Distribution Management Systems Planning Guide

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EPRI Project Manager

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ABSTRACT

No portion of the electric power grid has been impacted more significantly by the Smart Grid concept than the electric distribution system. In the past, the distribution portion of the system received little attention compared to transmission and generation systems unless the lights went out. Since the dawn of the smart grid era, many electric distribution utilities have transitioned from (or are in the process of transitioning from) a mostly manual, paper-driven business process to electronic computer and communication-based decision support and control systems. At the center of attention is the Distribution Management System (DMS), which will almost certainly play a major role in the future as smart grid roadmaps become reality.

This report explains how electric utilities can successfully plan, implement and use DMS effectively to accomplish the desired objectives. This report provides a roadmap that electric distribution utilities can use as a guide in performing key DMS implementation activities starting with project inception to DMS contract award.

Results and Findings

Electric distribution utilities are just beginning to realize the potential benefits of the DMS concept. Many utilities have conducted limited scale demonstrations of selected advanced grid modernization functions, such as Volt VAR Control and Optimization (VVO), and Fault Location Isolation and Service Restoration (FLISR). While these demonstrations of individual grid modernization applications have generally proved successful, it is clear that widespread deployment of multiple grid modernization applications will require a well-coordinated approach to maximize the benefits of these systems. In addition, future deployments of Distributed Energy Resources (DERs), such as energy storage and distributed generators, will greatly increase the complexity of these individual systems and impose an additional burden on system operators who are tasked with the overall management of the distribution system. The DMS appears to provide an effective solution to these problems of increasing complexity using a single *as operated* distribution system model.

Challenges and Objectives

One of the most significant challenges associated with DMS implementation is the lack of a solid business case for making the significant investment associated with this system. To achieve a successful implementation, the DMS must address important business needs related to distribution system operation and performance. The DMS should support current business drivers as well as the electric distribution utility’s long range vision for distribution system operation and performance. This report includes guidelines for identifying the key short term and long term issues facing today’s electric distribution utilities. The report also includes guidelines on identifying DMS functions and technologies that can help satisfy these business needs.

One of the most significant challenges facing electric utilities that are seeking to deploy a Distribution Management System is lack of mature, field-proven vendor products. While numerous demonstration projects are currently underway, most of these projects utilize standalone controllers or SCADA rule-based systems that are simplistic relative to the more sophisticated (and more flexible) DMS model-driven solutions and heuristic auto-adaptive approaches. Many system vendors offer DMS solutions that are based on these more sophisticated design approaches, but few are mature, field proven products. This report includes information to assist the utility company in identifying and evaluating various vendors.

Applications, Value, and Use

This project developed guidelines for dealing with the challenges listed above and numerous other challenges that are detailed in the other sections of this report. These guidelines are based on EPRI experience, research, and analysis, as well as lessons learned from various electric distribution utilities and research activities from the academic community. During this project, EPRI conducted DMS workshops and seminars, participated in IEEE working groups on DMS, and participated in various industry forums to discuss issues and challenges facing utilities that are deploying DMS.

These findings are documented in this report which will serve as a valuable reference manual for electric distribution utilities that are contemplating DMS implementation. Electric utilities should use the results presented in this document to assist in the planning, design, specification, installation, commissioning, and verification of DMS.

Listed below are the key benefits that members will be able to achieve though this project.

- Members will be able to better plan DMS investments through an understanding of application requirements and performance under different circumstances.
- Members will be able to assess the economics and benefits of different applications as a function of their implementation costs.
- Members will gain valuable insights into the steps needed to plan and procure a DMS, and will also learn about economic justification of a DMS project.

EPRI Perspective

The Grid Modernization Project Set develops and evaluates advanced distribution system applications for reliability improvement, system optimization, asset management, and distributed resource integration. These applications involve implementation of monitoring equipment (sensors), communications infrastructure, and advanced protection and control functions. The program will support utilities in the migration to distribution management systems with model-based management of the system. The DMS of the future will need to integrate many functions to optimize system performance, reduce losses, optimize voltage and VAR control, improve reliability through system reconfiguration and fast restoration, and integrate distributed resources. The project set builds on the analytical capabilities of the Open DSS software for analytical assessment of advanced distribution management functions and also works with member utilities to demonstrate advanced functions for development of application guidelines and identification of gaps in the technologies.

Keywords

Centralized architecture
Distribution management system
DMS business case
DMS opportunity matrix
Information technology
Operations technology

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

Today's electric distribution systems depend on intelligent field devices and control systems to maintain maximum efficiency, reliability and performance without compromising safety and protection of distribution assets. These intelligent field devices and systems must perform properly in an increasingly dynamic operating environment resulting from high penetrations of distributed generating resources, significant new loads such as electric vehicle chargers, and the growing need for improved efficiency and energy conservation. Distribution control center operators are transitioning from mostly manual, paper-driven processes to computer-assisted decision support systems that help manage this dynamic operating environment and the growing array of intelligent field devices and information sources.

