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ADMS State of the Industry and Gap Analysis

March 2016

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U.S. DEPARTMENT OF ENERGY

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Summary

An advanced distribution management system (ADMS) is a platform for optimized distribution system operational management. This platform comprises distribution management system (DMS) applications, supervisory control and data acquisition (SCADA), outage management system (OMS), and distributed energy resource management system (DERMS). One of the primary objectives of this work is to study and analyze several ADMS component and auxiliary systems. All the important components and auxiliary systems, SCADA, geographic information systems (GISs), DMSs, automated meter reading (AMR)/advanced metering infrastructure (AMI), OMSs, and DERMS, are discussed in this report. Their current generation technologies are analyzed, and their integration (or evolution) with an ADMS technology is discussed.

Historically, utilities have begun with a single distribution platform function, such as OMS or SCADA, and then added more functions over time, such as DMS, GIS, or AMI from different vendors. This ad hoc process has led to a situation with many non-standard, incompatible databases and software interfaces. An ADMS would include all such platform functions that are available or anticipated, working together as a key smart grid enabler, but this has been a very difficult and expensive proposition. Of 3,000 utilities in the U.S., we estimate that less than 50 have some level of ADMS. Each ADMS project has been a one-off learning experience.

An ADMS technology state-of-the-art and gap analysis is presented. There are two technical gaps observed. The integration challenge between the component operational systems is the single largest challenge for ADMS design and deployment. Another significant challenge noted is concerning essential ADMS applications, for instance, fault location, isolation, and service restoration (FLISR), volt-var optimization (VVO), etc. There are a relatively small number of ADMS application developers as ADMS software platforms are not open source.

There is another critical gap and while not being technical in nature (when compared the two above) is still important to consider. The data models currently residing in utility GIS systems are either incomplete or inaccurate or both. This data is essential for planning and operations because it is typically one of the primary sources from which power system models are created. To achieve the full potential of ADMS, the ability to execute an accurate power flow solution is an important pre-requisite.

These critical gaps are hindering wider utility adoption of an ADMS technology. The development of an open architecture platform can eliminate many of these barriers and also aid seamless integration of distribution utility legacy systems with an ADMS.

Acronyms and Abbreviations

ADMS	Advanced Distribution Management System
AFR	Automatic Feeder Reconfiguration
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
API	Application Program Interface
BPL	Broadband Over Power Lines
BEMS	Building Energy Management System
CAIDI	Customer Average Interruption Duration Index
CIM	Common Information Model
CIS	Customer Information System
CRA	Coordination of Restorative Actions
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DAS	Distribution Automation System
DCA	Distribution Contingency Analysis
DEMS	Distributed Energy Management Systems
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DMS	Distribution Management System
DOE	U.S. Department of Energy
DOMA	Distribution Operation Model and Analysis
DR	Demand Response
DRM	Demand Response Management
DRMS	Demand Response Management Systems
D-SCADA	Distribution Supervisory Control and Data Acquisition
DSE	Distribution State Estimation
DSM	Demand-Side Management
EMS	Energy Management System
ESB	Enterprise Service Bus
EV	Electric Vehicle
FEP	Front-End Processors
FDIR	Fault Detection Isolation and Restoration
FLISR	Fault Location, Isolation, and Service Restoration
FISRCA	Fault Isolation and Service Restoration Contingency Analysis

GIS	Geographic Information System
GUI	Graphical User Interface
HAN	Home Area Networks
HMI	Human Machine Interface
ICCP	Inter-Control Center Communication Protocol
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electrical Engineers
IoT	Internet of Things
IT	Information Technology
IVR	Interactive Voice Response
IVVC	Integrated Volt/VAR Control
LAN	Local Area Network
MDMS	Meter Data Management Systems
Meter HES	Meter Head-End System
OpenFMB™	Open Field Message Bus
OMS	Outage Management Systems
PCC	Point of Common Coupling
PLCC	Power Line Carrier Communications
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
PNNL	Pacific Northwest National Laboratory
POS	Planned Outage Study
PRV	Protection Validation
PV	Photovoltaic
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control And Data Acquisition
SCC	Short-Circuit Calculations
T-SCADA	Transmission SCADA
UBLF	Unbalanced Load Flow
VVC	Volt/VAR Control
VVO	Volt/VAR Optimization
WAN	Wide-Area Network

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1.0 Introduction

1.1 The Power Grid in the Information Age

The 21st century has brought about significant technical advances that have impacted the electric power industry. One of the most significant changes involves increasing levels of deployment of network-connected sensors, devices, and systems – the components of a "smart grid." These new incarnations of the traditional devices include not only the ability to communicate with each other and/or a centralized control system, but sufficient computation resources to execute some degree of autonomous or coordinated control in addition to being centrally controlled. Previously, distribution system operators used a limited set of data from field measurements (most coming from the substations with little to no data "outside the [substation] fence") to estimate the condition of the network and respond to any abnormal situations. The new generation of communication-enabled devices is dramatically changing this, providing volumes of data multiple orders of magnitude higher than previously possible. It is the Internet of Things (IoT), the trend of connecting all our devices (refrigerators, ovens, etc.) to the Internet to enable better monitoring and control, come to the operations of one of today's most critical pieces of infrastructure, the power grid.

The utility industry is transitioning from being late adopters of technology to early or mid-adopters. This transition is being driven by a need to adapt to increased penetration of distributed resources (energy storage, solar PV generation, etc.), the deployment of connected components, changing regulatory environments, and a desire for greater reliability and resiliency. The change in technology adoption is affecting not only the frequency with which equipment is replaced, but also how it is integrated and used. Increasingly, higher levels of integration are required to achieve the higher level of performance enabled by the increase in system information and control.

Changes in technology adoption are in turn resulting in fundamental changes in utility operations and the inclusion of numerous stakeholders, each requiring various degrees of system integration. Stakeholders often include (but are not limited to) transmission operators, adjacent distribution system operators, third-party power providers, service aggregation providers, market operators, and end-use customers. While changes and interactions with stakeholders have traditionally occurred slowly, an accelerating trend is underway to modernize infrastructure, increase customer satisfaction, and improve efficiency [1]. As stated by one industry expert in [2], "Focusing on transformation will result in better operations at the utility and improved service beyond what can be achieved through technology alone" [3].

The modernization of the nation's electricity infrastructure is occurring as utilities develop a wider set of capabilities in addition to the traditional functions of generation, transmission, and distribution [4]. Their portfolios are extending to installation and management of new hardware such as smart meters and distributed sensors, a wider range of software applications and functions, and broader service offering. As a result, it is now possible for utilities to begin considering the deployment of software platforms that integrate operations across the numerous systems that have typically been loosely coupled or even isolated [4]; because of the large number of distribution utilities in the United States and their many differences, this will occur at different rates in different regions [5].

1.2 Evolution of the Advanced Distribution Management System

Advanced distribution management system (ADMS) is a concept that has been proposed as a solution to the new requirements of the integrated operations environment, which must include multiple stakeholders. Currently, there are partial ADMS systems that fill the gap between current distribution management systems (DMS) and emerging ADMS capabilities but the deployment of a fully comprehensive ADMS has not yet been achieved [4]. As stated by Oracle, if properly deployed, an ADMS platform “speeds cost recovery for Smart Grid investments, delays the need to construct new central generation, and provides a flexible grid-management platform that can accommodate emerging demands” [6].

A common theme in ADMS architectures is that of the “platform”. Vendors often describe their suite of products in terms of a platform or collection of platforms. Additionally, state regulators, for example in New York, talk about elements such as a “distribution system provider platform” [7]. In more common use, consumers are faced with choices of platform for smartphones, such as Apple’s iOS™ and Google’s Android platforms. So, what is a platform in the context of the ADMS?

An ADMS platform integrates multiple systems that could include, but are not limited to, supervisory control and data acquisition (SCADA), geographic information systems (GIS), distribution management systems (DMSs), automated meter reading/advanced metering infrastructure (AMR/AMI), outage management systems (OMS), distributed energy resources management systems (DERMS), energy management systems (EMS), customer information systems (CIS), and meter data management systems (MDMS) [4].The full integration of information and controls across these traditionally non- or loosely-integrated systems is what distinguishes an ADMS platform from a traditional DMS [4]. The ADMS platform offers observability and controllability for reliable, resilient, efficient, and economical operations.

Despite the well-established benefits of ADMS integration, the deployment and adoption of ADMS platforms encounters four major obstacles [4]:

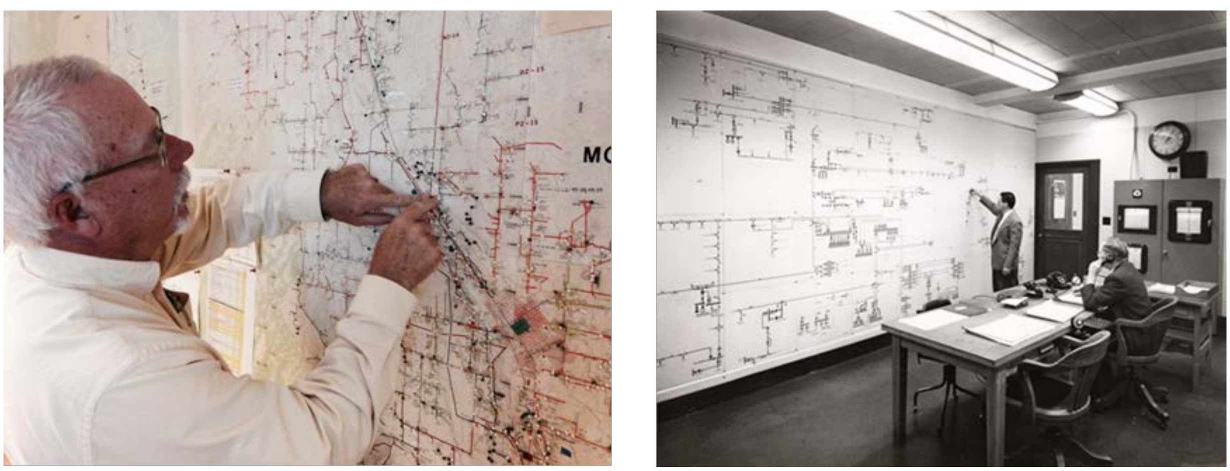
- Complexity of integrating the various systems
- Availability and quality of the data model
- Inability to evaluate and quantify benefits
- Lack of a broad community of vendors to address the needs of utilities of all sizes

As stated in [4], only ten percent of the distribution utilities in the United States operated dedicated DMS platforms with the definition of what constitutes a “DMS platform” varying between utilities. The majority of utilities without a dedicated DMS operate collections of disparate systems used to view and control their electrical infrastructure, having been assembled over the years in an ad hoc manner [4]. Even utilities with a dedicated DMS operate collections of disparate systems that have non-standardized interfaces to the DMS. One of the major reasons for this loose interconnection is that each system often uses its own data models and/or communications protocols, which in many cases are not transportable between vendors. For example, it would be unusual for an OMS from vendor X to be able to integrate with a DMS from vendor Y without extensive and costly integration efforts. This integration is almost always highly customized work and completely non-transferrable to other utilities.

The integration of software and systems is rarely an easy task and there can even be challenges with the integration of systems from the same vendor. The challenges associated with system integration are compounded by long-term system maintenance and upgrade decisions. As systems update and upgrade on different schedules, new issues can arise that affect the organization’s workflows and the interactions between groups. Data and model issues, workflow changes, organizational changes, scope creep, and financial constraints are a few of the obstacles utilities have faced when attempting to deploy ADMS [4].

In addition to the challenges associated with system integration, it can be difficult to evaluate and quantify the long-term benefits of ADMS. Deployment of ADMS is often justified as a business strategy: “an ADMS is not a technology that necessarily cuts costs; it adds capabilities and functionalities to support the company’s long-range vision” [4]. For a project as large and complex as an ADMS deployment, a strategic technology roadmap becomes essential. This roadmap together with the business requirements and use cases are living documents, being visited often, updating to reflect progress, and governed by change-management rules [8].

Once a utility begins to deploy ADMS, in accordance with their roadmap, it will impact distribution system operations; in many cases these changes are the reason ADMS is deployed. The impact of integrated operations can be seen in the methods that have been used to display information in distribution control centers; specifically, in the evolution of distribution system circuit visualization. Early distribution systems used paper-based maps (Figure 1-1a), which eventually were replaced with one-line diagram mimic boards (Figure 1-1b). It should be noted that some smaller distribution utilities do not use one-line mimic boards. An example of a paper map is shown in Figure 1-1(a), where Delta-Montrose Electric Association uses a floor to ceiling map as a backup method of display [10]. An example of a one-line mimic board that is used for routine normal operations can be seen in Figure 1-1(b), which shows an image of a wall map of the electrical system of Public Service of New Hampshire (PSNH) original control center [9].



(a) (b)

Figure 1-1. (a) Delta-Montrose Electric Association uses a floor to ceiling paper map as a backup methods of display [10] (b) Public Service of New Hampshire (PSNH) original control center and its mimic board [9].

The advantage of using large one-line mimic boards is that a dispatcher is able to visually see a single display of the entire service territory. For large distribution systems there may be multiple dispatchers with each responsible for only a portion of the entire system. While these systems provide a degree of situational awareness, they have limited real-time capabilities. Early mimic boards required all changes in system conditions to be manually updated on the mimic board. Later versions of mimic boards began to include some remote indication, but these had to be hardwired and were difficult to maintain. These older one-line mimic boards became a bottleneck in the information dissemination process for dispatchers. Ideally, dispatchers require comprehensive, real-time information, particularly in emergency conditions: the state of the system, where the outages are, which switches are open/closed, which transformers are working or not working, where the crews are working, etc. [2].

To improve normal and emergency operations, utilities have begun to deploy electronic wall boards that have one-line diagrams, similar to the older mimic boards, but with the status automatically updated by various systems. Depending on the particular implementation, and level of integration, the visualizations and status updates typically come from SCADA, the DMS, and the OMS. An example of an electronic wallboard can be seen in Figure 1-3. This picture was taken in the Electricity Infrastructure Operations Center (EIOC) at Pacific Northwest National Laboratory, in Richland WA [11]. In this figure an Alstom DMS is displaying a one-line diagram on the right, with other applications displayed on the left. While the EIOC is not an operational control center, it is designed to visually reflect what is seen in an operational control center.

Figure 1-2. EIOC Electronic Wallboard

Operational electronic wallboards are expected to display information collected from multiple systems, and presented in near real-time [2]. The integration of information for the purposes of display has changed the way dispatchers view their systems. For example, having both the DMS and the OMS information displayed in a single visualization allows a dispatcher to more effectively dispatch field crews, reducing outage times. While this information is integrated for the purposes of visualization, the two systems are not always fully integrated. Specifically, the DMS and the OMS may have similar data inputs that are used for the visualizations, but the DMS and the OMS may not be able to interact directly.

ADMS has the potential to transform all aspects of operations, and not just those related to the visualization of data. Instead of simply bringing data into a common environment, each of the component systems will have the ability to interact with the other systems, issuing commands to other systems. As ADMS implementations continue to become more common and their capabilities increase, the level of integration across systems is similarly expected to increase.

1.3 Report Objectives and Outline

The objective of this report is to provide an overview of the component systems that can be integrated for an effective ADMS deployment, including a selection of various vendors and their technologies. This report also emphasizes the challenges with developing the data models necessary to take advantage of an ADMS. The integrated systems of an ADMS platform requires a number of models that include:

- **As-built** models representing the normal configuration of the system [12],
- **As-operated** models representing the system’s current configuration reflecting also the temporary changes [12],
- **As-planned** models representing inclusion of the planned facilities extensions into the as-built and as-operated models, once the devices are active [12].

