and functionality, not every new capability will be a good fit for your cooperative. Implementing any new technology requires the dedication of capital, human resources, and process change. Understanding whether ADMS makes sense for your cooperative, which components are the most valuable to implement and when, are critical questions to consider.

Substation SCADA and OMS have been adequate for many years, and some cooperatives have yet to deploy SCADA. So, why would cooperatives be considering ADMS? The biggest driver is a desire to prepare for changes in the industry and the associated expectations of members, particularly to meet the evolving needs of renewables and electric vehicles.

- **Distributed Generation**: Residential, commercial, and utility-scale solar, storage, and fossil backup units are increasing on cooperatives' systems as a result of legislation and customer desire. This adds variability that had not existed before in power flow and hidden sources of generation. These resources also present new opportunities for cost-saving demand management.
- **Electrification and Electric Vehicles**: Members are increasingly expecting electric system reliability to meet the needs of electric vehicles, and those EVs are causing rapid changes to load profiles.

The DMS functionality of ADMS allows cooperatives to respond to much more dynamic loads and generation. In much the same way that transmission system operators (TSO) manage a dynamic grid, future distribution cooperatives may play a role of distribution system operators (DSO), managing a dynamic distribution system. Figure 7 depicts the evolution of capabilities with ADMS.

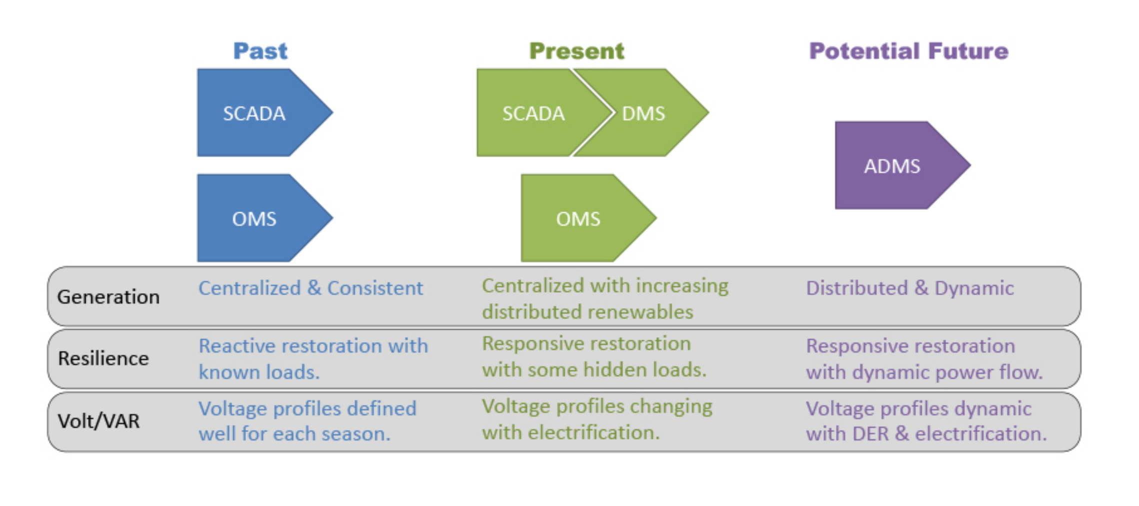

FIGURE 7: The Evolution of Capabilities Available Through Various Systems

Young Ngo, Chief Technology Officer of Survalent, underscored the value, saying, "ADMS and the components of ADMS allow cooperatives to leverage an increasing number of intelligent devices, including batteries, storage, and EVs, and ultimately provide greater satisfaction to their members. ADMS allows cooperatives to provide a new business model for whoever wants to participate in the grid and to modernize their grid."

In addition to its benefits, DMS also adds complexity for operators who now have independent OMS and DMS systems modeling feeder behavior in parallel. While the two systems can be integrated so that operations do not have to be duplicated, utilities looking for a single user interface for feeder management are considering ADMS.

DMS Capabilities

The DMS components included in ADMS are modular, so each cooperative should carefully consider which functions are important to meet their objectives. Figure 8 shows the primary objectives of DMS interest from survey respondents.