No portion of the electric power grid has been impacted more significantly by the Smart Grid concept than the electric distribution system. In the past, the distribution portion of the system received little attention compared to transmission and generation systems unless the lights went out. Since the dawn of the smart grid era, many electric distribution utilities have transitioned from (or are in the process of transitioning from) mostly manual, paper-driven business process to electronic computer and communication based decision support and control systems.

At the center of this transformation is the Distribution Management System (DMS), which is a decision support system to assist distribution system operators, engineers, technicians, managers, and other electric utility personnel in optimizing the efficiency, reliability, and overall performance of the electric distribution system without compromising the safety of the workforce and general public and the protection of the distribution assets.

This research effort provides information utilities need to plan, implement, and commission DMS and Distribution Automation (DA) facilities that will work in concert to achieve these goals and objectives.

Objectives

The DMS is a relatively new concept that involves many new business processes, advanced applications, and sophisticated system integration concepts. Most of these business processes, applications and integration techniques are relatively new to the industry, and have not reached a level of maturity that would enable an electric utility to deploy such concepts without a high degree of uncertainty and risk. The main objective of this research effort is to provide insights based on the past experiences of utilities, consultants, and vendors who have DMS deployment efforts already completed or well underway.

The report provides guidance on how to get started with a DMS implementation project, including guidance on how to *get started on the right foot*. The process begins by defining key terms (for example, *What is a DMS?*) and definitions. This is followed by a roadmap for DMS Implementation to guide the utility through the following items:

- Defining business requirements
- Identification of DMS applications and architectures to satisfy these business requirements
- Development of technical specifications and procurement documents
- Soliciting and evaluating proposals from DMS vendors, system integrators, and other proponents
- Contract negotiations.

The report also summarizes strategies for designing, building, testing, installing, commissioning, and sustaining a DMS.

Scope

This project provides guidelines and detailed information needed to plan for the DMS implementation. The project includes criteria (an *opportunity matrix*) for selecting DMS applications to address important business drivers, functional descriptions of key applications, guidelines for identifying a generalized (conceptual) architecture, implementation and sustainment strategies, and other important information.

This project set develops and evaluates advanced distribution system applications for reliability improvement, system optimization, asset management, and distributed resource integration. These applications involve implementation of monitoring equipment (sensors), communications infrastructure, and advanced protection and control functions. The program will support utilities in the migration to distribution management systems with model-based management of the system. The DMS of the future will need to integrate many functions to optimize system performance, reduce losses, optimize voltage and VAR control, improve reliability through system reconfiguration and fast restoration, and integrate distributed resources.

The project set builds on the analytical capabilities of the Open Distribution Simulator Software (OpenDSS) software for analytical assessment of advanced distribution management functions and also works with member utilities to demonstrate advanced functions for development of application guidelines and identification of gaps in the technologies.

The project set also supports a Distribution Management System Interest Group (DMSIG). This interest group provides an information sharing forum for development of requirements for DMS implementations, sharing experience from actual implementations, and brainstorming for future applications. Gaps identified will help EPRI in prioritizing future research in this project set.

This project also supports the efforts of the Institute of Electrical and Electronic Engineers (IEEE) Power and Energy Society (PES) Task Force on the Distribution Management System. The purpose of this task force is to foster the development of DMS concepts and to create industry standards for DMS deployment and integration.

Organization of the Report

This report includes the following seven sections:

Section 1 – Introduction: describes the background for this project, identifies the major objectives and scope of this project, and describes the content of each section of the report.

Section 2 – Introduction: defines Distribution Management Systems' key terms that are essential for understanding what a DMS is, identifies and describes the major DMS building blocks and distinguishing characteristics of a DMS , and provides other information that is needed to gain a basic understanding of what a DMS is and what benefits a DMS can provide. This section also describes important Information technology (IT) concepts that may be unfamiliar to operators and engineers but are essential for a successful DMS deployment.

Section 3 – Relating Business Needs to DMS Requirements: provides a strategy for identifying the specific utility's DMS requirements. As explained in this section, there is no one DMS solution that exactly matches the specific needs of every electric utility. Rather, a utility's DMS requirements must be keyed to their specific business objectives and drivers, operating challenges, customer expectations, regulatory environment, and issues that are unique to every utility. The section includes a DMS *Opportunity Matrix* to assist the utility company in identifying DMS functions and technologies that may help address the business needs specific to that utility. This section also describes a strategy for identifying the business requirements that provide the foundation upon which the rest of the project is based.

Section 4 – Overview of DMS Requirements: This section describes, at a high level, the DMS application functions that are commonly included in the DMS. The purpose of this section is to identify representative requirements for each function. It is noted however that the specific applications being implemented and the specific requirements for each function may vary considerably from utility to utility.

Section 5 – Convergence of Operations Technology and Information Technology: With increased collaboration of IT and OT, for the reasons discussed above, there are potential benefits in harmonizing their standards, guidelines and practices developed in the IT industry. This report explores these potential benefits by examining the key similarities and synergies as well as key differences between IT and OT practices for the design, implementation, operation and maintenance of computer based systems used in distribution control centers. The objectives of this section include bridging knowledge gaps between persons whose background is primarily in electric distribution system operations and persons with a background in IT, identifying areas where IT practices make sense in the operations environment and areas where there is not a good fit.