This document discusses the state of the industry in three areas. First, each of the major tools classes that are used for distribution operations is discussed. This includes SCADA, GISs, DMSs, AMRs/AMIs, OMSs, and DERMSs. Second, the current generation of ADMS technologies is discussed. And third, an analysis of the current gaps in ADMS is presented.

Sections 2 through 7 of the document present a consistent structure for presenting each of the ADMS component systems. This includes a description of their functionality, a diagram of their potential connectivity with other systems, and the data exchanges taking place. Also, for every component system, a selection of various vendors and their product offerings is presented, a discussion on the current trends, and strengths and weaknesses of each are reported; all information on vendor products are reported from either vendor website, or utility websites. Section 8 reviews the challenges that ADMS deployments have had, and examines why the transition from DMS to ADMS has proven to be challenging. The final section will also identify areas where work is needed to bridge the gaps between today’s technology and the ADMS systems of the future

2.0 Supervisory Control and Data Acquisition

Supervisory control and data acquisition (SCADA) systems consist of software and hardware systems that monitor, collect, and process data. SCADA is commonly used in many industries, and is not unique to electric power systems. The term SCADA was conceived in 1970s, and was used to describe systems that monitor and control automated processes. In the decades following its development, SCADA capabilities increased with the introduction of local area networks (LANs), which increased the ability of SCADA to be interconnected with other systems. The introduction of modern information technology (IT) standards and web-based applications within SCADA software has improved the functionality and interconnection ability of SCADA systems. The addition of human machine interface (HMI) has increased the usability of SCADA, contributing to its widespread deployments. In electric power systems, modern SCADA systems allow near real-time data from substation and field devices to be monitored and controlled remotely by systems such as DMSs and OMSs. SCADA data is typically updated at a rate of once every 2-10 seconds and can be archived, allowing for trend analysis and the ability to analyze past power system events [8].

2.1 Functionality of SCADA

A modern SCADA system for electrical power systems consists of four types of components: measurement/control devices, interfaces for the measurement/control units, a communication network, and a SCADA host. Figure 2-1 presents the dependencies between these four components, along with a data historian for archiving and analysis. Measurement devices monitor system parameters (such as voltage and current) and control devices have the ability to execute control functions (such as opening a breaker or recloser). The measurement sensors and control devices are interfaced with units to provide access to the communications network. In earlier SCADA systems devices were individually and directly connected to remote terminal units (RTUs), which interfaced to the broader communications system. RTUs are in currently being replaced with the more general intelligent electronic devices (IEDs). IED technology has advanced to the point where newer substations typically do not have dedicated RTU's. Instead, the measurement and control devices themselves are fully enabled IEDs with each device connecting directly to the communications network. The SCADA host is also connected to the communications network and processes the data from the various RTUs and/or IEDs, making the information available to the system operators. Additionally, the SCADA host processes command signals from the system operator and sends these to the appropriate RTU/IED. Most of the commercially available SCADA systems have the ability to categorize and prioritize this gathered data and provide display and alarm functions. It is also possible to accurately synchronize time and to time-tag events. Advanced event logging, analysis, and filtering of data helps utility operators to locate exact information thus enabling effective data collection [8], [13].

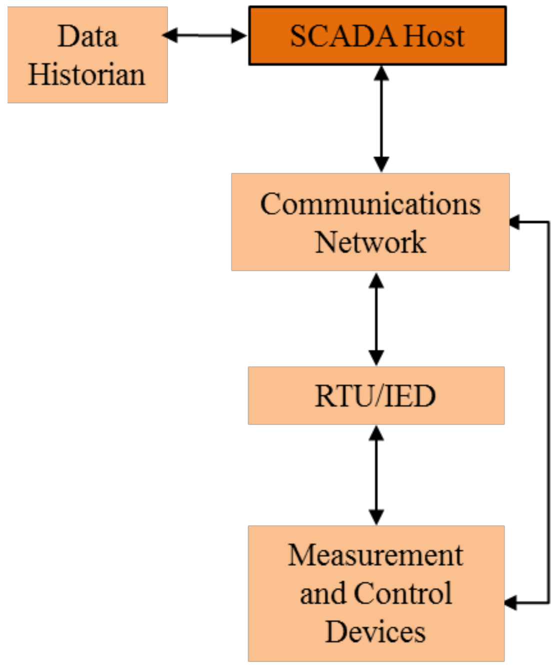


Figure 2-1. Representative SCADA System Data Measurement and Communication [8]

2.2 Functionality Diagram

In a power distribution system, data is collected from the variety of field devices, with some devices also being control devices. For example, a shunt capacitor may provide voltage magnitude values and have the ability to be opened or closed from the DMS. Depending on its size and complexity, a substation and its associated distribution feeders can have a number of measurement points and controllable devices. In a new substation, each of the measurement and control devices are typically IEDs and are connected to the communications network, typically the substation LAN. The substation LAN then connects to the enterprise communications network, connecting the IED to the SCADA host. There may also be a SCADA host at the substation itself, depending on the specific system architecture. Usually SCADA consists of the following subsystems:

- **Measurement/control devices**: Individual devices that measure data and/or control physical actions. Examples include, but are not limited to, voltage potential transformers, current transformers, breakers, and capacitors.
- **Communications interface**: Devices that connect the measurement/control devices to a communications network. While older RTUs would connect multiple devices to a communications network, newer IEDs have integrated communications interfaces. For example, a programmable logic controller (PLC) may have built-in networking capabilities.
- **Communications network**: Depending on the architecture of the system, there may be one or more communications networks. The function of these networks is to communicate data and control signals between different locations.
- **Data historian:** A historian is a centralized database for logging all distribution system information. Historian typically gathers and archives grid information collected by sensors on a distribution network. IEDs provide distribution system operators with a significant amount of data, which a

historian's data logging and reporting functionality can analyze to generate valuable information for an operator. This enables an operator to take account of present operational scenario and past events. For example, a historian can provide details of loading on various transformers, or a list of triggered alarms.

The above discussion has considered a generic SCADA system, and specific deployments are arranged based on utility requirements and may evolve over time. The SCADA systems typically deployed in the electric power industry can be categorized as either monolithic, distributed, or networked [14]. The first generation of SCADA systems that were deployed by electric distribution companies are considered monolithic systems. These systems were designed in an era when mainframe computing was considered "state of the art." These systems were highly centralized and typically isolated from any other systems. The wide-area network (WAN) protocols they typically used were proprietary and were designed by equipment vendors. With these protocols, no other functionality was possible other than measurement and control of remote devices. Figure 2-2 shows an example architecture of a monolithic SCADA system where each RTU communicates directly with the SCADA host (sometimes referred to as the "SCADA Master"). In this architecture, it is possible for a single substation to have multiple RTUs.

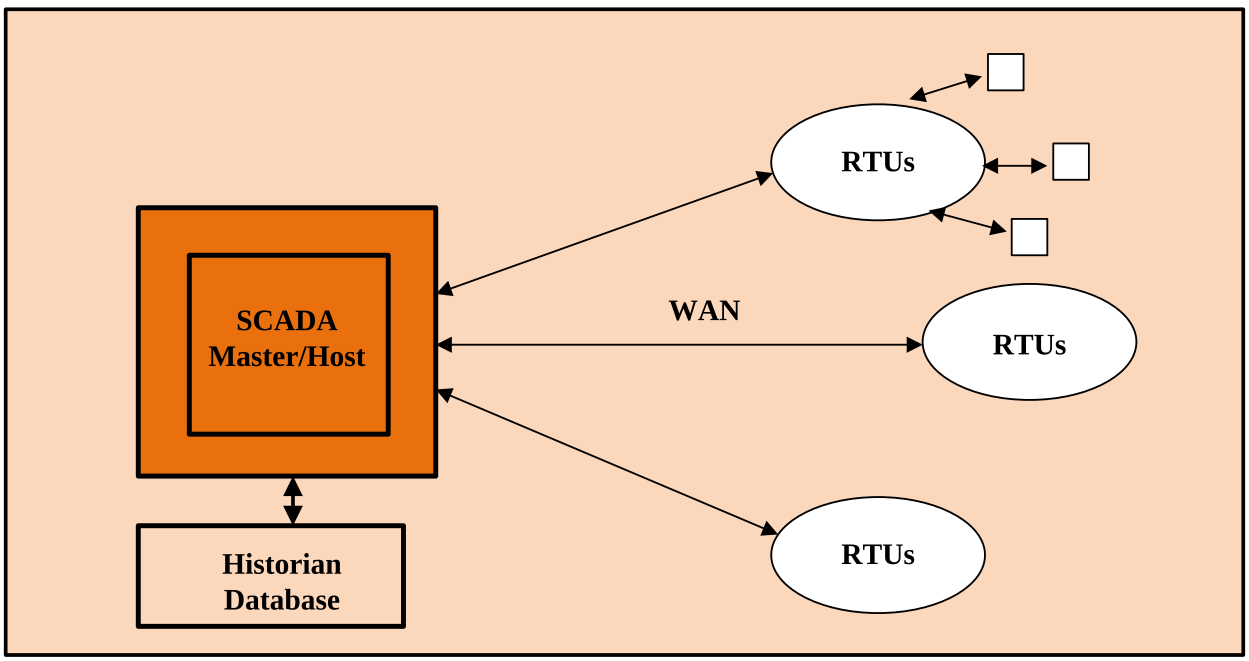


Figure 2-2. Representative Monolithic SCADA Architecture [14]

The second generation of SCADA systems had a three-level control-center hierarchy. These systems are known as distributed SCADA. At the substation, the architecture was similar to the first generation of SCADA, with multiple devices at a substation communicating through one or more RTUs. Instead of the RTUs communicating directly to the SCADA host, though, the RTUs would interface with a communication or front-end server located in the control center. This server was located on a LAN, which could be accessed by internal utility systems, including the SCADA host. Figure 2-3 shows the architecture of a distributed SCADA system. Using a LAN, it is possible for multiple systems to access the SCADA infrastructure. However, the LAN protocols used were typically still proprietary in nature, and limited the ability to interconnect the SCADA system with other utility systems. The external WAN networks were also typically limited to RTU protocols.

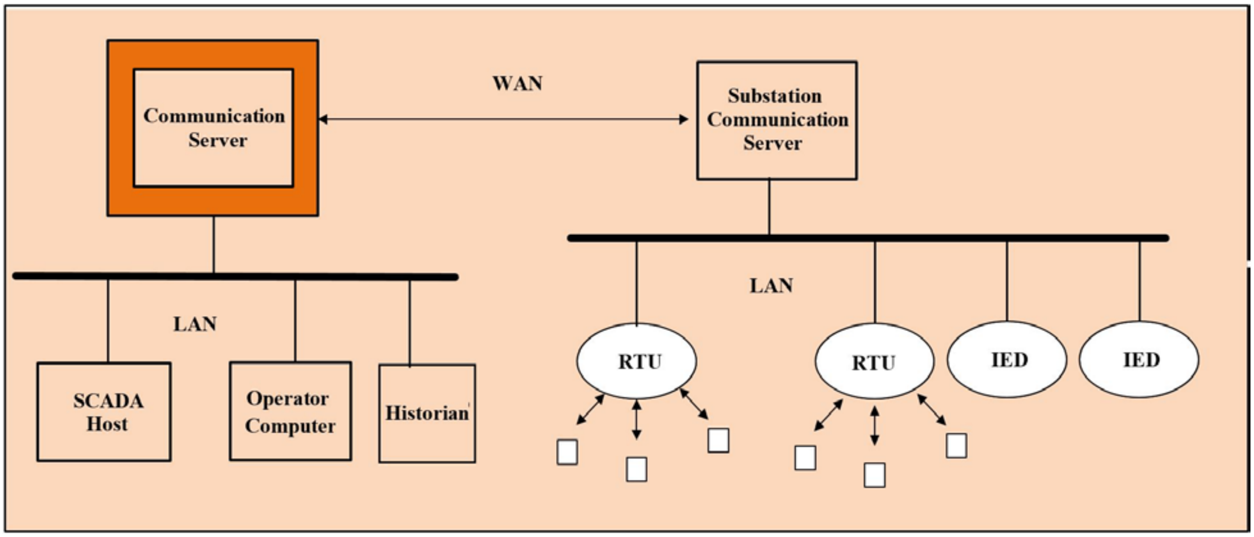


Figure 2-3. Representative Distributed SCADA Architecture [14]

The SCADA systems that are typically deployed in North America today use an architecture that is similar to the second generation distributed system, but with a higher level of networked communication, occurring at both the substation and the control center. In the substation, IEDs are connected directly to the substation WAN, which includes a communications server. The substation communications server is the gateway for an entire substation, and connects to the control center via a WAN. In newer deployments there are even sub-networks for high-speed data exchange between devices. This is referred to as a process bus, and represents a higher level of system integration. At the control center, the role of the traditional SCADA Master has been changed so that the communications is handled by a WAN. This transition to a WAN is possible due to the increased use of open standards and communications protocols such as Internet Protocol (IP). A communications server at the control center connects to a LAN so that multiple systems can access SCADA. While a new substation may follow this architecture, for existing substations it is possible to integrate a combination of IED and legacy RTUs. Figure 2-4 shows a networked SCADA system where there are newer IEDs, with a portion of them using the process bus. Additionally, greater integration at the control center is shown with the OMS also connected to the LAN. It is possible that the control center LAN could have numerous other systems connected as well.

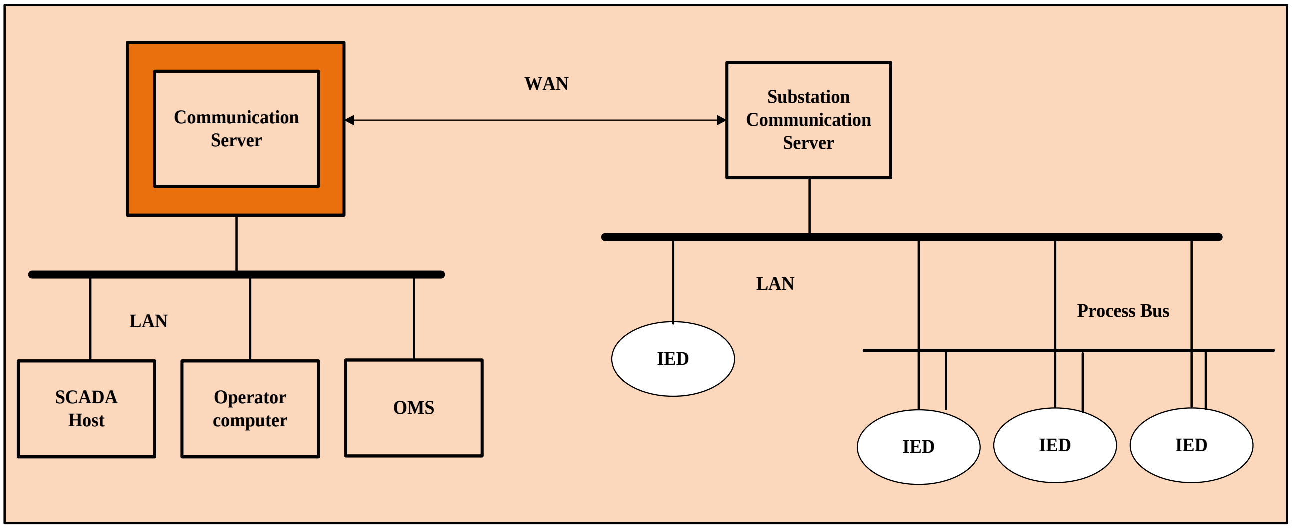


Figure 2-4. Representative Networked SCADA Architecture [14]

2.3 Data Exchange

As was seen in Figure 2-2, Figure 2-3, and Figure 2-4, data in a SCADA system typically flows from field devices to a control center, and control signals are sent from the control center to the field devices. In general, signals and commands are only sent when there is a query from the SCADA master station. The actual data exchange is governed by the implemented communication protocols. Some of the older SCADA systems were developed before the development of industry-wide standards for interoperability. During this period there were numerous protocols developed, many of which were proprietary. In some cases proprietary protocols were developed to incentivize customer loyalty [15]. Common SCADA protocols include Modbus RTU, RP-570, and Profibus. These communication protocols are vendor specific but have been widely adopted and can be found in use in many utilities. Standard protocols recognized by the majority of SCADA vendors include IEC 60870-5-101 or 104, IEC 61850, and DNP3 (which is now also IEEE Standard 1815-2012) [13]. Many of these protocols now contain extensions to operate over TCP/IP. The use of industry standard protocols simplifies system engineering and creates seamless data exchange and communication. Typically, there is redundancy provided to improve fault tolerance and communication system reliability.