To structure the conversation, it is valuable to categorize the functionality that can be achieved from DMS modules. The following sections group the discussion into functionality related to 1) restoration, and 2) voltage and VAR optimization.

1. RESTORATION RELATED COMPONENTS

- **Fault Detection, Isolation and Restoration (FDIR) or Fault Location, Isolation and Service Restoration (FLISR)**: FLISR modules communicate with feeder equipment to detect when faults occur, determining which devices the fault is between, by identifying which have and have not seen the fault. Once the segment is identified, FLISR can isolate the faulted line segment, restoring service to members by transferring them to adjacent circuits.
- **Fault Location**: Separately, by reading fault currents from an electronic relay, the software module can perform power flow calculations on the electrical model of the feeder to determine which span of wire was damaged to create the fault (i.e., where a tree or animal touched the wire) to direct crews to the location more quickly. While many relays offer fault distance information, that distance is based on a simplified estimate of the feeder impedance and cannot account for multiple wire sizes and taps.

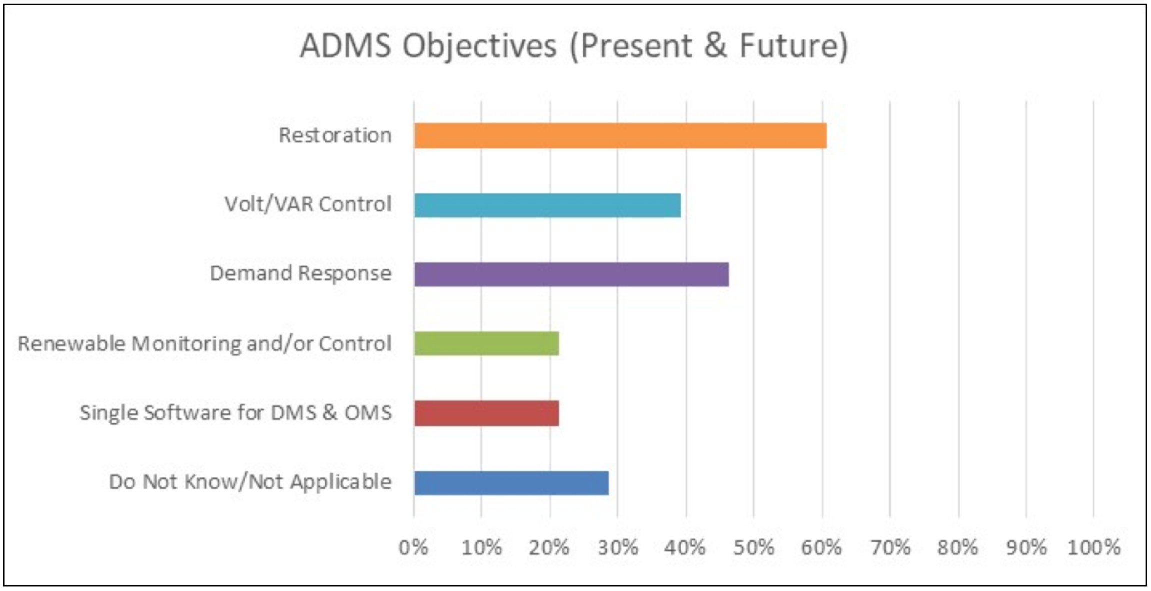

FIGURE 8: Primary Objective of DMS Interest Among Cooperatives

< PREVIOUS VIEW >

- **Rotational Load Shedding**: Load shedding modules use prioritized lists of circuits to select the least detrimental way to reduce demand during emergency events. They cycle through circuits, balancing the time that any one circuit is out of power, while staying below allowable demand values.
- **Switch Order Management (SOM)**: SOM modules assist operators in building and tracking execution of switching orders. They track regardless of whether the devices are communicating with SCADA. Some vendors offer mobile tools for crews to update progress of executing the switch order directly from the field.
- **Simulation**: Simulation allows operators to test what-if switching scenarios. Simplistic simulation verifies that all circuits remain energized and that no portion of the system is overloaded. Advanced simulation performs full power flow modeling to determine voltage profiles on the feeder. Ten percent of survey respondents indicated that they use their software for testing switching orders.
- **Solar Estimation**: As penetration of solar and battery storage increases on feeders, the measured load at the substation is only a fraction of the actual load, with behind-the-meter generation accounting for the difference. Given the practical limits of communicating continuously with a large number of inverters, many vendors support continuous estimation of solar generation on a feeder. Based on interconnect locations, these systems use meteorological data to estimate irradiance and, therefore, generation.