Section 6 – DMS Procurement Strategy: This section provides guidelines on procuring the equipment, software, and services that are usually needed for successful DMS implementation. This includes conducting a Request for Information (RFI) process, a Request for Proposal (RFP) process, bid evaluation, vendor selection, and contract negotiation.

Section 7 – Summary of Findings, Conclusions: This section summarizes the important findings, conclusions, and recommendations of this technical update, including suggestions for future research and technical updates.

2
INTRODUCTION TO DISTRIBUTION SYSTEMS

This section defines key terms that are essential for understanding what a DMS is, identifies and describes the major DMS building blocks and distinguishing characteristics of a DMS, and provides other information that is needed to gain a basic understanding of what a DMS is and what benefits a DMS can provide. This section also describes important information technology (IT) concepts that may be unfamiliar to operators and engineers but are essential for a successful DMS deployment.

What is a DMS?

There is no widely accepted industry definition of what a DMS is. Due the lack of a widely accepted industry standard definition for DMS, the following definition has been adopted:

"A DMS is a decision support system that is intended to assist the distribution system operators, engineers, technicians, managers and other personnel in monitoring, controlling, and optimizing the performance of the electric distribution system without jeopardizing the safety of the field workforce and the general public, and without jeopardizing the protection of electric distribution assets."

Listed below are several key points pertaining to this definition:

- The DMS should be viewed as a tool that assists the distribution system operators in the control center and in the field in performing their duties. DMS is not intended to replace human judgment and decision-making.
- DMS users are not limited to distribution system operators in the control center and in the field. DMS stakeholders and users also include engineers who may use the DMS for engineering analysis and studies, technicians who may use the DMS for troubleshooting and maintenance, and managers who may use the DMS for oversight and overall decision-making support.
- The DMS should play a key role in improving (optimizing) the efficiency, reliability and overall performance of the electric distribution system. Optimizing distribution system performance is often the primary motivator for DMS deployment. Advanced applications that assist in determining operating actions needed for improved performance are one of the key distinguishing factors of the DMS.
- The two most fundamental operating objectives – safety and asset protection – must never be compromised by the desire to improve performance. In fact, the major driving factors for DMS deployment often include ***improving*** safety and asset protection.

DMS Basic Building Blocks

The DMS concept is best described by looking at the DMS component parts or basic building blocks that comprise the DMS.

Distribution SCADA System

The foundation on which DMS is based is the Distribution Supervisory Control and Data Acquisition (DSCADA) system (see Figure 2-1). The DSCADA system provides the *field-facing* interface that enables the DMS to monitor the distribution field equipment in real-time (measurements made and reported in one minute or less on average) or near real-time (measurements made and reported every 10 to 15 minutes on average). DSCADA also enables the DMS to initiate and execute remote control actions for controllable field devices in response to operator commands or application function control actions. Examples of control actions include opening/closing a medium voltage line switch, raising/lowering a voltage regulator tap-setting, and switching a capacitor bank on or off.

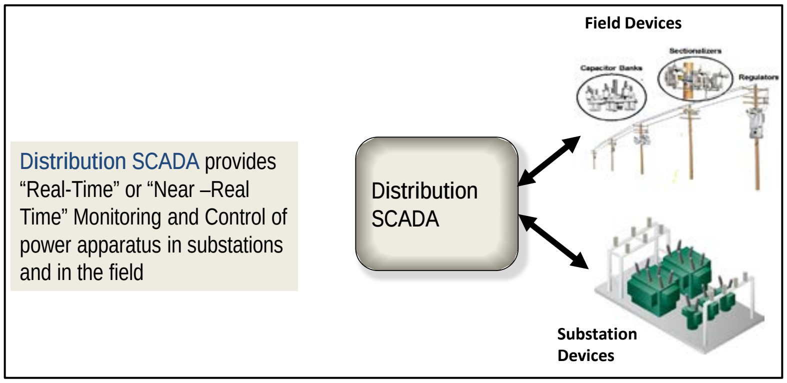


Figure 2-1
Distribution SCADA System

The degree to which distribution field devices are monitored and controlled by DSCADA varies widely from utility to utility. Many utilities have implemented DSCADA facilities for their electric distribution substations. However, far fewer utilities have implemented continuous monitoring and control of power apparatus that is installed out on the feeders themselves (outside the substation fence). A growing number of electric distribution utilities are currently implementing DSCADA for feeder devices as part of their grid modernization strategy. The ability to monitor and control feeder devices such as automated line switches and reclosers, switched capacitor banks, voltage regulators, and the ability to continuously monitor standalone distribution sensors (faulted circuit indicators (FCIs), current/voltage sensors, and so forth), are seen as essential for improving the overall performance of the distribution system.