2.4 Vendor Details

Table 2-1 presents a selection of SCADA system vendors and their products. While this is not a comprehensive list, it is a representative cross section of SCADA products offered by vendors. The table also identifies which protocols the vendors claim to support. Siemens Distribution-SCADA product uses Inter-Control Center Communications Protocol (ICCP) to connect with other systems [16]. Data modeling in Siemens SCADA systems is compliant with IEC 61970 and uses the Common Information Model (CIM). The MicroSCADAPro product by ABB supports multiple protocols as indicated in Table 2-1 [17]. It is equipped with the OSIsoft PI Historian. PowerOnFusion SCADA system by GE supports DNP3.0, IEC 60870 and has a library of legacy protocols [15]. Most vendors also make available a time-series data historian. The Schneider SCADA systems support Modbus TCP, Modbus UDP, DNP3 WAN/LAN, and

IEC 60870-5-101/103/104 protocols. Most SCADA systems have the capability to access third party databases and most system front-end processors (FEPs) have the ability to be part of the SCADA host software [8].

Table 2-1. Partial List of SCADA Vendors

Vendor	Protocol
ABB [17]	Master protocols: IEC 61850 Ed1 and Ed2, IEC 60870-5-101/103/104, IEC 61107, LON, SPA, DNP 3.0 TCP/serial, Modbus TCP/RTU, ANSI X3.28, I35/P214, RP570/1, ADLP180, etc.
GE [15]	Supports DNP3.0 and IEC® 60870 and a broad range of library of legacy protocols
Schneider [8]	Modbus TCP, Modbus UDP, and DNP3 WAN/LAN, IEC 60870-5-101/103/104 and a broad range of library of legacy protocols
Siemens [16]	Supports DNP3.0 and IEC® 60870 and a broad range of library of legacy protocols
Open Systems International	Supports DNP3.0 and IEC® 60870 and a broad range of library of legacy protocols
Survalent	Supports DNP3.0 and IEC® 60870 and a broad range of library of legacy protocols

2.5 Current Trends, Strengths, and Weaknesses

While SCADA is still commonly deployed as a stand-alone system, it is increasingly being integrated with other systems. The current industry trend is to integrate SCADA with the DMS and/or the OMS, with the majority of operator interactions occurring through the DMS and/or the OMS. In some integrations, the monitoring and control services are supplied by the DMS and/or the OMS vendor(s). In utilities where SCADA existed prior to the DMS and/or OMS deployment then standard protocols are used to integrate the systems. Even when standard protocols are supported by SCADA and the DMS/OMS, integration has proven to be a challenge.

While there are still challenges with integrating SCADA to other systems, modern SCADA systems can take advantage of the common communications protocols, which include Ethernet and TCP/IP. These communications protocols allow SCADA to transmit data from the sensors and control devices on the electric distribution system to a control center where the dispatchers interface via a SCADA front end, the DMS, and/or the OMS. SCADA protocols are no longer closed proprietary systems but are open systems, allowing designers and distribution system operators a greater flexibility [13].

The strength of the modern SCADA systems is that they are able to effectively measure and communicate electric distribution system data to a central location. The advancement in SCADA, and the associated communications systems, has made it possible to monitor a large number of power system variables and to control numerous devices. Additionally, SCADA can provide extensive alarm and monitoring functions that given system dispatchers increased visibility into equipment status and improve situational awareness. While current SCADA systems provide many benefits, there are still weaknesses associated with specific implementations as well as general cyber security concerns.

Because SCADA systems form the primary means of monitoring and control for many distribution utilities, they are tempting cyber targets. While most utilities own and operate their own communication infrastructure, some lease capacity on shared infrastructure. Regardless of whether the communications infrastructure is utility owned or leased, cyber vulnerabilities exist in all systems and these risks must be addressed. In addition to the challenges presented by cyber security, there is no clear consensus on which SCADA protocol is the best. While DNP3 is currently the most common in North America, the IEC 60870-5 series protocols have many advantages, and are beginning to be used more widely. These two protocols have many similarities but are not completely compatible [13].

A facilitation of communication via an open platform is also one of the significant current trends. Open Field Message Bus (OpenFMB™) is an existing standards-based solution that enhances integration with field devices, and enables power systems field devices to interoperate. This standard enables devices to communicate with each other and also with centralized data centers facilitating secure communication among field devices. OpenFMB™ has an ability to reduce proprietary technology dependence [18].

3.0 Geographic Information Systems

Geographic information systems (GISs) are designed to store and display large amounts of geospatial asset data. Asset location information is entered into a GIS by an engineer who physically locates a piece of equipment, or other asset, and enters its spatial location. In addition to the spatial information, equipment specific information can be stored. This information can then be used to display system data in geospatially representative way, enabling a clearer view of the system state.

3.1 Functionality of GIS

Prior to the modern GIS, power companies used paper-based maps to track geospatial information. Keeping the maps up to date was a time-intensive task, and errors could pose safety issues for the workers in the field. Slowly, utilities started the migration toward electronic databases and graphical representations. The modern GIS is typically an off-line tool with data entered by a field engineer or technician (aka "staking engineer"), and the output being used for multiple purposes. In addition to a graphical representation and asset management functions of the early systems, a modern GIS can provide input to the DMS, the OMS, and the CIS [2]. The GIS system and its related asset systems are the key enablers of electronic mapping [2].

The GIS provides five key pieces of data:

- Asset type – is it a circuit breaker, a transformer, or what?
- ID – what is its name?
- Location – Where is it located? Generally, latitude/longitude coordinates.
- Connectivity – what is it connected to?
- Characteristics – what are its characteristics? – e.g., impedance and so on.

For utilities deploying a DMS or an ADMS, the GIS is a critical element representing the "system of record for the as-designed and as-built configuration" [12], providing the network connectivity and equipment information. GIS usage can include optimization of electric line routing, optimal design and location choices for new feeders and substations, as well as establishing the customer-to-network link [19]. Regular GIS updates are integrated into the workflow at most utilities that have one.

3.2 Functionality Diagram

A GIS has the ability to provide information about distribution system assets (poles, conductors, switches, transformers, voltage regulators, etc.), asset attributes (ratings, locations, etc.) and connectivity, as well as asset maps and renderings [2].

The GIS's information accuracy, and subsequently its network model accuracy, is fundamental for all the other systems that rely on the GIS as an input. To provide a representative view of the possible interdependences between GISs and other systems, a connectivity map is provided in Figure 3-1. The connectivity map is a representative system where the DMS and the OMS are interconnected with the GIS so that distribution system model information can be accurately represented. The OMS data can be used to validate and/or cross-check the information provided by the GIS. In addition, a GIS provides the basis for utility planning models. The connectivity map in Figure 3-1 is only a representative interconnection of the GIS, but it highlights how the GIS is an essential component in an integrated system.

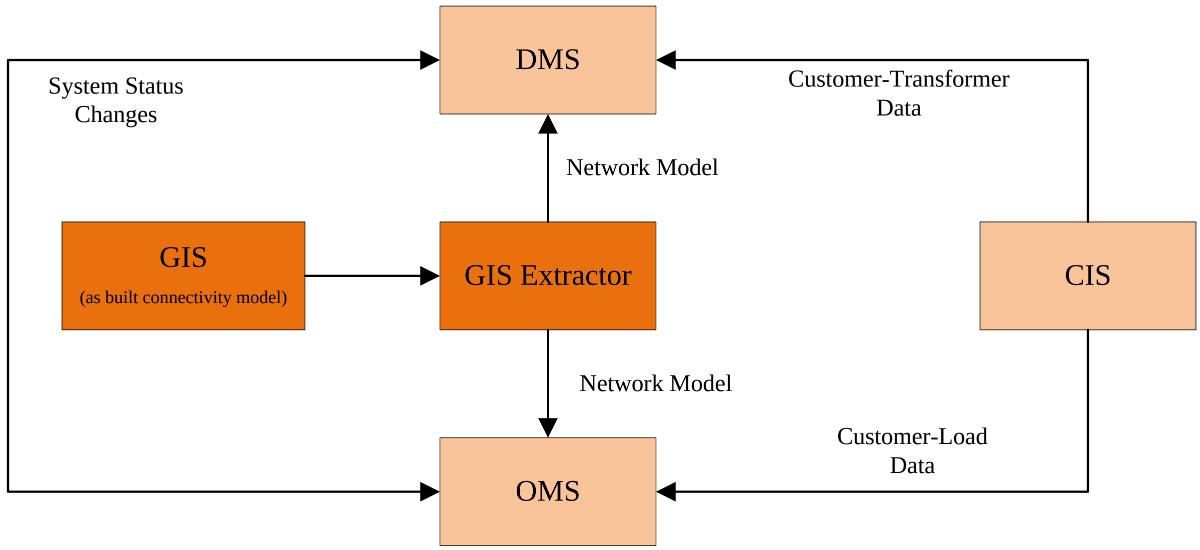


Figure 3-1. Representative GIS to ADMS Interaction Architecture

3.3 Data Exchange

Since the GIS provides the connectivity model and network model for other systems, and leverages its data for financial, work force management and the CIS platforms, inaccuracies in the GIS information may propagate into the other systems. The ability to share the GIS information between engineering, operations and field crews, as well as other groups is a critical requirement for a GIS enterprise system [20].

In an integrated system, the GIS and the DMS systems need to be strongly interconnected and integrated to enable the exchange of large volumes of data [21]. Ideally, the two systems will work from a single common data source. But in some systems there may be two or more data sources that are coordinated. When there are multiple data sources it is possible for discrepancies to occur, especially during abnormal operating conditions. During abnormal operating conditions it is possible that information is updated in only one system, and not accurately reflected in the others. The inaccuracies can be prevented with the use of a single data source, or if there are multiple data sources, they can minimized using standards. The use of standards, such as the CIM, enables information-sharing between systems. Even with the use of standard protocols and data models there can be challenges with integrating the GIS into operational and back-office systems.

3.4 Vendor Details

Choosing a GIS system that is scalable, extensible, high-performing, and also aligns with utility-specific needs and goals is a decision that utilities should make based on the available vendors [20]. An enterprise GIS should grow as an organization grows and as other applications are added. While the basic functions of a GIS will be similar between utilities, the specific implementations can vary greatly. Vendors generally partner with electric utilities to integrate a GIS platform with other utility's systems.

Table 3-1 presents a selection of GIS system vendors and their products. While this is not a comprehensive list, it is a representative cross section of GIS products offered by vendors. This table includes stand-alone GIS platforms such as Oracle [22], and OSI [23], as well as GIS platforms that have been developed in partnerships with utilities.

Table 3-1. Partial List of GIS Vendors

Vendors	Product name	Additional Functionalities
ESRI [24]	ArcGIS	Google Maps Integration
	ArcFM (developed by Schneider Electric) [25]	Google Maps Integration
GE Alstom Alliance [26]	Smallworld	Google Maps Integration Mobile Solutions
Intergraph [27]	Siemens integrated Intergraph GIS	
Oracle [22]	Oracle Spatial	
OSI [23]	OpenGIS	GIS API
NISC	MapWise	

3.5 Current Trends, Strengths, and Weaknesses

Embracing mobile technologies and newer real-time enterprise systems applications are forcing electric utilities to update their GIS systems. From 2010 to 2015, U.S. utilities have each spent (on average) between $110 million and $180 million on GIS upgrades and replacements [60]. Utilities that installed new GIS platforms reported benefits such as reduced losses and liability, increased revenue protection, and reduced reporting requirement of transformer inventory [28]. Integration of GIS platforms with visualization systems such as Google Maps improves the efficiency of assets location and increases outage management responsiveness and customer satisfaction [26].

4.0 Distribution Management System

While a SCADA system allows a utility to monitor and control end-use devices, a full DMS allows a distribution system dispatcher to securely and efficiently monitor and operate their system. A DMS can enable a real-time centralized view of the distribution system and coordinate field operations to achieve a safe and efficient workflow. The DMS stores technical data about distribution substations and feeders, receiving near real-time field measurements through SCADA [30] and other sources such as AMI. Core and foundational to a DMS is an operational 3-phase unbalanced power flow application that is able to take the SCADA (and other) measurements and the power system model to develop a global view of the power flow in the network which can be viewed through an electronic map. In addition, a DMS can have numerous analytic applications that operate on the network model parameters and field measurements. These applications can include, but are not limited to, state estimation, fault location, and switch management.

4.1 Functionality of DMS

Utilities primarily deploy a DMS to increase system observability and controllability, which leads to an increase in the efficiency of operations. An operational DMS can have several analysis packages allowing the utility to process field measurements and data to manage distribution system operations. DMS analysis software and functions can be classified into three main categories [30], [31], [32], [33].

- **Network analysis & control functions –** enables utility operators to carry out network analysis tasks, calculate the state of the distribution network and determine optimal control set-points for various devices.
- **Visualization support functions –** enables GIS-based visualization of the distribution system, replacing conventional paper-based maps and switching orders.
- **Network monitoring and communication functions** - enables communication of several network measurements through SCADA and other sources.

4.1.1 Network Analysis & Control Functions

Network analysis & control functions can be subdivided into four categories: core functions, real-time fault management, real-time operation, and off-line system analysis. These DMS network analysis functions are shown in Figure 4-1.

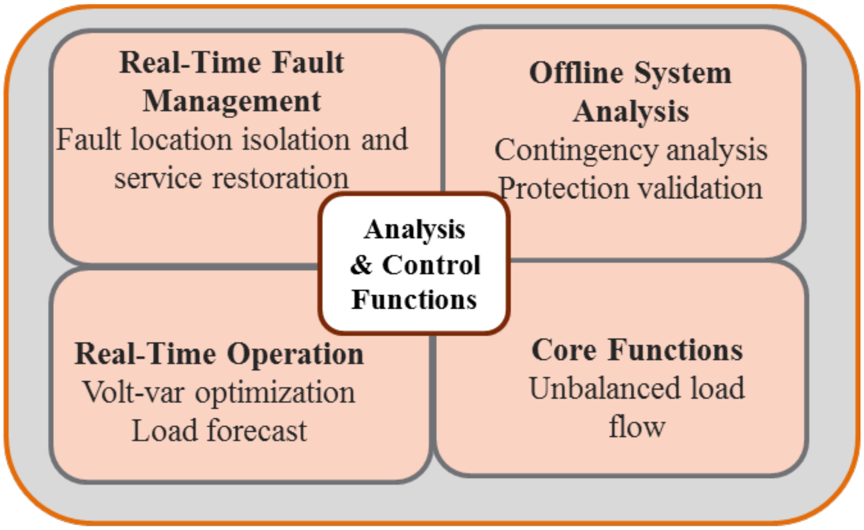


Figure 4-1. Representative DMS Network Analysis Functions

Unbalanced power flow is the core network analysis function for distribution system operations. This function is significantly different than what exists in a transmission system EMS. This difference is due to three factors: a greater level of imbalance at the distribution level, lack of line transposition, and the presence of single- and double-phase laterals. While there are differences between transmission and distribution power flow solvers, their functionality is the same. The swing bus voltage, network model, and end-use load levels are used to determine the voltage magnitude and angle at all points on the system; this is then used to define all real and reactive power flows. These values allow the DMS to have an estimate for values that are not directly measured; observability in distributions systems is traditionally very poor due to limited instrumentation, particularly outside the substation.