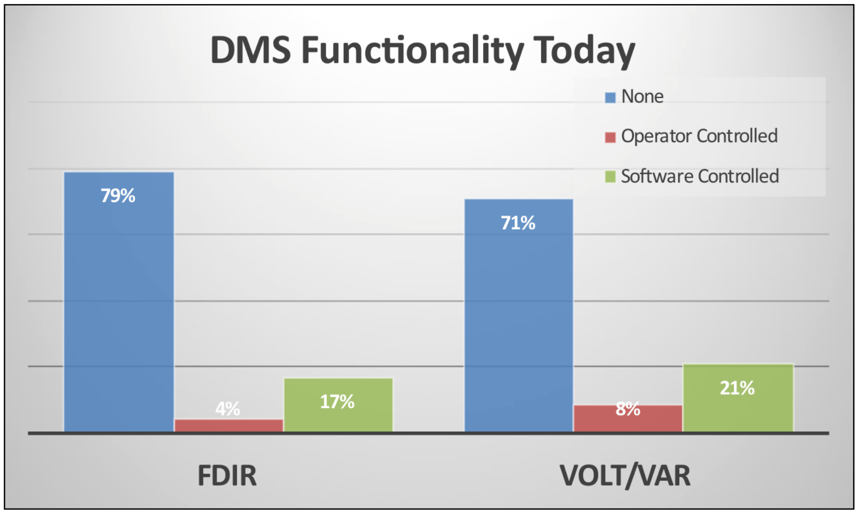

FIGURE 9: Status of Co-ops Implementing FDIR and Volt/VAR Optimization

2. VOLTAGE & VAR OPTIMIZATION COMPONENTS

- **Volt/VAR Optimization (VVO) or Integrated Volt/VAR Control (IVVC)**: Maintains acceptable voltage levels throughout the feeder, in addition to other objectives, such as power factor correction, loss minimization, energy efficiency, and peak demand shaving. VVO minimizes voltage regulator and capacitor bank operations to limit wear and tear, especially in the event of voltage fluctuations caused by high penetrations of solar photovoltaic (PV). Future deployments can increasingly incorporate the capabilities of inverters to manage reactive power on feeders as well.
- **Conservation Voltage Reduction (CVR)**: CVR uses regulation devices to continuously optimize voltage. It can produce energy savings by minimizing voltage within acceptable limits. CVR often works with VVO/IVVC to control capacitors to maintain acceptable voltage profiles.
- **Demand Based Voltage Reduction (DVR)**: DVR is a subset of CVR that is enabled only during peak demand intervals to temporarily reduce voltage to reduce demand.

Many cooperatives are now in the process of implementing many of the features described from the objectives above. Figure 9 illustrates where co-ops are today in implementing two major features: FDIR and Volt/VAR Optimization.

As can be seen in this chart, most co-ops have not yet implemented this functionality. A few are performing this functionality by enabling their operators to perform it from the control room. Approximately 20% of respondents have implemented DMS software modules to perform FDIR and Volt/VAR optimization.

How Do I Get to an ADMS?

Transitioning to an ADMS involves careful planning. There are several critical steps that can make that transition more effective:

1. Building Good Data
2. Designing Integrations for Data Quality, Maintainability and Cybersecurity
3. Deploying Field Equipment with Communications
4. Developing Operational Procedures

This article will discuss the first two steps in this list, allowing the second article in this series to cover the preparation of field equipment and communications and operational procedures.