As the penetration level of Distributed Energy Resources (distributed generators, energy storage devices, and so forth) continues to grow, these devices will have a significant impact on overall distribution system performance. As a result, continuous monitoring and control of these Distributed Energy Resources (DERs) may be needed. An approach to DER monitoring and control that is being researched by EPRI is the concept of a DER Management System (DERMS) which handles the direct interface to DERs for monitoring and control purposes rather than DSCADA. The DMS will obtain DER-related information as needed via enterprise system integration techniques such as Enterprise Service Bus (ESB). Figure 2-2 illustrates the separation of DSCADA and DERMS functionality for field device monitoring and control.

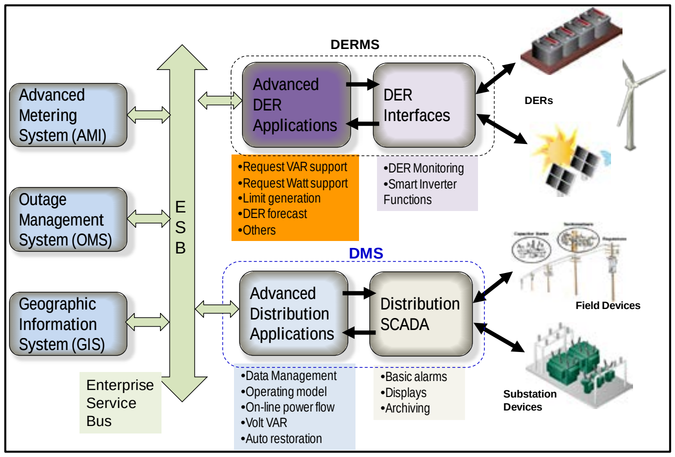


Figure 2-2
Separation of DSCADA and DERMS Functionality

Field facing interfaces to other grid modernization devices such as plug-in electric vehicles (PEVs) and advanced metering infrastructure (AMI) are expected to be handled in much the same manner as DERs. That is, the interface to advanced customer meters will most likely be handled by a Meter Data Management System (MDMS) which exchanges data as needed with DMS via ESB or other integration technique. Similarly, an Electric Vehicle Management System (EVMS) may handle the interface to a PEV charging infrastructure.

The DSCADA building block may also include some basic functionality, such as simple alarm checking, graphical user interface (GUI) for viewing data (tabular and schematic displays), and data archiving. However, more advanced functionality such as geographic displays and distribution system modeling are usually not considered part of DSCADA.

Advanced Distribution Applications

The next major DMS building block is the advanced distribution applications that use the information acquired by DSCADA to improve overall distribution system performance. Advanced applications build on DSCADA monitoring and control capabilities to provide electronic decision-making and automatic control capabilities for system *optimization*.

Advanced distribution system applications that determine control actions needed to optimize distribution system performance would execute such actions via DSCADA. The addition of advanced distribution applications provides a clear distinction between DMS and DSCADA. Figure 2-3 shows the interaction between the advanced applications and DSCADA building blocks.

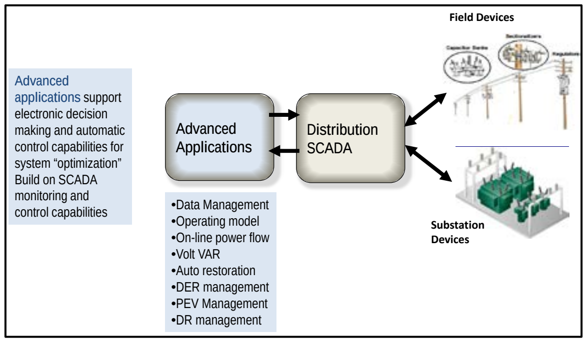


Figure 2-3
Interaction Between Advanced Distribution Applications and DSCADA

Examples of advanced distribution applications that are often included in this DMS building block are listed below. Note that this is just a partial list of the DMS advanced application suite. The Overview of DMS Functions (Section 4) of this report includes somewhat more detailed descriptions of these application functions.

Distribution System Model: An electrical representation of the physical characteristics and topology (connections between devices) of the electric distribution system. The Distribution system model may also include representation of the customer loading characteristics. The distribution system model is a key application that enables many of the other DMS applications.

Geographical User Interface (GUI): The DMS application suite almost always includes a geographically correct graphical user interface. For example, the DMS is usually able to show feeder map style displays with dynamically updating real-time and near real-time information superimposed on the map displays.

On-Line Power Flow: The On-Line Power Flow (OLPF) advanced application uses the distribution system model and available DSCADA data to compute the electrical conditions at any point on the feeder, including points that are not equipped with physical monitoring facilities. The OLPF is one of the most important DMS application functions because it enables numerous other applications, such as switch order management, to operate.

Switch Order Management: Switch Order Management (SOM) enables the distribution system operators and operations support staff to create and validate switching orders needed to isolate portions of the distribution system that are being repaired or maintained while providing electrical service to as many customers as possible.

Volt-VAR Optimization: This application identifies a coordinated set of control actions for distribution voltage regulating and VAR control devices that are needed to achieve utility-specified operating objectives (improve voltage profile, reduce electrical losses, lower demand, promote energy conservation, and so forth).