Typically, the voltage at the swing bus is determined by substation SCADA measurements from the high or low side of a step-down transformer. The network model is commonly built using an import from the GIS, coupled with asset technical characteristics such as phasing, impedances, and physical orientations. The values for the power consumption at the end-use load can come from a load allocation, historic load profiles, or the AMR/AMI systems. In some DMS power flow solvers, it is possible to use measurements from field devices, such as reclosers and shunt capacitors, to increase the accuracy of the power flow solution. In addition to providing estimates for line flow for a particular case, power flow results from multiple simulations can also be used to calculate the state of the system when switching actions are executed. By conducting multiple power flow simulations, the post-operation line flows and node voltages can be determined before the switching operations are conducted.

Using the power flow to determine the impact of switching operations is based on the assumption that the system topology is known. Errors in the assumed topology can cause incorrect power flow results, which can result in operational violations when switching operations based on these solutions are executed. To minimize the occurrence of topology errors, a DMS can implement a topology processor; while a common EMS function, a topology processor is relatively rare in a DMS. In addition to estimating the topology of the system, a topology processor can provide visual tools such as tracing energy supply paths to a network element. In situations where an unplanned loop or mesh is formed, the topology processor can detect this condition and issue an alarm to warn system operators of the condition [30], [32], [33].

While routine switching operations to facilitate maintenance and the interconnection of new customers are the most common, switching operations related to faults and unplanned outages also regularly occur. Historically, switching operations have been a coordinated effort between the distribution dispatcher and the field crews, with the field crews performing the manual operational of switching. With newer SCADA-enabled switches, the process is still a coordinated operation, but the dispatcher can remotely operate some switches. While these operations are remotely commanded, coordination with field crews is still essential to ensure their physical safety. When faults occur, the dispatcher works with the various field crews, and uses remote controlled switches as appropriate, to locate and isolate faults. This process can be time-consuming and leave end-use customers without service for many hours.

One application that can be run as part of a DMS is fault location isolation and service restoration (FLISR). The level of automation in a FLISR scheme can vary depending on the specific product, and on the operational preferences of the utility. A fully automated FLISR application generates a switching plan to isolate faulted sections, a switching plan to restore service to non-faulted feeder sections, and then executes all switching operations. More commonly, utilities prefer to not automate switching operations that will energize line sections. Instead, they will allow the FLISR scheme to automatically isolate the faulted sections, and then provide recommendations for restoration that must be initiated by the dispatcher.

The determination of the fault location and switching plan is achieved by using data from relays, fault detectors, and any other available data sources. A properly operating FLSIR system automatically prevents equipment overload while rerouting power [30], [34]. Within FLISR it is possible to have a sub-application referred to as fault isolation and service restoration contingency analysis (FISRCA). FISRCA applications execute a FLISR analysis for various possible switching operations, determining if the operation will cause any voltage or thermal limit violations. Automatic feeder reconfiguration (AFR) applications generate switching plans that attempt to achieve a number of goals: minimizing losses, improving system imbalance, and to optimally site distributed resources. AFR is not typically used in response to system faults.

Another operational application that is increasingly being deployed is volt-var optimization (VVO). A VVO system can be deployed as a stand-alone system, but integrating it as part of a DMS increases its effectiveness. VVO typically has two control goals: the reduction of average voltage and reactive power factor correction. These two control goals are typically achieved by controlling the operation of voltage regulators and shunt capacitors. The voltage regulators may be used to reduce the average feeder voltage, which reduces energy consumption, an effect known as conservation voltage reduction (CVR). The shunt capacitors are used to both adjust voltage, and to adjust reactive power. The coordination of these two goals is combined to achieve a number of operational goals that can include peak load reduction, reduction in annual energy consumption, minimizing deviations from average voltage, minimizing control operations, and improved power factor at the feeder head. A reduction of system losses is often cited as a benefit of VVO, but the reduction of losses is small compared to the reduced energy consumption of the end-use load; typically loss reduction is around 1/20th the reduction in energy consumption of the end-use loads [61].

FLISR, AFR, and VVO are examples of operational applications that can run within a DMS, but there are also numerous off-line tools. These functions can include, but are not limited to, protection validation (PRV), planned outage studies, and short-circuit calculations (SCC). PRV applications simulate short-circuit scenarios for each PRV zone, calculate the corresponding fault currents, and identifies unprotected or improperly protected zones. The PRV application compares the fault currents with protective relay settings and the interruption capacity of breakers and reclosers. A planned outage study develops plans to isolate a component, or components, minimizing the number of interrupted end-use customers. SCC simulates short-circuit conditions for a selected distribution location and calculates the resulting fault currents [34], [36]. SCCs are similar to power flow as a basic function that is used by many other applications. Similar to power flow, an SCC can be performed in an off-line planning tool, or in an operational DMS.

The various off-line and on-line analysis functions can ensure secure and efficient operation of a distribution system. To maximize the benefit of the network analysis and control functions, a DMS typically provides visualization as part of the user interface.

4.1.2 Visualization Functions – The Electronic Map

One of the core functions of a DMS is to enable a GIS-based visualization of the system it controls. Given the various planned and unplanned work that is done on a distribution system, a DMS will typically have functions that support continuous modifications to the circuit topology maintained in the GIS, allowing the DMS network model to be continuously updated [2]. As opposed to the GIS, which provides the as-built model, the DMS maintains the as-operated or the as-switched model. Now, if the output of the power flow is superimposed on the as-operated model, we have the beginnings of the electronic map.

4.1.3 Network Monitoring and Communication

As was discussed in Section 2.0, a typical DMS obtains the majority of its field telemetry via a SCADA system. Additionally, SCADA systems carry the command signals that a dispatcher initiates from the DMS. DNP3 (IEEE Standard 1815-2012) is the most common protocol in North America between the distribution control center and remote field devices, even though a large number of legacy protocols are still in place. Field devices support a broad range of protocols, including DNP3, IEC®-60870-5-101/104, and Modbus®. Typically a DMS and SCADA system can be configured to support the specific protocol needs of any utility [35].

4.2 Functionality Diagram

A DMS has the potential to be integrated into a number of other systems, including operational and enterprise systems. Depending on the architecture of a specific DMS deployment, the system with which it is interconnected will vary, with both client and web-based interfaces supported. As with any control system, a DMS has the ability to locally store data and calculation results, and some systems connect to a historian or other archiving application. As discussed previously, depending on the DMS architecture there can be connections to several auxiliary and independent subsystems. A DMS architecture can be viewed as being subdivided into two categories: the individual independent subsystems, and the enterprise-type bus that interconnects them.

Figure 4-2 and Figure 4-3 shows a representative DMS architecture. A DMS can operate as a stand-alone system, or integrate with other internal and/or external systems [25], [34].

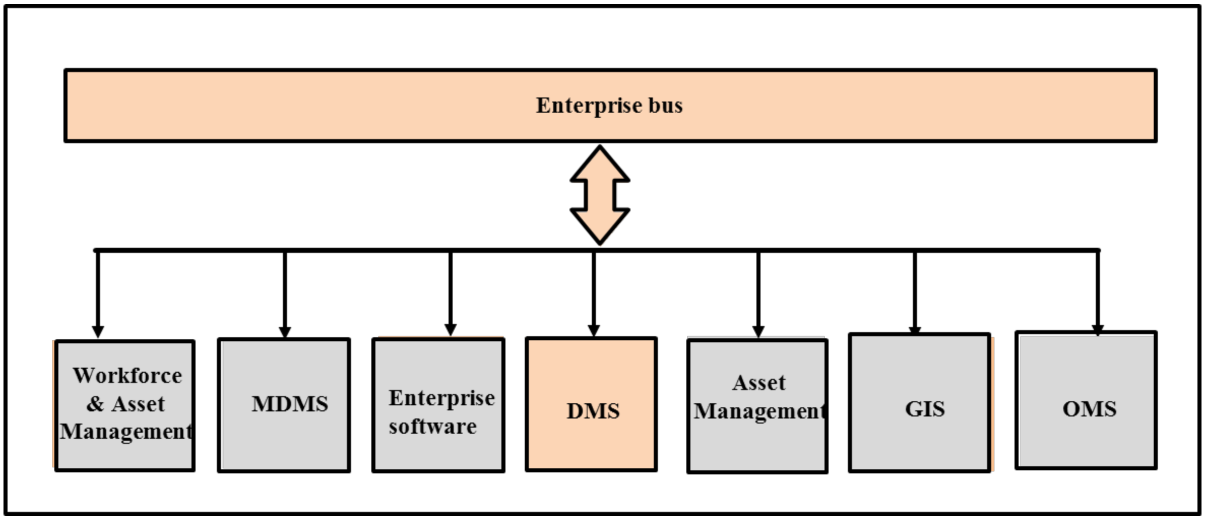


Figure 4-2. Enterprise Architecture for a Distribution Utility with DMS and Other Systems

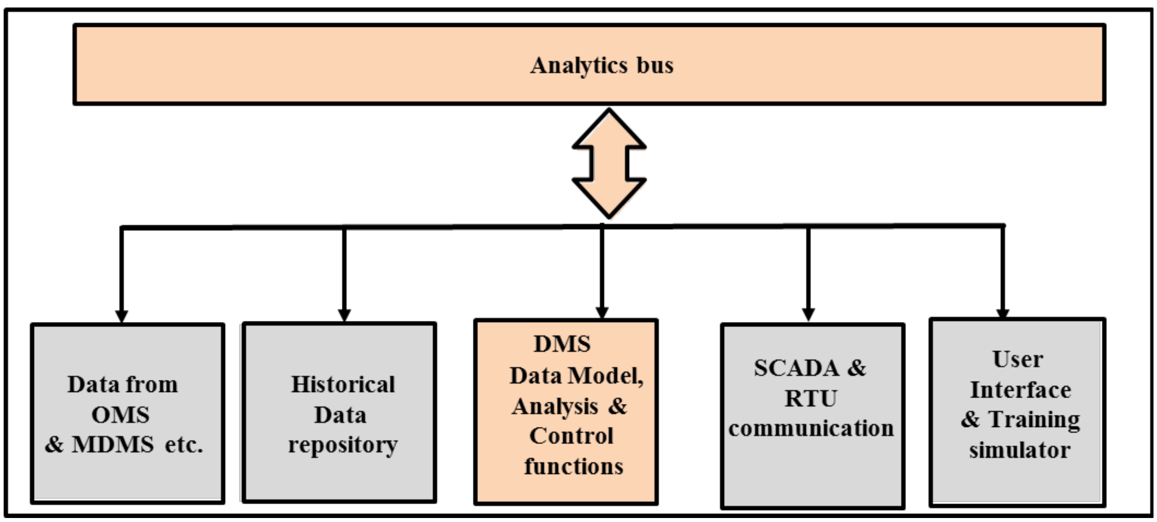


Figure 4-3. DMS Functions Integration with Internal and/or External Systems

4.3 Data Exchange

Within an operational DMS there is the potential for a significant amount of data exchange between numerous systems. A DMS typically has a bidirectional exchange of information with systems such as the OMS, the GIS (generally one-way), the DERMS, and demand response. Unidirectional exchanges are more common with systems such as the AMR, while AMI systems have two-way communication capability as the operator can also communicate with a meter. As an example, an AMI system may send a "last gasp" signal to the OMS when there is a loss of power but can also execute an emergency load shed, using a DMS-commanded AMI "Remote Disconnect" command [12]. In addition to field data, there is the potential for extensive data exchanges within the control center between various systems. As an example, a VVO application within the DMS may be required to develop load profiles for the end-use loads in order to achieve the desired optimization. The DMS could use default load curves, or it could access information from the MDMS, the CIS, and/or the data historian. Using this data, the DMS could create the load profiles for individual loads, perform the state estimation or load estimation, and analyze the load voltages profiles for VVO [12]. The interaction between the DMS and these systems occurs within the control center.

This is a single specific example of one application, VVO, but it highlights the type of data exchanges that involve the DMS and can occur within the control center. The data exchanges that were described for the VVO were fully automated and did not directly involve a system dispatcher. A basic example of inter-control center data exchanges that involve system dispatchers is the exchange between the DMS and the GIS, where the GIS information is necessary for the DMS to provide an accurate visualization of the distribution systems. A DMS can include HMI features, which enables operators to visualize the network geographically and schematically. The primary HMI is typically located at the control center, but it is becoming more common to see the same information displayed at multiple locations, including tablets that field crews may use. Alarm functionality is also another important DMS function, which can have inputs from multiple locations [30]. A representative DMS control center data interactions & exchanges are shown in Figure 4-4.

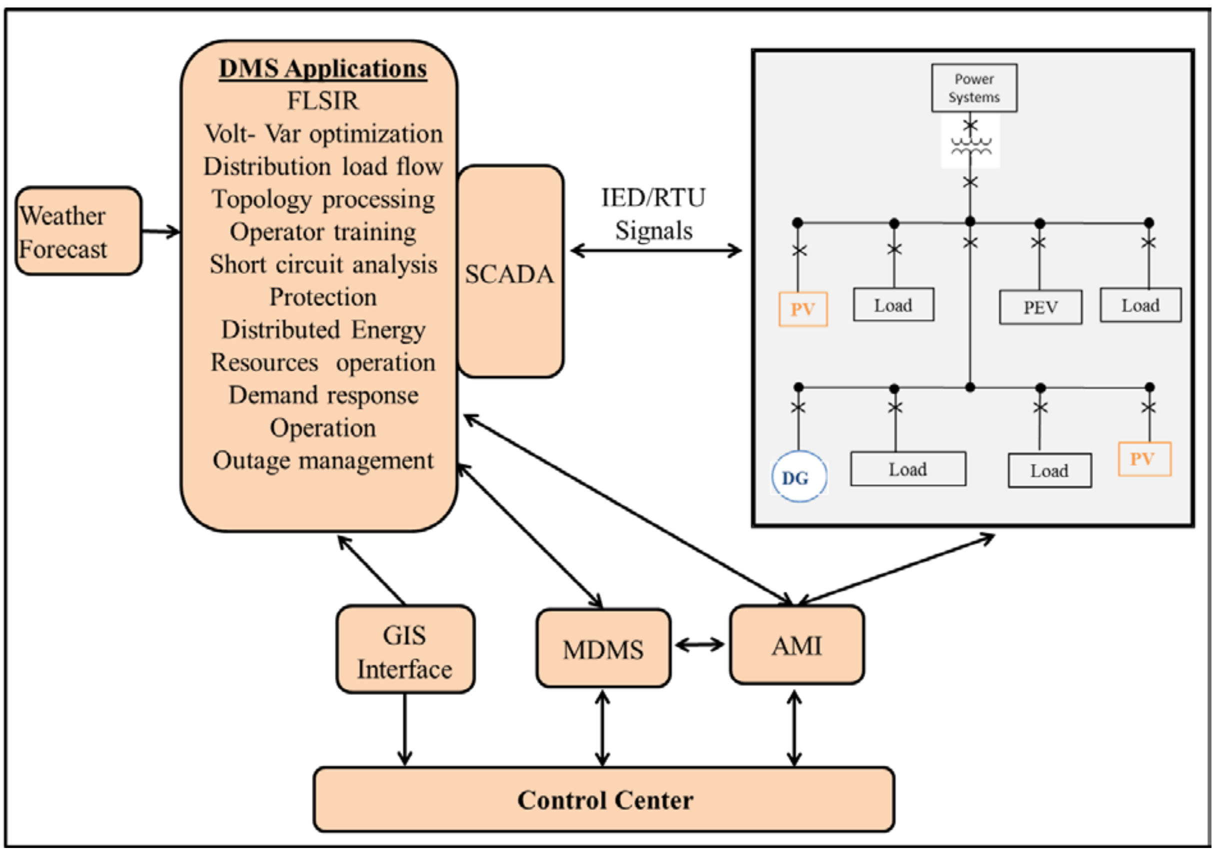


Figure 4-4. Representative DMS Control Center Data Interactions and Exchanges

4.4 Vendor Details

Table 4-1 presents a selection of DMS vendors and their products. While this is not a comprehensive list, it is a representative cross section of DMS products offered by vendors. The table identifies the name of the vendor's product, and what specific applications are available through that vendor's DMS. The applications listed are those that are most commonly associated with the DMS and include, but are not limited to: FLISR, SCC, power flow, protection validations, automatic feeder reconfigurations, planned outage study (POS), and VVO.