Building Good Data (Models)

Any utility with SCADA can have a DMS. Basic DMS functionality starts very simplistically and can build from that foundation to a highly refined machine. As the graph in Figure 10 shows, over 50% of survey respondents have SCADA communications with feeder equipment today, effectively positioning them with a foundational DMS system.

The most critical step in getting to DMS is how a utility approaches the model that tells the DMS software how the feeders are connected and how they work electrically. The data in the model must be accurate, relevant, validated, and consistent, especially data migrated from legacy systems. Key data from SCADA, GIS, and load models should be kept up to date in real-time or as close to real-time as possible. Additionally, tuning of the models both at time of deployment as well as on-going is critical to be effective. If not, features of an ADMS cannot be fully leveraged and incorrect conclusions could be drawn.

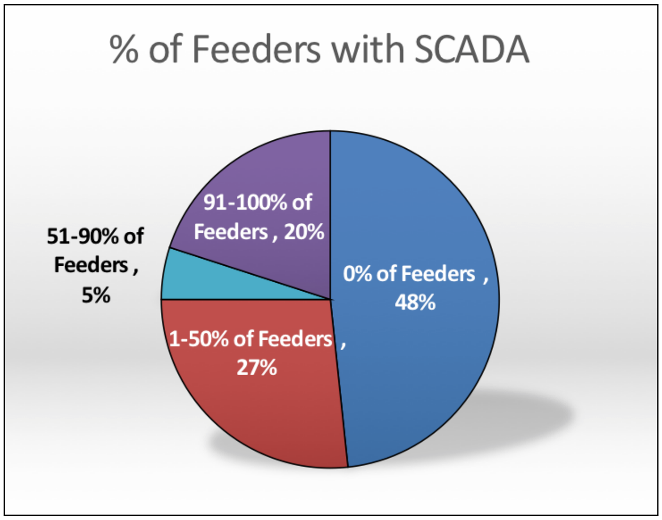

FIGURE 10: Survey Response about SCADA with Feeder Equipment

Cooperatives need to consider the tradeoff between the desired functionality and the complexity of the model required to support that functionality. Several examples that illustrate DMS feeder model complexity and the corresponding level of DMS capability, stepping up from operator-only to a power flow model, are offered in Figure 11 and the accompanying explanation.

- **Operator Only (without Model)**: The operator is aware of how feeder devices are connected to substations and each other, either through experience, by looking at one-line displays build on the SCADA system, or by looking at external maps. In this scenario, SCADA talks to feeder equipment, giving the operator the ability to read information as well as control devices. No additional software modules are necessary beyond SCADA.
- **Logical Model**: Some vendors offer solutions that do not require cooperatives to import a model. Instead, the DMS module is configured to indicate which feeder devices are connected to each other and on the same feeder. The configuration includes basic parameters about the devices to define their limits.
- **Visual Model**: GIS is imported into DMS strictly as a visual layer to allow operators to see the location of field equipment on a map. Equipment points on the map can display telemetered data and be controlled by the operator. Thirty percent of survey respondents with SCADA indicated that they had brought GIS into the system for visualization.
- **Connectivity Model**: GIS is imported into DMS to provide connectivity between all elements in the system. The model can determine which elements are energized and which are de-energized, and can use this information to isolate faults and back feed. DMS is aware of the location of the DER devices.