Optimal Network Reconfiguration: Identifies a set of line switching actions that can be used to achieve better load balance between interconnected feeders, improved voltage profile, or other utility-specified objective function.

Predictive Fault Location: Uses fault magnitude from substation intelligent electronic devices (IEDs) along with the distribution system model to predict the probable fault location, thus enabling more precise dispatching of field crews and faster service restoration.

Interfaces to External Systems

Another important DMS characteristic is the integration of advanced distribution applications and DSCADA facilities with other corporate enterprise systems, such as Geographic Information System (GIS) and the Outage Management System. Figure 2-4 shows the addition of corporate enterprise integration facilities to the set of DMS building blocks.

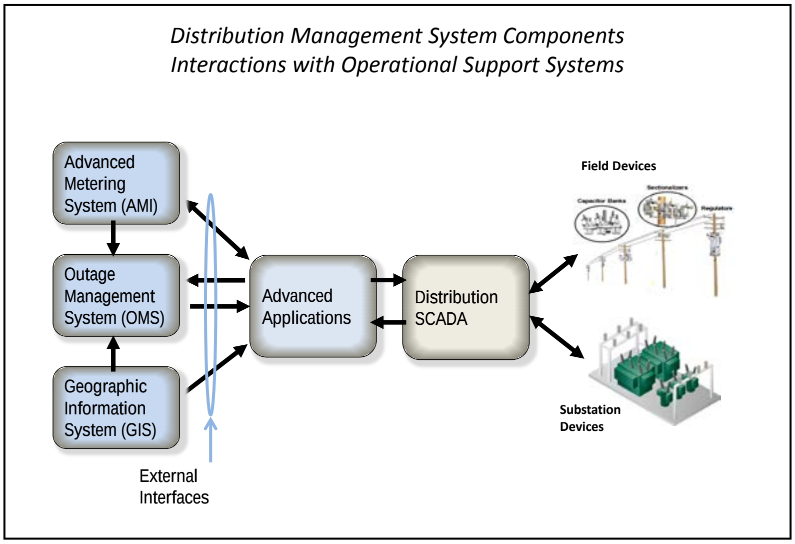


Figure 2-4
Corporate Enterprise System Integration

The purpose of each interface is summarized briefly below.

Geographic Information System (GIS): The GIS is a data repository containing detailed information about the electric distribution *physical* assets (poles, conductors, transformers, line switches, capacitor banks, voltage regulators, and so forth). The detailed information typically includes information about the physical characteristics and electrical characteristics (electrical impedance, efficiency, and so forth), of each device along with the geographic location (latitude and longitude) of each device. This information is used to construct and maintain the distribution system model used by many advanced DMS functions. The GIS is also used to build and maintain a similar model used by the Outage Management System (OMS). Note that the OMS version of the model usually only contains the feeder topology, not the electrical impedance and other information needed to run a load flow.

Outage Management System (OMS): The OMS performs many essential functions needed to assist distribution system dispatchers when customers are experiencing service interruptions. One of the key OMS functions is *fault location prediction*. The OMS applies individual customer outage telephone calls (or, more recently, *last gasp* messages from AMI meters) to its distribution system model to determine which calls/messages appear to be related to the same outage event. After the calls/messages have been grouped, the OMS uses the model to search *upstream* (closer to the substation) to determine which fault interrupting device operated for this event. This information is used to direct field crews to the approximate location of the root cause of the outage event. OMS often includes facilities for dispatching first responders and field crews to the outage location for fault investigation, damage assessment, and repairs.

Meter Data Management System: The Meter Data Management System (MDMS) is responsible for acquiring and processing readings from AMI meters. MDMS is primarily intended to support the revenue billing process. However, MDMS may support a myriad of additional functions such as theft detection, outage detection (*last gasp* messages), service restoration verification, and transformer load management. DMS advanced applications have many potential uses for AMI data, such as accurate determination of customer loading on a near real-time basis. The AMI system may also be used to implement demand response actions and execute other customer load control actions. Note however, that to date, AMI data resources is for the most part a largely untapped resource for advanced application beyond revenue billing.

Note: GIS, OMS, and MDMS are just a few of the corporate enterprise systems that are included in the DMS architecture. Further DMS integration requirements are described in the Overview of DMS Functions (Section 4) of this report.

DMS Distinguishing Characteristics

This section identifies several key factors to help in explaining the differences between a DMS and ordinary DSCADA.

Model-Driven Applications

One of the key characteristics to distinguish a DMS from ordinary DSCADA is the use of *model-driven* advanced distribution applications. By comparison, non-DMS solutions often rely on a fixed set of operating *rules* (for example, *If a specified condition exists, then perform a specified control action*). Model-driven solutions are better able to effectively handle varying operating conditions such as feeder reconfiguration and the on-again/off-again behavior of wind powered and solar powered distributed generators. When varying operating conditions exist, the model can be automatically or semi-automatically updated to reflect the *as operated* condition of the electric distribution system. On the other hand, DSCADA *rule-based* logic often have difficulty handling variable operating conditions because the operating rules become overly complex (unwieldy). Figure 2-5 depicts the mechanism used to keep the DMS *as-operated* model in synchronism with actual field conditions. The Overview of DMS Functions (Section 4) includes additional information about the distribution system model.