While the majority of DMS deployments start with a commercial platform, each deployment requires extensive modifications to meet the requirements of the individual utility; there is no single "turnkey" solution that can be universally deployed. Vendors typically provide base components for their systems, with additional components added as requested. This approach results in DMS implementations that have different functionalities, which must be treated as separate projects, each with unique integration requirements [3]. Vendors provide core features, such as unbalanced power flow and connectivity analysis, with the base product. Extra functionalities such as FLISR and VVO are driven by utility based operational needs, business case analysis, and legacy systems in operation.

From Table 4-1 it can be seen that vendors offering DMS products include, but are not limited to, the ABB Group, Siemens AG, and Schneider Electric [30], [31], [32], [33]. Most of the DMS vendors offer a common set of applications such as unbalanced power flow, FLISR, short-circuit analysis, and PRV. While each of the vendor products contains similar core capabilities, the specific implementation and capabilities of each vary. To determine the differences between each product it is necessary to consult the vendor-supplied documents; references are provided for each product listed. Specific product names are not listed due to their frequent changes.

Table 4-1. Partial List of DMS Vendors

Vendors	FLISR	SCC, Power Flow, PRV	AFR	VVO
ABB [30]	Yes	Yes	Yes	Yes
GE Alstom Alliance [31]	Yes	Yes	Yes	Yes
Schneider Electric [32]	Yes	Yes	Yes	Yes
Siemens [33]	Yes	Yes	Yes	Yes
Survalent [37]	Yes	Yes	Yes	Yes
Open Systems International, Inc. (OSI) [38]	Yes	Yes	Yes	Yes
Oracle [39]	Yes	Yes	Yes	Yes

4.5 Current Trends, Strengths and Weaknesses

Typically, a DMS platform is implemented in a modular fashion to avoid the high costs of a single monolithic deployment [4], [21] though large monolithic deployments do sometimes occur. A common scenario would be for a utility to deploy an OMS that is integrated into their MDMS. Later a DMS would be deployed and integrated with the OMS. A possible future DERMS deployment would tie into the DMS. The exact path of the DMS deployment (and the systems that it is connected to) will depend on the needs of the utility, the problems it is trying to solve, existence of legacy systems, and the vendor selected.

Currently, we believe less than ten percent of the distribution utilities in the United States operate a dedicated and integrated DMS. The majority of other utilities manage collections of disparate systems that have been combined over time in an ad hoc manner to view and control their electrical infrastructure. The capabilities and architecture of an ad hoc DMS will depend on the systems that the utility began the process with. For example, an OMS-based deployment path may have more visualization functions than a SCADA-based deployment path. In the end, each path can lead to a DMS, but they will be very different. It is the numerous combinations of paths that utilities have followed in building their DMSs that creates an industry without a universally agreed upon definition of what is, and what is not a DMS. Even utilities with a dedicated DMS often continue to operate collections of disparate systems that are connected to the DMS to varying degrees. These systems include, but are not limited to, SCADA, OMS, GIS, AMI, and MDMS [4], [21].

The high-priority major applications utilities are commonly implementing or planning to implement in their DMSs are FLISR, VVO, and switching management [40]. While there are many other applications of interest, these three represent the largest driving force for DMS deployment. Some utilities are expressing interests in the implementation of training simulators to help dispatchers learn how to work in environments with a higher degree of integration. This enables utilities to train dispatchers for operations that are far more complex than what has traditionally been experienced at the distribution level.

One of the most common trends is a utility showing an interest in leveraging their AMI measurements to improve observability of their system. Schemes have been proposed that use both direct observation of measurements, as well as state estimation based methods. Another significant area of interest for DMS integration is to help with the planning to address the proliferation of DERs. Many utilities plan to implement direct data exchange between the DMS and the DER while others use a stand-alone DERMS [12], [40]. DMS integration with DERMS, SCADA, OMS, GIS, AMI, and MDMS faces several challenges and utilities have expressed that integration between these systems is difficult. The integration of data and information between these different systems can create data issues; many utilities have experienced significant difficulties in managing this integration [4].

5.0 Automated Meter Reading/Automatic Metering Infrastructure

The first automated meter reading (AMR) systems were deployed during the early 1990s, and these provided the first fully automated method to collect end-use customer energy consumption data. The primary function of AMR is to provide revenue-grade meter reading of end-use customer energy consumption. Advanced metering infrastructure (AMI) was not implemented on a large scale until the mid-2000s, and these systems had significantly more capabilities than AMR. Meter data management systems (MDMS) have evolved to support the data generated by AMR and AMI systems.

5.1 Functionality of AMR/AMI

The primary function of AMR is to provide revenue-grade energy consumption data for each end-use customer. There is a significant difference between the operational capabilities of AMI and AMR [41]. Typically, AMR only involves data metering and one-way communication functions back to the utility, while AMI is enabled by two-way communication and remote controllability, if supported by the deployed smart meters. For an AMI system, a two-way communication infrastructure is necessary, and it can provide additional functions such as transmitting pricing information, demand response signals, and outage information.

An MDMS provides data storage and data management software for the collected meter data [42]. The primary function of an MDMS is to take the information from AMR/AMI and process it for customer billing systems. While an MDMS can implement numerous functions, billing is its primary objective. MDMS can share data with several other systems such as asset maintenance systems, customer relationship management, trading systems, DMSs, GISs, and OMSs.

5.2 Functionality Diagram

The combination of AMR/AMI and an MDMS defines the core components of end-use energy consumption measurement for a utility that no longer relies on physical meter reading. Additionally, two-way communication features of an AMI and an MDMS allow for the possibility of end-use loads to be active participants in power system operations. While the combination of AMI and MDMS provides numerous new operational possibilities, they also give rise to a significant volume of data that must be transferred, processed, and archived. An MDMS is typically capable of handling the large volume of data that is associated with AMI. The ability to handle the data includes not only the technical requirements of bandwidth and latency, but also privacy concerns requiring a specifically-designed database architecture to address those concerns.

Figure 5-1 shows a representative architecture of an AMI and an MDMS. The AMI measures active energy consumption data, typically as a 5-minute or 15-minute average, and transmits it to the MDMS. The communications infrastructure supporting this transmission will vary between utilities, but it is not uncommon for it to include a wireless radio between the smart meter and a data aggregation point, where it connects to a fiber optic backhaul running to the utility back-office. The backhaul line can be either a utility-owned or a leased connection. Once the data is transmitted to the utility, the MDMS has validation and estimation functions to ensure the veracity of data. The MDMS then uses data processing features for billing calculation based on the individual end-use energy consumption, and customer rates. All transactions are then processed through a workflow management process.

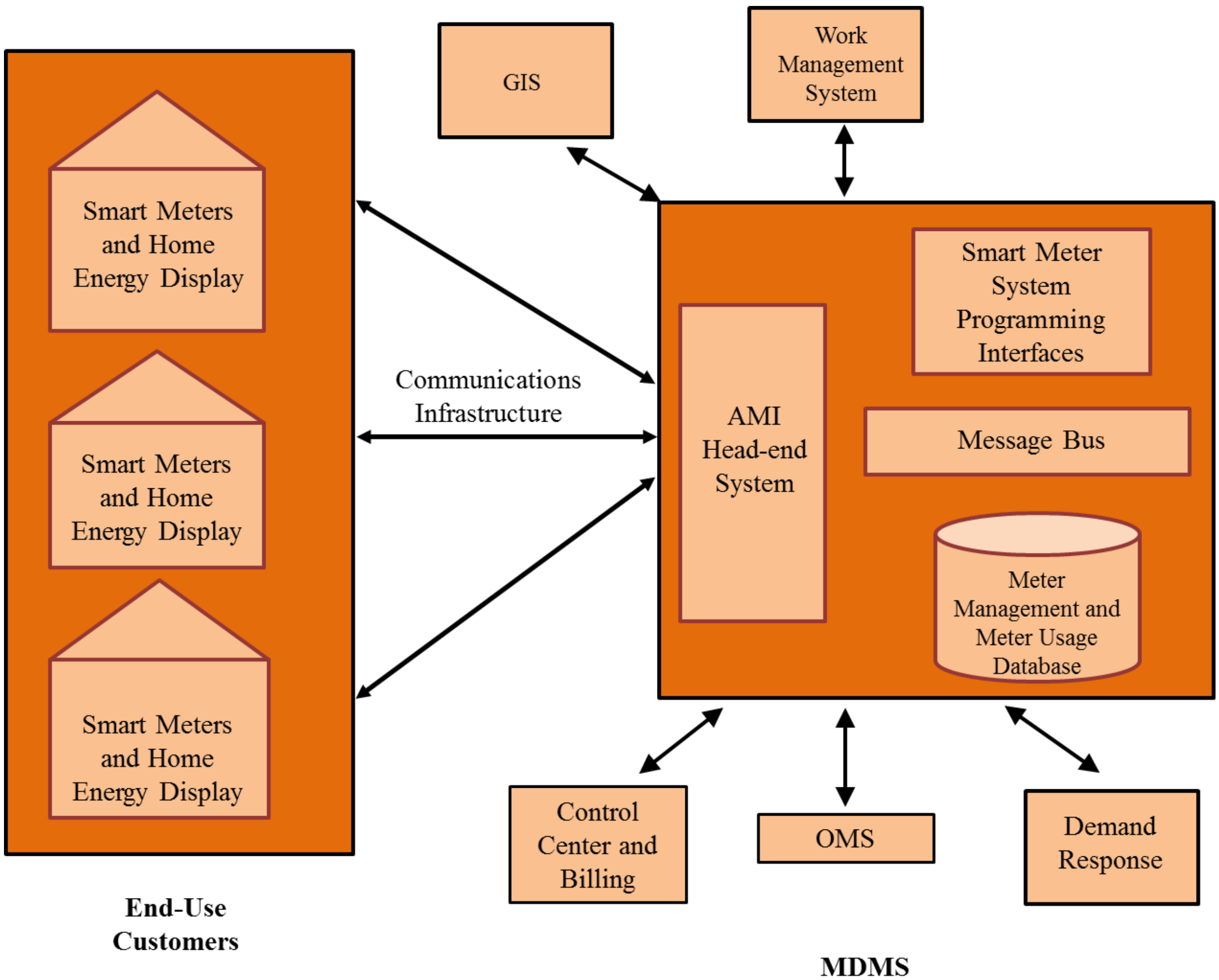


Figure 5-1. Representative AMI and MDMD Architecture

5.3 Data Exchange

Data collected from the AMR/AMI, and processed by the MDMS, can be used by other systems to improve distribution system operation. For example, an AMI system, either directly or through an MDMS, can provide a "last gasp" signal to an OMS as the meter goes off line due to an outage in the area. This message allows the OMS to more quickly identify and define the scope of the outage and hence enable faster recovery. The operator can also "ping" a meter (or a group of meters) to confirm their "power-on or off" status.

In addition to the OMS, integration between an MDMS and other systems can be performed over connections such as an Enterprise Service Bus (ESB). A representative scheme for control center data interactions and exchanges is shown in Figure 5-2. In Figure 5-2, the connections between the MDMD and other subsystems are shown; connections to DMS and OMS are not shown. It is also not uncommon to use an industry standard protocol such as ICCP, from IEC 60870-6, to transfer data between the OMS and the DMS system.

AMI smart meters exchange data with an MDMS and receive operational commands from an operation center. Communication is an essential part of AMI. AMI communication infrastructure handles a very high volume of data and must have a very high reliability. Privacy and security of load energy consumption data is a critical attribute of data collected by an AMI. The data collection and communication has to be authenticated from a billing point of view and communication infrastructure should support future expansion. There are various communication architectures possible. The smart grid communication literature also discusses various technologies such as power line carrier communication (PLCC), broadband over power lines (BPL), fiber optics, cellular, WiMAX, Bluetooth, ZigBee, etc.[43].

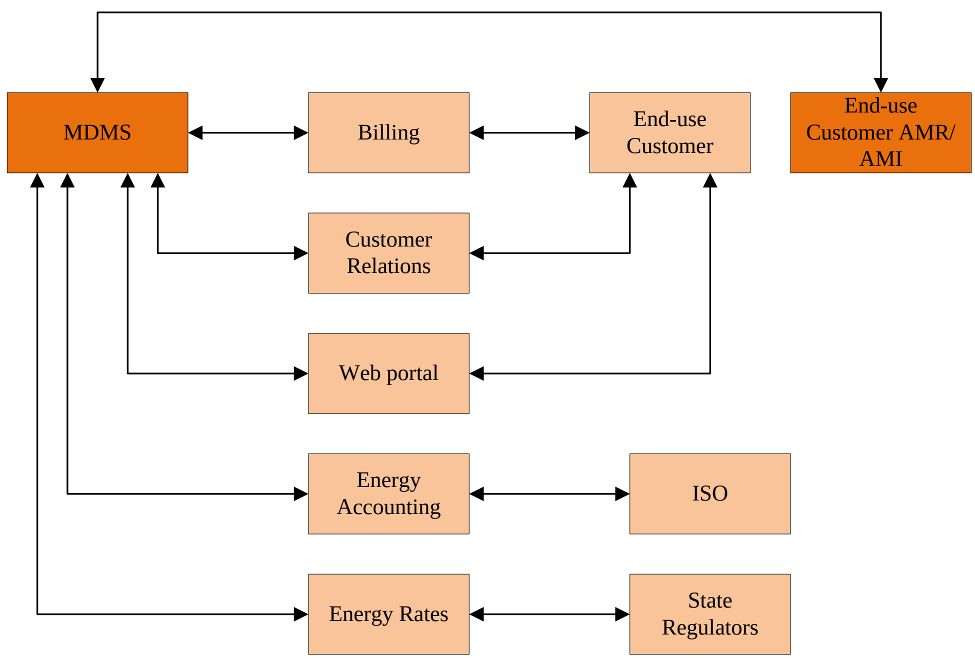


Figure 5-2. Representative MDMS Data Exchange

5.4 Vendor Details

Table 5-1 presents a selection of AMI and MDMS vendors and their products. While this is not a comprehensive list, it is a representative cross section of AMI and MDMS products offered by vendors. Similar to the DMS functions in Table 4-1, each of the MDMS vendor products contains similar core functions, but the specific implementations and capabilities of each vary. To determine the differences between each product it is necessary to consult the vendor-supplied documents; references are provided for each product listed. These vendors can be classified into the following three major categories:

1. Vendors who have business lines that traditionally have focused on a broad range of hardware and software for the electric utility industry. These vendors include, but are not limited to, ABB, GE, Siemens, and Schneider.
2. Vendors who have electric utility business lines that traditionally have focused on meter hardware [44], [42], [45], [46]. Itron is an example of such a vendor.