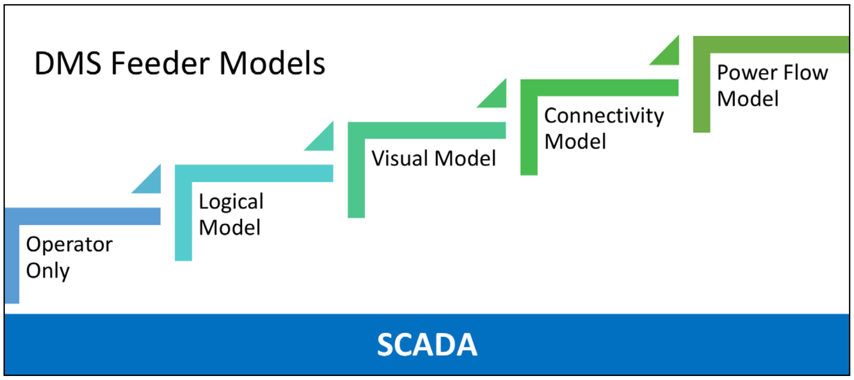

FIGURE 11: DMS Model Complexity and Corresponding Capabilities

- **Power Flow Model**: GIS and a database of electrical parameters of all components (equipment database) are imported into DMS along with load allocation profiles for each meter (or service transformer) location. The DMS can perform power flow calculations including the impact of distributed generation voltage and power profiles and fault location from fault currents.

Giovanni Polizzi, Vice President, Sales & Marketing with ACS, described one of their solutions to stepping into ADMS: "You don't necessarily need to implement a full DMS and have a GIS-based source model. We have a FLISR solution that is template-based and allows the utility to use simple tools to adapt the topology to their system. By knowing just the basic electrical parameters, it can do the necessary load flow calculations to make switching decisions in response to faults. So, they don't have to do a GIS import immediately."

Integration and Cybersecurity

Integration between software systems is key to any deployment of ADMS. The diagram in Figure 12 illustrates integrations between some of the major systems typically included in an ADMS implementation. The systems being integrated span from customer-focused systems which reside on the cooperative's corporate network, to operations-focused systems which reside on the control network. The diagram is colorized to distinguish between systems used primarily for operations and those used primarily for customer and billing.

The diagram, even though it lists 12 different systems that are in common use, is intentionally simplified for illustrative purposes, leaving off many other software systems which interact across a utility.