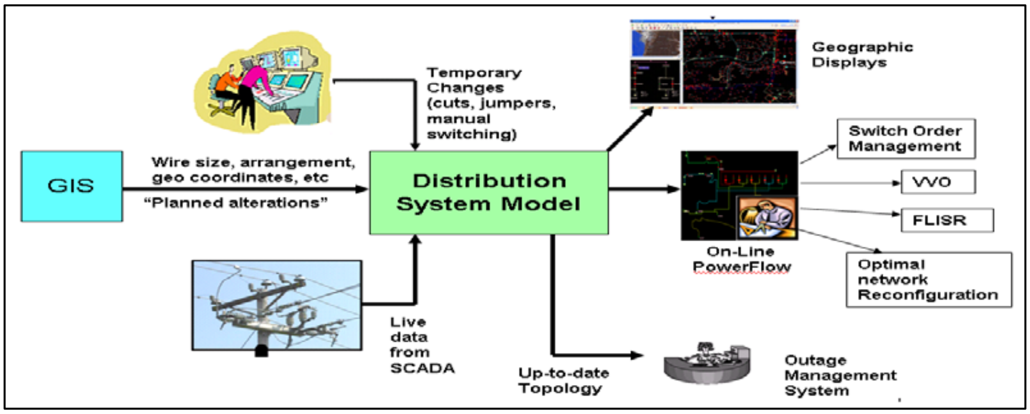


Figure 2-5
The *As-Operated Distribution* System Model

Advanced Visualization Techniques

Another distinguishing characteristic of the DMS is its use of advanced display technologies that allow the distribution system operator to more effectively visualize the operating conditions on the electric distribution system and interact with the advanced applications that use these visualization techniques. Earlier DSCADA systems relied primarily on tabular information displays supported by limited graphic displays. In most cases, the DSCADA graphic displays were *schematic* one line displays like the one shown in Figure 2-6 (a) that lacked detail, scale, and geographically correct orientation. The DMS is able to furnish graphically correct *feeder map* style displays that include dynamically updating graphical depiction of the electric distribution facilities with the correct geographic style superimposed on a depiction of the surrounding land base (streets, landmarks, and so forth). A representative DMS-style geographically correct display is shown in Figure 2-6 (b). Some DMS offerings also include *Google Earth* style displays in which electric distribution company assets are overlaid on the photographic Google Earth images.

(a) Schematic View (b) Geographic View

Figure 2-6
Schematic and Geographic Displays

Another feature of DMS style displays is its advanced pan-zoom full-graphic capabilities that enable the user to view portions of the system. Zoom capabilities allow the user to get a closer view of the facilities in question (zooming in) or view the facilities at the *50,000 foot* level (zooming out). Panning enables the user to move the displayed imaged in any direction (North, East, South, and West) to view facilities that are currently not shown on the screen.

Centralized or Decentralized Architecture (or Something In-Between)

A common misconception about the DMS is that it always uses a *centralized* architecture, which is a system design in which all of the system applications software and control logic resides in data processing equipment that is located in a control center, data center, or other facility that is far removed from the actual electric distribution assets. This centralized architecture (depicted in Figure 2-7) is just one of many possible approaches.

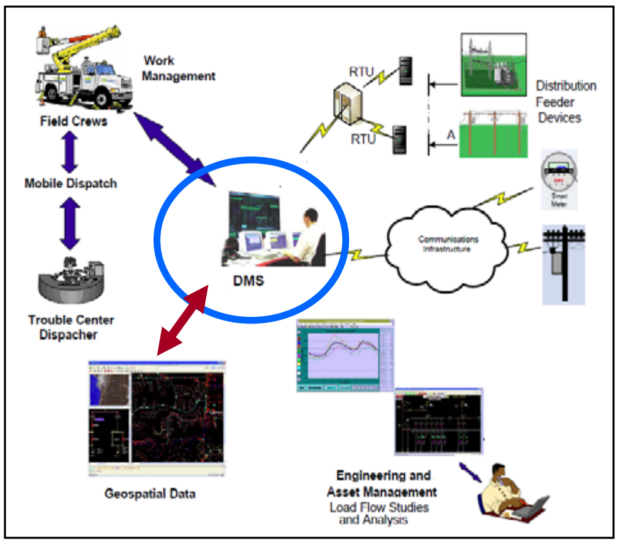


Figure 2-7
DMS Centralized Architecture

Alternatively, some or all of the DMS may be *decentralized*. With this approach, a significant part of the DMS software and control logic resides on intelligent data processing devices, (programmable controllers, *smart* remote terminal units, intelligent electronic devices, and so forth), that are physically located in electric distribution substations, in enclosures installed out on the feeders themselves (outside the substation fence), and other field locations. Figure 2-8 depicts a completely decentralized DMS architecture.