3. Vendors who have electric utility business lines that traditionally have focused on enterprise software, including IBM and Oracle as examples.

Table 5-1. Partial List of AMI and MDMS Vendors [44], [42], [45], [46]

Vendors	AMI Hardware	MDMS	Enterprise Application Interface	Outage Detection and Interactive Voice Response, etc.
ABB	Yes	Yes	Yes	Yes
GE	Yes	Yes	Yes	Yes
IBM	Yes	Yes	Yes	Yes
Itron	Yes	Yes	Yes	Yes
Oracle	Yes	Yes	Yes	Yes
Schneider Electric	Yes	Yes	Yes	Yes
Siemens	Yes	Yes	Yes	Yes
Landis & Gyr	Yes	Yes	Yes	Yes
Aclara	Yes	Yes	Yes	Yes
Sensus	Yes	Yes	Yes	Yes
NISC	Yes	Yes	Yes	Yes

5.5 Current Trends, Strengths, and Weaknesses

As discussed in the previous section, the features available in an MDMS vary between vendors and deployments. These features can include, but are not limited to, billing, interfacing with GISs, interfacing with OMSs, and interactive voice response (IVR) services (see section 6.2).

Some recent trends in MDMS deployments include connections to OMSs, support for demand response schemes, and data analysis packages. There is also an increasing interest in extending back-office data into the field to provide field crews the ability to view work orders and work flows.

A key strength of AMI over AMR is the support for two-way communication. This gives many advantages to AMI as compared to conventional AMR. Table 5-2 compares the various aspects of AMR and AMI.

Table 5-2. AMR and AMI Strength and Weaknesses

System Element/Feature	AMR	AMI
Meters	Solid state	Solid state
Data Collection	Drive- by	Remote via communications links
Data Recording	Energy usage	Time-based (usage each hour or more often, usually 15 min. or less). Data gathered also includes energy consumed, voltage, power quality, and others.
Utility Support	None	Remote connect/disconnect
Applications Support	Customer billing	Pricing options, Customer options, Utility operations, Emergency demand response
Software Interfaces	Billing and CIS	Billing, CIS, OMS, Demand response
Additional Devices Enabled	None	Smart thermostats In-home displays Appliance controllers
Pricing	Total consumption only	Total consumption, Time-of-use, Critical peak pricing, Real-time pricing
Demand Response	None	Load control, Demand bidding, Demand reserves ,Critical peak rebates
Customer Feedback	Monthly bill	Monthly bill, Monthly detailed report, Web display, In-home display
Outages	Manual call	Last Gasp and meter pings for Power-on confirmation
Distribution Operation Support	Nil	Real-time operation support

6.0 Outage Management Systems

An outage management system (OMS) is deployed to increase the ability of a utility to manage outages to their distribution customers. Depending on the specific implementation, the OMS can be used to manage unintentional outages as well as planned outages. In addition to managing data from field devices, some OMSs also have the potential to manage the workflow and the coordination of field crews.

6.1 Functionality of Outage Management Systems

An OMS is a suite of applications used by distribution dispatchers to manage planned and unplanned outages. Planned outages occur for maintenance and the interconnection of new customers, while unplanned outages can occur due to a variety of reasons including vegetation, weather, and storms. An OMS's primary role is to track and manage unplanned outages at a utility's distribution system. In addition, an OMS is also responsible for identifying customers or areas affected by an outage, prioritizing the power restoration efforts and performing prediction analysis of the restoration times [3].

Typical OMS functionalities include, but are not limited to

- **Track and manage outages** – The fundamental OMS functionality is to track every switch position whether on or off. In addition to using this information to understand the location of the outage, it also helps with maintaining accurate outage counts necessary for outage reporting.
- **Call and event management** – Interface with the customer service system, which is responsible for recording trouble-reporting calls and smart meter events.
- **Incident and crew management** – responsible for accurate incident location estimation and for efficient crew dispatching during unplanned outages or planned maintenance activities
- **Customer information system** – responsible for storing and sharing customer outage data with other systems that the OMS is connected with [12].

In some utilities, the legacy OMS is an independent stand-alone system that is not connected to the DMS or SCADA.

6.2 Functionality Diagram

The earliest implementations of OMSs were little more than an operator who would take phone calls from customers reporting outages. As computerized systems increased in capability it was possible for customers to use touch-tone phones to enter information in response to a series of questions, and the information would be recorded in an OMS. Interactive voice recognition (IVR) technologies allowed for more information to be collected than via touch-tone systems. Both touch-tone and IVR capabilities increased the OMS capacity in terms of the number of outage calls that could be managed. Combining the recorded outage call info with the customer billing data from the CIS provides the ability to link individual customers with a specific secondary service transformer. To accurately dispatch field crews to a specific outage location, an OMS uses a logical connectivity model of the distribution system. Typically, a GIS is the source of network connectivity model that is imported into OMS; having an accurate geospatial representation of the system is essential for more efficient outage restoration [2].

Figure 6-1 shows a representative architecture of an OMS. In this architecture, the OMS receives outage inputs from the AMR/AMI systems and from customer calls. The geospatial information used by the OMS is imported from the GIS and updated with any topology changes that are initiated from the DMS [21].

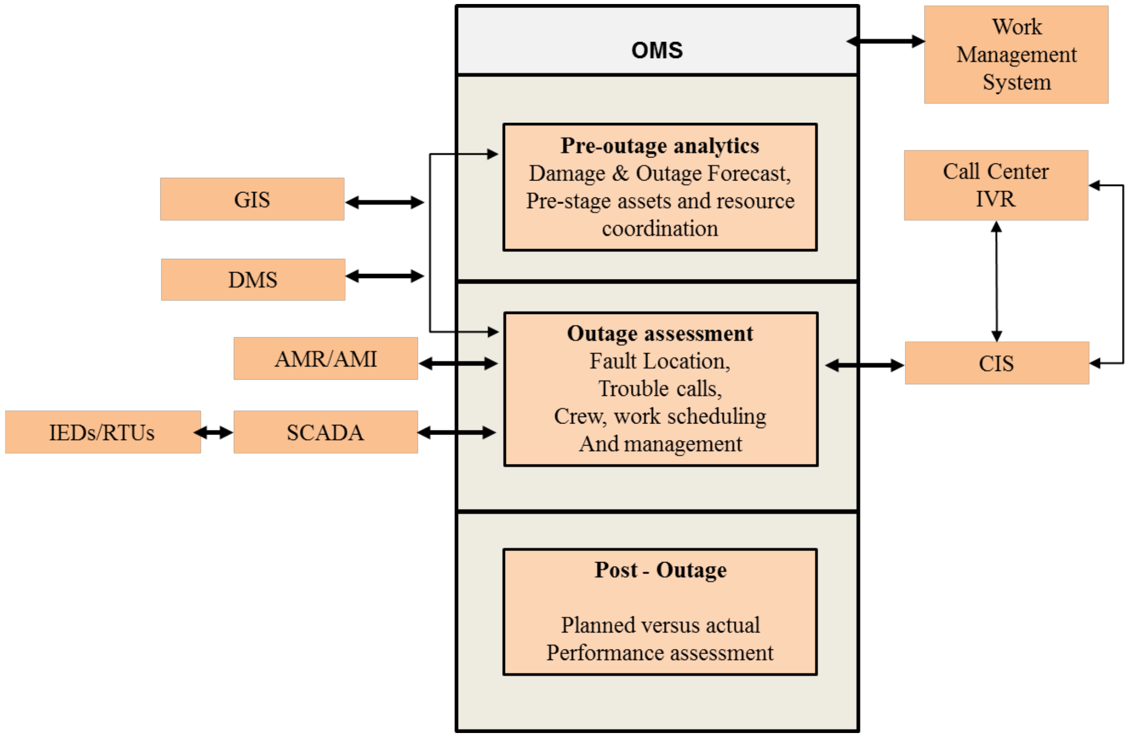


Figure 6-1. Representative OMS Architecture

6.3 Data Exchange

Typically, the OMS is developed independently of DMS and SCADA systems [12], but the integration of the OMS with the DMS and SCADA is an increasing trend. The benefits of integrating an OMS with other systems includes, but is not limited to, shared network model maintenance effort, improved operational efficiency, and increased data availability.

The effective integration of an OMS with a DMS requires two-way communications between the two systems. The report "Guideline for Implementing Advanced Distribution Management Systems" [12] identifies some of the main data exchanges necessary when integrating the OMS and the DMS; a selection of these is shown in Table 6-1. It should be noted that while the referenced guideline states that information should flow in both directions between DMS and OMS, in practice utilities usually prefer that information does not automatically update from the OMS to the DMS. In other words, data flows from OMS to DMS involve human supervision.

Table 6-1. Data Communication between DMS and OMS

OMS		DMS
Update grid topology from operator manual operation (and implemented in the field by field crew)	←	Switch operations from operators and automatic controls
Fuse or local-automatic switch status estimation, based on trouble calls	→	Update statuses of the identified fuse and local-automatic switch
Predict customer outage based on DMS planning	←	FLISR and other planned switch operation schedules
Make switch orders and estimate repair time for DMS operation	→	Execute the automatic switch order from OMS

There are numerous benefits of integrating a DMS with an OMS, but only if the data from the DMS provides actionable information for the distribution system dispatcher and/or automated systems. For example, during Superstorm Sandy in 2012, the utilities reported that their OMSs indicated system-wide outages, without being able to pinpoint the source of the outage. As the New York storm progressed, approximately 264 transmission assets were removed from service, in addition to the numerous distribution assets that were damaged, resulting in approximately 8.35 million electric customer outages [28]. During this event, the fact that the entire distribution system was without service was not useful to distribution system dispatchers, because the OMS was typically not able to indicate whether the outage was due to a transmission asset outage, a distribution asset outage, or a combination of the two. The OMSs were completely overwhelmed.

The accuracy of network connectivity information is an important factor that influences the correct operation of an OMS. The AMR/AMI data can be used by an OMS to validate that the customer locations in the GIS are accurately linked in CIS. At the same time, AMI-OMS integration has the potential to serve as a restoration verification mechanism, [19]. Similar to integration with the AMR/AMI, an OMS can be integrated with SCADA to automatically confirm the occurrence of outages or restorations using measurements from field devices such as voltage regulators, shunt capacitors, reclosers, and remote switches [36].

6.4 Vendor Details

Similar too many of the other operational tools used by distribution utilities, there is no single definition of what an OMS is or its core functionality. Table 6-2 presents a selection of OMS vendors and their products. While this is not a comprehensive list, it is a representative cross section of OMS products offered by vendors. Similar to the DMS functions in Table 4-1, each of these OMS vendor products contains similar core functions, but the specific implementations and capabilities of each vary. To determine the differences between each product it is necessary to consult the vendor-supplied documents; references are provided for each product. Table 6-2 also summarizes the various implementations and their functionalities by vendors [36], [38], [50], [62], [63]. Many vendors provide OMS as a stand-alone independent system, leaving it to the utility to decide the path for integrating with other systems.

Table 6-2. Partial List of OMS Vendors

Vendors	Outage Analysis and Reports	Optimized Crew Dispatch	Stand-Alone System	Reliability Indices
ABB	Yes	Yes	Yes	Yes
GE	Yes	Yes	Yes	Yes
Milsoft	Yes	Yes	Yes	Yes
OSI	Yes	Yes	Yes	Yes
Schneider Electric	Yes	Yes	Yes	Yes
Siemens	Yes	Yes	Yes	Yes
Intergraph	Yes	Yes	Yes	Yes

6.5 Current Trends, Strengths and Weakness

Because of the increasing complexity of distribution system operations, and the increasing expectations of end-use customers, there is a trend away from legacy paper-based outage tracking systems. While the majority of distribution utilities do not employ a full OMS, the industry trend is toward more automated systems. Additionally, future trends will see increased integration between OMS and other systems such as the AMR/AMI, the DMS, and SCADA.

There are two significant limitations of OMSs. First, during extreme weather events, when large portions of a utility's distribution system are out of service, the value of an OMS is greatly decreased [52]. Second, the typical OMS is heavily reliant on external communication links, which can also become damaged during an extreme weather event [28].

7.0 Distributed Energy Resource Management System

Distribution systems are facing increasing economic and technical challenges due to the proliferation of distributed energy resources (DERs). Distributed energy resource management systems (DERMS) have recently emerged as an appealing system to manage various DERs such as electric vehicles (EVs), various distributed generation (DG) systems, demand response (DR), and battery storage systems [21]. These systems can be either stand-alone or integrated into other systems such as a DMS.

7.1 Functionality of DERMS

DERMS functionality varies significantly between each vendor’s product due to the wide range of roles that DERs can play in an operational environment, and the varying relationships they have with the local utility. Because of the potentially broad functionality provided by DERMSs, the architecture is typically customized and highly dependent on the specific functionality provided by the product. There can be several distribution system and DER objectives which DERMS can manage [29], [12], [53], [54], [55]. These can include, but are not limited to

- Management of distributed energy storage
- Management of distributed electric vehicles
- Management of distributed solar
- Management and dispatch of distributed (non-renewable) generation
- Management of DR including interaction with building energy management systems (BEMS) and transmission-level load shedding.

7.2 Functionality Diagram

DERMS can have the ability to communication with several other systems such as the DMS, the MDMS, the GIS, and/or the CIS. DERMS can communicate information regarding the present state of a given DER’s operation with a DMS (or just a SCADA) and can receive control input from the DMS. Figure 7-1 shows a representative architecture of a DERMS.