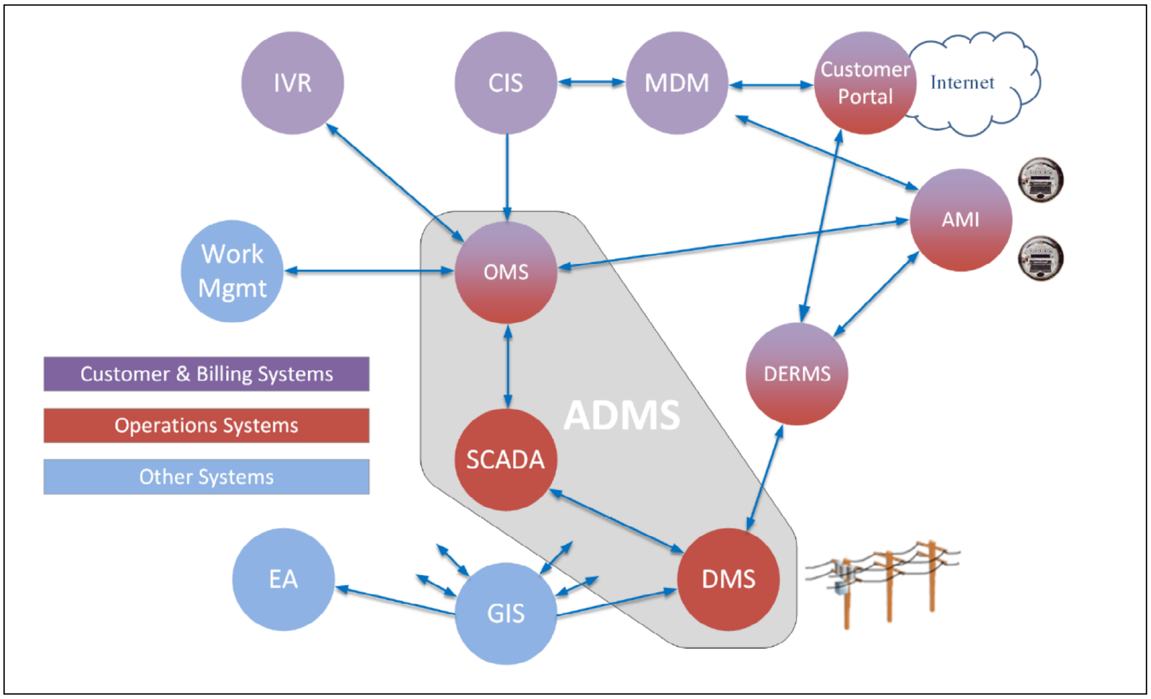

FIGURE 12: Integration of Systems with ADMS

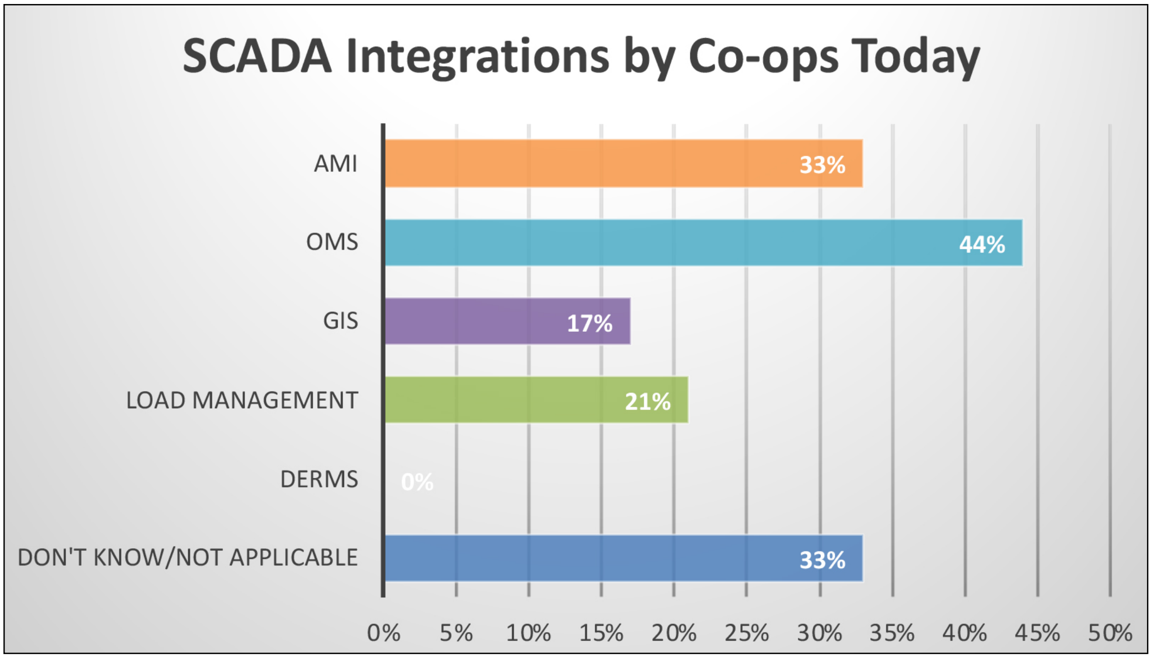

FIGURE 13: Survey Responses Regarding Integrating SCADA with Other Systems

Cooperatives are at very different places in integrating their SCADA systems with other systems. As shown in Figure 13, integrations to OMS and AMI are fairly common. None of the survey respondents indicated that have integrated with DERMS at this time.

When designing your system, it is essential that integrations are both secure and sustainable. Keep the following principles in mind:

- **Segmentation**: Segmenting your operational systems and corporate systems is foundational to a secure ADMS. Fortunately, major ADMS vendors have architected their systems with this mind. The North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) principles identify the need for firewalls for isolation, ensuring that all data connections are initiated from the control network, and use of proxies when exchanging data to avoid data sent externally into the control network.
- **Standards-based**: Avoid custom adapters, which add significant time and cost to ongoing maintenance. Fortunately, **MultiSpeak®** has become the standard for most ADMS integrations. GIS integration is the one interface in which file transfers are still common, though Esri's Utility Network use of web services and a common data model offers a good opportunity to standardize data exchange with GIS.
- **Patching and Maintenance**: Patches are inevitable to respond to changing cybersecurity threats, and it is important to have clearly defined processes in place for upgrading and patching the operating system and ADMS software. Performing these efficiently without affecting the functionality of the DMS is essential. Many utilities are incorporating a platform separate from production for testing patches.
- **Cybersecurity Monitoring and Response Plan**: Monitoring firewalls and endpoint protection on workstations and servers is important for detecting cybersecurity threats quickly. Utilities should plan for systems and staff to monitor and respond to issues, and develop plans for responding to various scenarios.