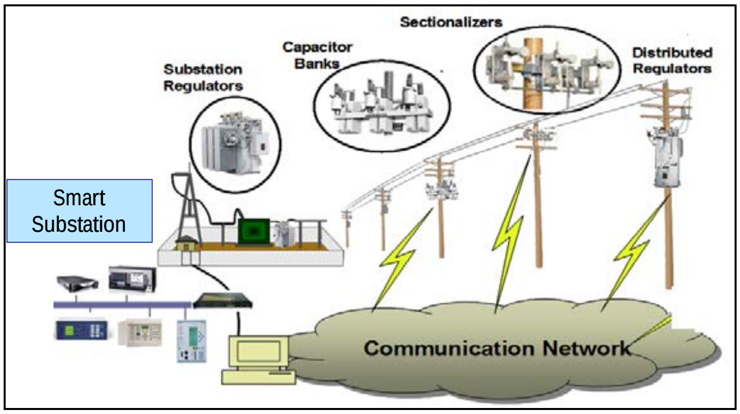


Figure 2-8
Decentralization of DMS Functionality

Most actual DMS implementations have an architecture that includes a combination of centralized and decentralized components. This is referred to as a *hybrid* architecture, which is depicted in Figure 2-9. DMS Procurement Strategy (Section 6) of this DMS Implementation guide includes guidelines for determining what portions of the DMS should be centralized and which portions should be decentralized.

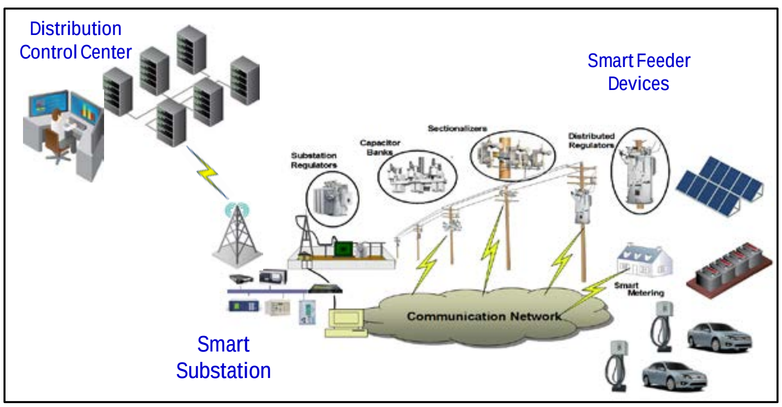


Figure 2-9
Hybrid DMS Architecture

Key Terms and Definitions

This section defines key terms and definitions that are used quite frequently when discussing DMS system design. Table 2-1 provides brief descriptions and discussions of key terms referenced in this document.

Table 2-1
Key Terms and Definitions

Term	Definition
Batch Processing	Performing a particular operation automatically on a group of files with a single command rather than manually opening, editing and saving one file at a time. For example, graphics software that converts a selection of images from one format to another would be a batch processing utility. Batch processing is often scheduled. This term is used by both IT and OT.
Business Intelligence (BI)	Business intelligence (BI) is the ability for an organization to take all its capabilities and convert them into knowledge to support better business decision-making. This produces large amounts of information that can lead to the development of new opportunities. Identifying these opportunities, and implementing an effective strategy, can provide a competitive market advantage and long-term stability within the organization's industry. BI technologies provide historical, current and predictive views of business operations. Common functions of business intelligence technologies are reporting, online analytical processing, analytics, data mining, process mining, complex event processing, business performance management, benchmarking, text mining, predictive analytics and prescriptive analytics.
Class Diagrams	Class diagrams describe the structure of a system by showing the classes, their attributes, operations (or methods), and the relationships among the classes. This is helpful in data modeling and object oriented programming.
Cloud Computing	Cloud computing is the use of computing resources (hardware and software) that are delivered as a service over a network (typically the Internet). The name comes from the use of a cloud-shaped symbol as an abstraction for the complex infrastructure it contains in system diagrams. Cloud computing entrusts remote services with a user's data, software and computation.
Common Information Model (CIM)	The Common Information Model (CIM), a standard developed by the electric power industry that has been officially adopted by the International Electrotechnical Commission (IEC 61968 and IEC 61970), aims to allow application software to exchange information about the configuration and status of an electrical network. **CIM supports SOA implementation and is often implemented in XML.** **The Common Information Model concept is also common to IT**. In computing, Common Information Model is a standard that defines how managed elements in an IT environment are represented as a common set of objects and relationships between them.
Data Warehouse (DW)	A data warehouse (DW) is a database used for reporting and data analysis. The data stored in the warehouse are uploaded from the operational systems (such as ERP, CIS, and AMI). The main source of the data is cleaned, transformed, cataloged and made available for use of data mining, online analytical processing, market research and decision support.