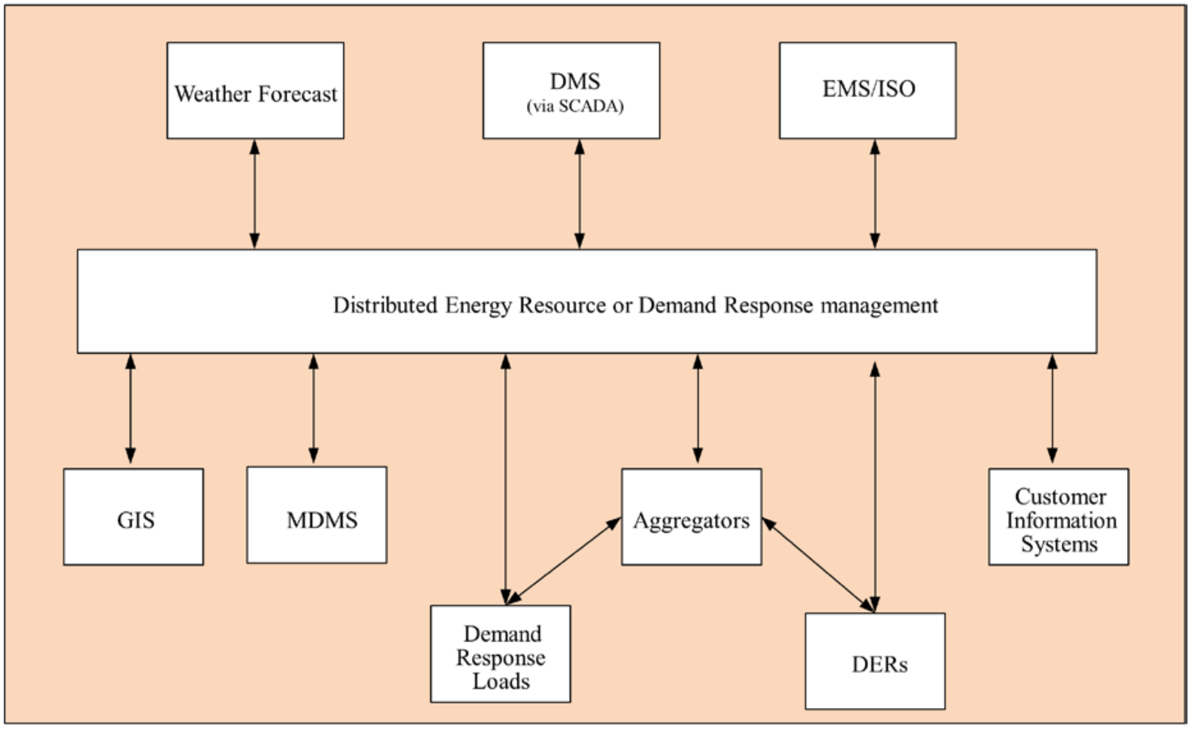


Figure 7-1. Representative DERMS Architecture

One of the applications of a DERMS in the presence of electrical markets is demonstrated in Figure 7-2. Electrical markets and DER trading functions can communicate contractual information with a DMS and a DERMS. Further, a DERMS, through SCADA and AMI, may have communication with home area networks (HANs), building energy management systems (BEMSs) and DER aggregators. Thus, a DERMS can act as an interface platform between load, DERs, and electricity markets.

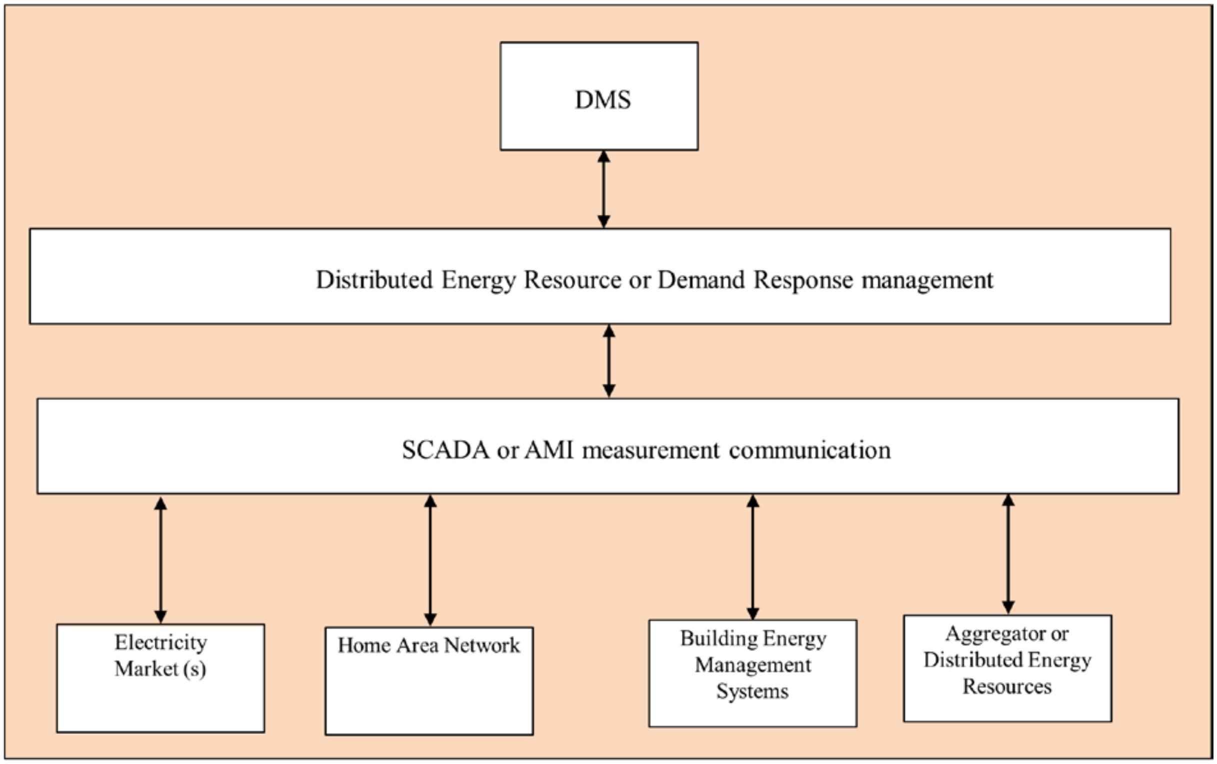


Figure 7-2. DERMS as an Interface Platform DERs and DMS

7.3 Data Exchange

The DERMS data exchange depends on the architecture, functionality, and type of DERs deployed in a utility's service territory. A further complexity to determining the architecture of a DERMS is the ownership structure of the DERs. While utilities may own and operate some DG and energy storage, the majority of DERs such as residential PV are not likely to be owned or operated by the utility. As a result, the exact architecture of the DERMS will vary. DERMS, when integrated with the DMS, can communicate DG active and reactive power injection values at the DER's point of common coupling (PCC). DERMSs can also communicate with third party aggregators instead of individual DERs, and this greatly reduces the number of data connections. Based on the business case and objectives of a utility, data exchange requirements will vary.

7.4 Vendor Details

DERMS vendors include, but are not limited to, ABB, GE, OATI, Oracle, Schneider, OSI, Aclara, Comverge, Enernoc, Siemens, Smarter Grid Solutions, and Spirae. Some of the DERMS have more DR focus while others have more renewable energy management focus [29], [12], [53], [54], [55].

7.5 Current Trends, Strengths, and Weaknesses

Monitoring, control, and dispatch of DERs is the core function of DERMSs. In the case of renewable energy, a DERMS's weather forecasting functionality is central to the DERMS. Some advanced functions are market interfaces, DR management, and microgrid monitoring and control [29], [54]. DERMSs can also have an architecture that manages DER assets as a portfolio of resources, operating as grid-connected and/or autonomous microgrids.

8.0 Advanced Distribution Management Systems

Many of the previous sections have discussed how the various common distribution management systems (each performing a specific function) have the potential to be integrated with each other. In an ADMS all systems are integrated through a common “data bus” that enables the seamless sharing of models, measurements, database values, and control signals. Typically, an ADMS has a shared common network model and integrated visualization between OMS, DMS, SCADA, and other advanced applications [48], [21]. The development of the integrated ADMS environment is ideally vendor agnostic so that utilities can adopt ADMS without needing to commit to a single vendor.

An ADMS platform provides operational and analytical tools that enable the electric utility’s distribution dispatchers to efficiently manage the distribution assets, quickly process near real-time data and get ready for the new environment of greater levels of DER penetration and/or transactive loads. What previously were siloed utility functions, in an ADMS platform become necessary components of an environment within which applications are run over well-defined interfaces, enabling functionality, interoperability, and well-defined forms of interaction [27]. The adoption of ADMS platforms, and the overall concept of an integrated operating environment, is increasing and is expected to include not only large utilities, but also mid-size utilities [56]. Navigant Research predicts a global revenue growth in ADMSs from $681.1 million in 2015 to $3.3 billion in 2024 [57].

An effective ADMS platform “has to balance the constraints of the past, the needs of today, and the uncertain challenges of the future, if it’s going to succeed in the marketplace” [27]. Studying the current market, ADMS is most commonly deployed to address a limited number of issues. Currently, utilities deploy ADMS for applications that include, but are not limited to FLISR, VVC/VVO, integration of DERSs, DR programs, planned and unplanned switching management, and intelligent alarm processing [58], [4].

8.1 Functionality Diagram

Architecturally, an ADMS platform is designed to follow a service-oriented approach, supporting several systems working in parallel within an integrated environment. There are the following types of subsystems:

- Real-time systems processing operational data (D-SCADA, RTUs, IEDs)
- Near real-time systems performing core and related analysis (electronic map, paperless switching, 3-phase unbalanced power flow)
- Advanced applications that perform assessments for the dispatcher (State Estimator, Contingency analysis, FLISR, VVO, forecasting, and other study apps)
- Integrating with off-line systems processing low-speed data (CIS, GIS, AMI/ARM, etc.).

A representation of all the integrated systems into an ADMS platform is shown in Figure 8-1. It also presents the functional layers of each system integrated into the ADMS platform. The architecture shown is only one of many examples, and demonstrates the complexity of system integration.

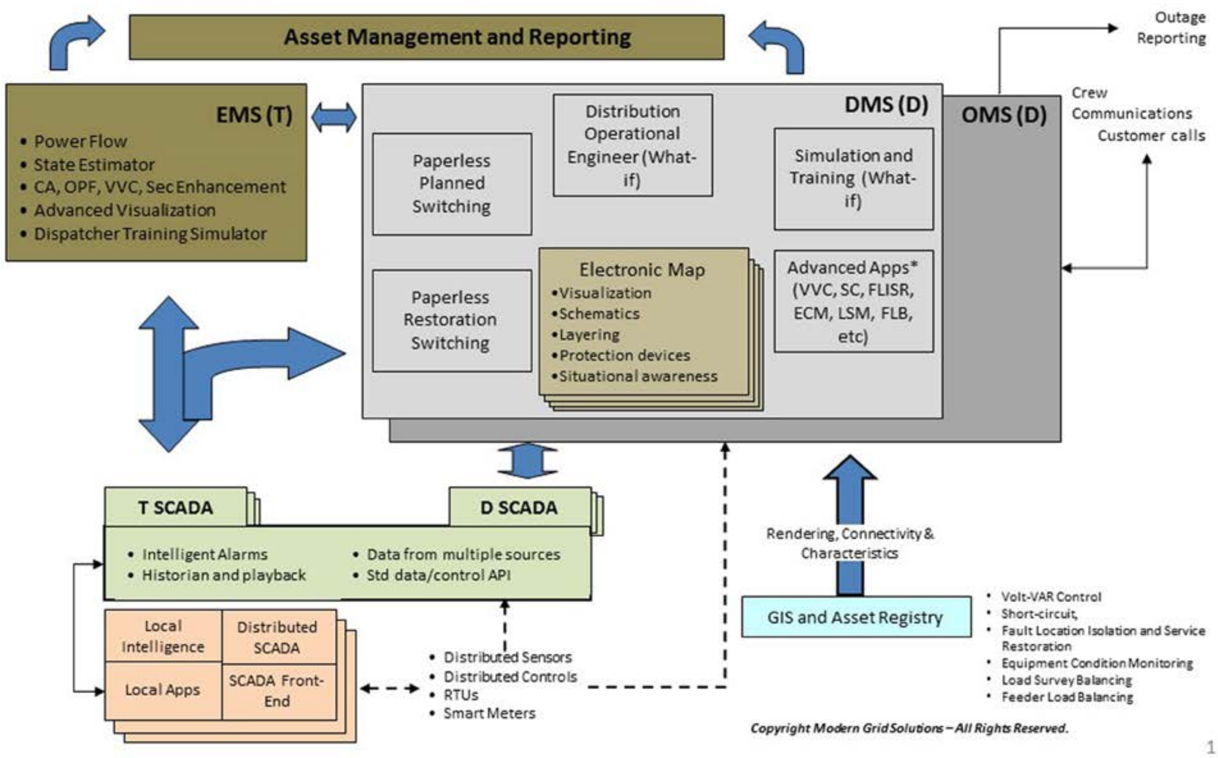


Figure 8-1. Conceptual ADMS Architecture (figure provided by Modern Grid Solutions)

8.2 Data Exchange

The foundation of ADMS is the integrated environment and the seamless transition of data and control signals [4]. It is important for utilities adopting ADMS to realize that data management drives change management and there is a continuous need to adapt to meet new data requirements. Understanding that the past experiences with planning tools and DMS implementations are not fully transferable into the ADMS deployments is a key factor in successfully moving forward. For instance, an OMS is implemented based on a connectivity model of the as-built system, while an ADMS uses an electrical model derived from accurate network information from the currently as-operating system. “The ADMS relies on accurate distribution network data available on a real-time basis besides the as-built and the as-operated connectivity details” [12]. This means that for an ADMS, the power-flow solution of the current as-operating state must solve consistently.

From the early planning phase of an ADMS installation, requirements for data and data-readiness checks should be performed, allowing utilities to identify the specific advanced applications to be used and quantify the existing data deficiencies. Since ADMS is an integration of multiple system models, creating an overview of the required data types for its deployment [21] helps utilities plan the new technologies integration. A brief list of possible data types is presented below:

- **Infrastructure data**: equipment type, location, ID, and rating
- **Customer data**: personally identifiable information of customers, households, and meters

- **Customer-to-network link**: information available through transformer-customer mapping and customer load model (if AMI is not implemented)
- **Network topology**: connectivity, phasing, device as-built state information
- **Metadata**: element naming, data ranges and limits, analysis parameters
- **Engineering data**: impedances, connections, settings, sensing nodes
- **Meter data management**: data feed to DMS from smart meters.

In an ADMS implementation, there are well-known sources of inaccuracy (i.e., network model from the GIS, SCADA measurements from the field, customer premises uncorrelated with network link data, etc.) that should be accounted for. The experiences of Oklahoma Gas & Electric Energy Company provide just one example. They examined what they considered to be the most important ADMS applications (FLISR and VVO), and determined whether a full unbalanced power-flow function (UBLF) is mandatory (M) or desirable (D) [12]. The results of this evaluation are shown in Table 8-1; overall, UBLF is mandatory.

Table 8-1. Data Requirements for Top ADMS Advanced Applications

Network Data	Fault Location	FLISR	VVO/ IVVC	UBLF
Sequence Impedances for Lines, Transformers	M	M	M	M
Transmission Bus Equivalent Sequence Impedances	M			
Equipment Capacity & Voltage Ratings		M	M	M
Customer Energy Usage Data		M	M	M
Min/ Max Tap Ratios, Number of Tap Steps for Transformers (no-load tap and LTC)	M	M	M	M
Transformer and Capacitor Regulation Settings		M	M	M
Transformer Connections	M	M	M	M
Cap. Bank Size		M	M	M
Relay Trip Settings		M	M	M
Fuse Sizes		M	M	M
Substation Model	D	D	M	D

They went on to identify sources of the data used by these ADMS functions (i.e. the operational and measurement data required from a SCADA system), as presented in Table 8-2 [12].