While integrations and the design of a secure network architecture require detailed attention, most ADMS designers are well-acquainted with how to do so effectively.

In an interview, Hormoz Kazemzadeh, Vice President of Distribution and Smart Grid at OSI, described their attention to security and integration. "We have over 100 utilities that are actively under NERC CIP. We ensure that our ADMS is delivered with the same level of cybersecurity as our transmission systems. To meet NERC CIP requirements, we designed our architecture from the ground up with domains and security zones, and with standards-based integrations and secure interfaces using proxies that "pull" external data into the system rather than allow data to be directly sent/pushed into the system."

Where Should I Go from Here?

ADMS adoption takes time. As the surveys showed, cooperatives' use of technology to control their distribution system is increasing, with 80% having SCADA, 75% having coverage of a majority of their substations, and over 50% having SCADA communication to feeder devices.

The following are some tangible steps for moving toward ADMS:

STEP 1—IDENTIFY WHAT'S MOST IMPORTANT

As you would when responding to any industry change, identify your goals. See Figure 14.

Consider the anticipated growth of renewables and storage on your system. The growth of renewables and increases in electrification, especially from EVs, is likely to ramp up in the coming years, especially given the large investments from both government and private spending.

Considering your system, and especially focusing on areas of the system where you would be more likely to see these increases first, what changes do you want to be prepared for? What capabilities would help you prepare for those changes?

FIGURE 14: Steps Toward ADMS

According to our survey, many cooperatives have a desire for the following capabilities:

- **Restoration**: Improving speed and efficiency of restoring service, especially in light of increased reliance on electricity as a source of energy for vehicles.
- **Visibility**: Seeing the locations of renewables and EVs, and having tools that show the impact of these to distribution operators.
- **DERMS**: Having tools that can address traditional demand response, as well as provide visibility into broader DER across the system.
- **Volt/VAR**: Having tools that can manage voltage and VAR flow in a more dynamic environment.

STEP 2—FOUNDATIONS FIRST

Start where you are at today and build a strong foundation of SCADA communication to intelligent feeder equipment.

Regardless of whether you are working on deploying SCADA or building on an existing foundation you have, this foundation is an essential step in leveraging the powerful tools of ADMS. As an upcoming article on distribution automation will discuss, identifying locations on your feeders where upgrading field equipment is beneficial and then providing communications to that equipment is an important place to start. As you do that, integrate this equipment into SCADA.

STEP 3—BUILD OVER TIME

Start with simple approaches and build on these as your team becomes more comfortable and as the quality of your data model improves.

The ability for operators to monitor and control feeder equipment is a critical first step in building an ADMS future. It gets your team comfortable with the technology and allows you to identify processes to change.

As you are doing this, also improve the quality of your data model, refining the GIS and electrical models of your system.

When adding ADMS software, first add just the modules that achieve the most important goals identified in Step 1, and select modules that aligns with the quality of the models you have. You can start with visualization, logical or connectivity-based models first, and consider building into full power flow models in time as you see value.

ADMS offers many benefits that can help co-ops adapt to increasing demands from renewables and electrification. Using a step-by-step approach can help the transition to ADMS be successful. ■

ABOUT THE AUTHOR

Jim Weikert earned a BS degree in Electrical Engineering from the Milwaukee School of Engineering at Milwaukee, Wisconsin and an MBA from Edgewood College at Madison, Wisconsin. He has almost 30 years of engineering experience in utility and industrial automation and communications. He regularly assists utilities in creating long-term strategies for smart-grid technologies, communications, and data analytics. He and his team then help these utilities in deploying and integrating operations and business systems and the communications that support them. He has a strong background in wireless communications, SCADA, GIS, software and analytics, outage management and work management systems.

QUESTIONS OR COMMENTS

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