Table 8-2. Operational Data Required from SCADA

Measurement Data	Fault Location	FLISR	VVO/ IVVC	UBLF
Real & Reactive Power or Current, Voltage & Power Factor	D	M	M	M
Voltage	D	D	D	D
Transformer and Regulator Tap Position	D	D	M	D
Fault Current	M	Determine the isolation zone	NA	NA
Fault Target	M	Requires fault indication from isolation/restoration devices to determine isolation zone	NA	NA
Breaker Lockout Status	NA	M	NA	NA
Cap. Bank Open/Close Status	NA	D	M	D

8.3 Vendor Details

Each ADMS implementation is unique and most platforms are built in base versions and then customized per individual utility requirements [27]. While there are many differences between each deployment, the underlying goals for deployment are often the same. As a result, vendors typically provide base components and add additional capabilities as requested. This approach results in numerous interfaces that are often treated as separate projects requiring integration [3] [4]. In such a varied market, it is important to know the product evolution and its development path: some products follow a SCADA product path (such as GE Alstom Alliance [31], Survalent [37]), others follow an OMS path (such as ABB [29] and Oracle [6]) or a combination of SCADA and OMS product paths (such as GE [31], EFACEC [43], Siemens [51], Schneider Electric [48]). Knowing the product development path can ease the systems integration and helps with pinpointing expected integration challenges. Table 8-3 presents a selection of ADMS vendors and their products.

Table 8-3. Partial List of ADMS Vendors

Vendors	FLISR	SCC, Power Flow, PRV	AFR, POS	CVR & VVO
ABB [29]	Yes	Yes	Yes	Yes
EFACEC ACS [43]	Yes	Yes	Yes	Yes
GE Alstom Alliance [31]	Yes	Yes	Yes	Yes
Oracle [6]	Yes	Yes	Yes	Yes
OSI [23]	Yes	Yes	Yes	Yes
Schneider Electric [48]	Yes	Yes	Yes	Yes
Siemens [51]	Yes	Yes	Yes	Yes
Survalent Technologies [37]	Yes	Yes	Yes	Yes

8.4 Current Trends and Strengths/Weakness

ADMSs are systems in continuous evolution and their enhancements are driven by the development of advanced applications intended to improve efficiency and resiliency in utility operations. Surveying the utilities that developed ADMS platforms [56], the most deployed advanced applications are

- **Fault Location, Isolation, and Service Restoration (FLISR)**: locates faulted equipment, automatically isolates it, and expedites power restoration using data from the OMS, the AMI, and the DERMS
- **Volt-VAR Optimization (VVO)**: optimizes the system to achieve reduced power losses, and implements CVR to reduce demand; data from the AMI, the DERMS, and the OMS are used
- **Distribution State Estimation (DSE) and Unbalanced Load Flow (UBLF) Analysis:** focuses on increasing operator situational awareness and minimizes costs of distributed grid intelligence expansion
- **Other Intelligent Initiatives**: switch order management, distribution automation (DA) and integration with advanced metering infrastructure/automatic metering reading (AMI/AMR).

One of the strengths of an ADMS platform is that it proves the ability to continuously adapt to the market changes and expectations such as the addition of DER and microgrids [37]. In the near future, the evolution of ADMS is expected to fully integrate the distribution system's operating environment [37].

ADMS implementations vary from one utility to the other and are typically driven by one or more implementation drivers. A survey performed by Accenture in 2015 indicated that the number of ADMS-adopting companies is continuing to grow, and these utilities now service 38 million customers [59]. A representative listing of ADMS-implementing utilities and their specific implementation drivers is presented in Table 8-4. This list does not include all utilities that have deployed ADMS technologies, and is only meant to illustrate a possible range of implementation drivers.

Table 8-4. Companies Adopting ADMS (as reported by Accenture in 2015)

Company	Implementation Drivers
Alabama Power	Electronic Mapping Operations and integrated Outage Management
Alliant Energy	Volt/VAR and Demand Reduction
Austin Energy	Reliability Improvement and Situational Awareness
B.C. Hydro	Customer Energy Reduction and VVO
Black Hills Co.	Planned Switching
COBB EMC	Reliability Improvements
DTE Energy	Reliability Improvements and Situational Awareness
Duke Energy	Volt/VAR and DER Integration
Florida Power and Light	Reliability Improvement and Power Flow Control
Georgia Power	Reliability Improvement
Hydro One	GE Integration and Reliability Improvements
NES	Volt/VAR
Oklahoma Gas and Electric	Volt/VAR and Demand Reduction
ONCOR	Operator Efficiency and Reliability Improvement
PPL	Reliability Improvement
Progress Energy	Volt/VAR and Reliability Improvement
San Diego Gas & Electric	Outage Management and Planned Switching
SNOPUD	Customer Satisfaction and Renewables Integration
ComEd	Electronic switching and operational map management

While many utilities have a desire for the capabilities that an ADMS can provide, the available technology is not always able to meet their needs. A 2015 survey of 198 distribution utilities in the United States revealed that most of the surveyed utilities expressed an interest in the same set of technologies [20], [5], [40]. These technologies include DMSs, OMSs, MDMSs, DRMSs, Substation Automation, SCADA, VVO, FLISR, and phasor measurement unit (PMU) integration. While the utilities expressed an interest in these technologies individually, they were not able to fully integrate the systems [20]. A graph illustrating the technologies adopted by different utilities is presented in Figure 8-2 [5]. As shown in Figure 8-3, the most integrated systems are those managing metering data and/or integrating metering data with an outage management system [5]. The plots in both Figure 8-2 and 8-3 are reproduced from previous PNNL reports.

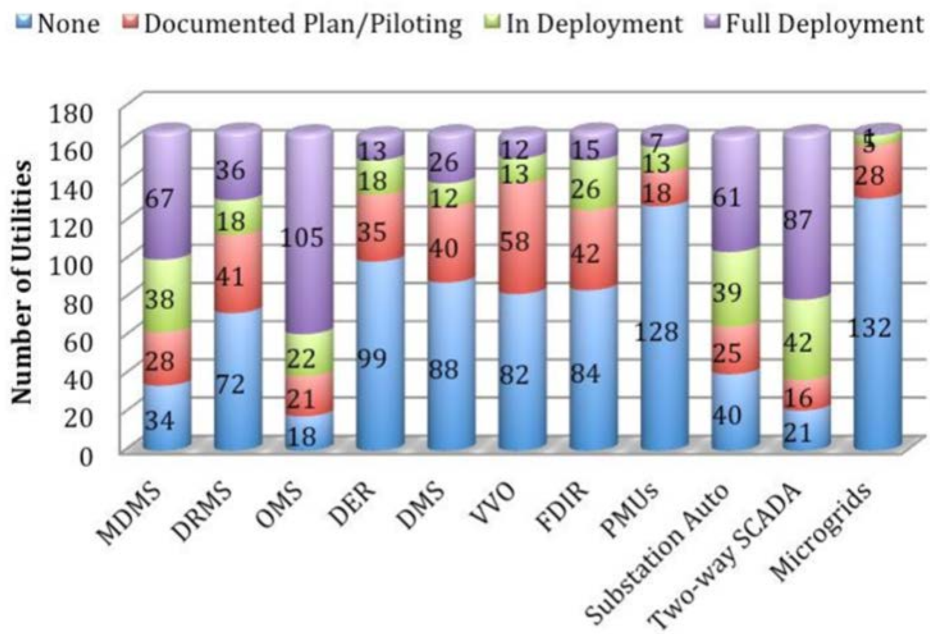


Figure 8-2. Deployment of ADMS Supporting Technologies and Capabilities

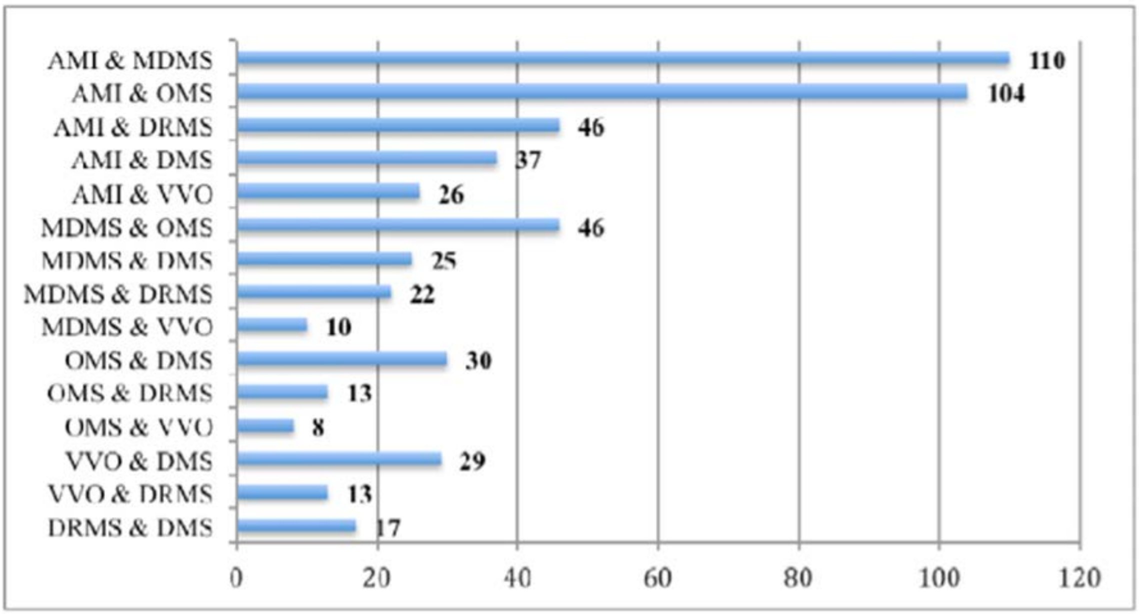


Figure 8-3. Number of Utilities with Integrated Capabilities and Functionalities

9.0 Gap Analysis for ADMS and Conclusions

The concept of an integrated distribution operational environment enabled by an ADMS has been around for some years, but the industry has not been able to bring the technology to the marketplace at a level of ease that utilities find acceptable. As a result, the current state of the art for ADMS is a large vendor-specific system that can only be afforded by the largest utilities. ADMSs are not available to the majority of utilities because of the time, cost, and need to commit to a single vendor across a range of systems. Three of the greatest barriers to wider spread deployment of ADMS are the inaccuracy of the underlying data model, complexity and cost of the integrated operating environment, and the lack of a broad community of applications developers. Until there are accurate models, cost-effective methods of integration, and a broad community of developers providing a wide range of application capabilities, deployment of ADMS technologies will lag.

9.1 The Application Gap

Once an integrated operational environment exists, it is necessary to implement the functionality necessary to make the system of value to the utility and its end-use customers. This is typically achieved through applications such as FLISR, VVO, and DR. Currently, there are a relatively small number of ADMS application developers because said applications are typically developed within the ADMS environment itself; as a result, there are few developers outside of the ADMS vendors. A transition needs to occur where less effort is spent on the integration of systems, and more effort is spent on the development of applications that provide benefits. This can only occur if the integration has been properly done. The development of an open architecture platform will enable a larger number of stakeholders to be ADMS application developers.

9.2 The Data Model Gap

The foundational layer of the ADMS is a solved three-phase unbalanced power flow solution. Every ADMS application from the core switching scenario builder, electronic map, to the advanced ones like FLISR, VVO/IVVC/CVR and others require the results of the power-flow solution of the most recent state of the network for their results to be truly valuable to the operator.

For the power-flow algorithm to solve effectively, it depends on an accurate power system model, which typically comes from the GIS, a system generally under the control of the asset management or the planners. This means that the GIS is typically a few days to a few weeks behind the as-built model of the power system network in the field. As ADMS' become more prevalent, working off an inaccurate model of the network is not adequate if the operators are expected to base decisions on this model.

For the future ADMS to work effectively, system operations needs to be identified as an important stakeholder of the GIS and the model that it holds.

9.3 The Integration Gap

The core concept of ADMS is to have all operational tools working in a common environment so that field measurements, data, and control signals can be accessed by all systems. To accomplish this, one option is for a utility to replace all of the existing systems with the products from a single vendor. While a single-vendor solution can address some of the integration issues, past deployments have proven that they still have challenges. Specifically, when a utility decides at a later date to replace a component with one that is not from the same vendor, it may not be possible. It is preferable to use open standards that allow for different vendor products to be integrated, as dictated by the technical and businesses needs of the utility. What more commonly occurs, is that a utility begins piece-meal integration of existing systems with new systems, which may not be provided by the same vendors. The integration challenges between the operational systems and the back-office systems represent the single largest challenge for ADMS design and deployment.

9.4 Lack of Implementation Experience

There are more than 3000 utilities in the US but less than 50 ADMS/DMS implementations, with many of them implemented in part only. Every AMDS/DMS implementation is a new experience in implementation and so takes 5-10 years for full implementation. This happens for several reasons.

- Bits and pieces of the systems that tend to be a part of the ADMS are already in existence at the utility. Examples of these legacy implementations include SCADA, OMS, and others. So, when a new implementation starts, the older implementations are not eliminated. Any new implementation needs to integrate with legacy systems that would otherwise traditionally be a part of the integrated ADMS system.

This situation is different at every utility – making every implementation a custom implementation.

- Unlike the transmission-EMS implementation, there is a lot of process/workflow built into the ADMS. These processes are very different at each utility thereby requiring either customization at the utility or a lot of flexibility in the vendor system design.
- Most DMSs or ADMSs have reached some level of maturity only over the last 5 years. In comparison, transmission-EMSs first arrived in the early 70s and did not mature until mid-80s to mid-90s. Hence, one could argue that ADMS vendor systems are not yet mature, so that even the vendors are learning what utilities need in ADMS from implementation to implementation.

In the same vein, the utilities are also learning the art-of-the-possible based on their own and other implementations.

During all of this, the utility's needs are also changing with the rapid advance of the Smart Grid and newer devices that are being deployed on the distribution feeder in remote locations and near end-use customers; often referred to as "the edge".

9.5 Maintenance Gap

The ADMS is a complex system that requires maintenance at different levels. Any utility that implements one of these needs to plan for maintenance that is required for this system to function in an effective manner and deliver long-standing value to system operations.

- Model maintenance: The distribution "as-built" model changes several times in one day. So, the distribution model needs to be updated at least once a day to follow the field changes as closely as possible, allowing the operator and field personnel to operate the system during planned and unplanned work. Model update is a complex process starting from extracting the as-built model from the GIS (just the incremental model), importing it into the ADMS, verifying its validity, and then operationalizing the system for the operators. It is not a trivial task to do this without interrupting the ADMS.

- System maintenance: Given the recent nature of the ADMS systems, there are always bugs that are identified and vendors are routinely sending in patches to their software. These patches need to be coordinated and brought on line when appropriate.
- Third-party software maintenance: All ADMSs these days depend on third-party software such as ORACLE™, OSI/PI™, and others that tend to have their own update cycles. ADMSs tend to have many such software components from different third-party vendors that need to be tracked and coordinated to ensure that the ADMS operates effectively all the time.

9.6 Legacy Architecture Integration Gap

The ADMS integrates with several major systems such as the GIS, CIS, asset registry, and several others that tend to be built on legacy architectures, which tend to be on their own upgrade or replacement cycles. So, regardless of the state of the art implementation of an ADMS, it still needs to be able to integrate with older systems thereby requiring it to be able to support both new and legacy architectures.

9.7 Conclusions

The deployment of ADMSs has the potential to fundamentally alter the operations of distribution utilities, as they evolve into the future with the potential introduction and rapid acceptance of distribution markets, DERs, and more devices at the grid-edge. If the challenges of cost-effective integration and application development can be addressed, ADMS can become a practical option for utilities of all sizes. Once deployed, benefits will include increased operational flexibility, increased system efficiency, increased resiliency, and the ability to integrate higher levels of DERs.

In addition, as ADMSs continue to evolve, it can be a foregone conclusion that newer and more innovative architectures (e.g., cloud-based) will be defined and made available to the utility industry.

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