Table 2-1 (continued)
Key Terms and Definitions

Term	Definition
Database Administrator (DBA)	A database administrator (DBA) is responsible for the installation, configuration, upgrade, administration, monitoring and maintenance of databases in an organization. The role includes the development and design of database strategies, monitoring and improving database performance and capacity, and planning for future expansion requirements. They may also plan, co-ordinate and implement security measures to safeguard the database. This position typically resides in IT.
Database Management System (DBMS)	A database management system (DBMS) is a software package with computer programs that controls the creation, maintenance, and use of a database. A database is an integrated collection of data records, files, and other objects. A DBMS allows different user application programs to concurrently access the same database. DBMSs may use a variety of database models, such as the relational model or object model.
Demand Response (DR)	In electricity grids, demand response (DR) is similar to dynamic demand mechanisms to manage customer consumption of electricity in response to supply conditions, for example, having electricity customers reduce their consumption at critical times or in response to market prices. The difference is that demand response mechanisms respond to explicit requests to shut off, whereas dynamic demand devices passively shut off when stress in the grid is sensed. Demand response can involve actually curtailing power used or by starting on-site generation which may or may not be connected in parallel with the grid. This is a quite different concept from energy efficiency, which means using less power to perform the same tasks, on a continuous basis or whenever that task is performed. At the same time, demand response is a component of smart energy demand, which also includes energy efficiency, home and building energy management, distributed renewable resources, and electric vehicle charging.
DNP3 and ICCP	DNP3 (Distributed Network Protocol) is a set of communications protocols used between components in process automation systems. Its main use is in utilities such as electric and water companies. Usage in other industries is not common. It was developed for communications between various types of data acquisition and control equipment. It plays a crucial role in SCADA systems, where it is used by SCADA Master Stations (aka Control Centers), Remote Terminal Units (RTUs), and Intelligent Electronic Devices (IEDs). It is primarily used for communications between a master station and RTUs or IEDs. ICCP, the Inter-Control Center Communications Protocol (a part of IEC 60870-6), is used for inter-master station communications.
Enterprise Service Bus (ESB)	An Enterprise Service Bus (ESB) is an implementation of Service Oriented Architecture (SOA). The primary duties of an ESB are: • Monitor and control routing of message exchange between services • Resolve contention between communicating service components • Control deployment and versioning of services • Marshal use of redundant services • Cater for commonly needed commodity services like event handling and event choreography, data transformation and mapping, message and event queuing and sequencing, security or exception handling, protocol conversion and enforcing proper quality of communication service.

Table 2-1 (continued)
Key Terms and Definitions

Term	Definition
Ethernet vs. IP vs. TCP/UDP	Ethernet is a family of computer networking technologies for local area networks (LANs). Ethernet has largely replaced competing **wired LAN** technologies. The Internet Protocol (IP) is the principal communications protocol used for relaying datagrams (also known as network packets) across an internetwork using the Internet Protocol Suite. Responsible for **routing packets across network boundaries**, it is the primary protocol that establishes the Internet. The Transmission Control Protocol (TCP) is one of the core protocols of the Internet Protocol Suite. TCP is one of the two original components of the suite, complementing the Internet Protocol (IP), and therefore the entire suite is commonly referred to as TCP/IP. TCP provides reliable, ordered delivery of a stream of octets (data streams in bytes) **from a program on one computer to another program on another computer**. TCP is the protocol used by major Internet applications such as the World Wide Web, email, remote administration and file transfer. Other applications, which do not require reliable data stream service, may use the User Datagram Protocol (UDP), which provides a datagram service that emphasizes reduced latency over reliability. A layman's simplified view of Ethernet vs. IP vs. TCP/UDP: Imagine one of those pneumatic tube message systems. Ethernet is the tube used to send the message, IP standardizes the addressing in the envelope, and TCP/UDP standardizes the form letter in the envelope. Someone (an application) writes a letter and stuffs it in an envelope. Another person, a Network Interface Controller (NIC), looks at the address on the envelope, puts it in a tube, caps it off, stuffs it in the right door to bring it closer to its destination, then pushes the button. The tube gets carried to another door, where someone (a router) opens the tube, reads the address, puts it back in the tube, and sends it through another door. Eventually it arrives at its destination, where the NIC on the other side picks it up and gives it to the application.
Home Area Network (HAN)	A home area network (HAN) is a residential local area network (LAN) for communication between digital devices typically deployed in the home, usually a small number of personal computers and accessories, such as printers and mobile computing devices. An important recent application is to use HAN to implement smart appliance management functions.
IEC 61850	IEC 61850 is a standard for the design of electrical substation automation. IEC 61850 is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 (TC57) reference architecture for electric power systems. The abstract data models defined in IEC 61850 can be mapped to a number of protocols. Current mappings in the standard are to MMS (Manufacturing Message Specification), Generic Object Oriented Substation Events (GOOSE), SMV, and Web Services (coming soon). These protocols can run over TCP/IP networks or substation LANs using high speed switched Ethernet to obtain the necessary response times below four milliseconds for protective relaying.
Information Technology (IT)	Information Technology (IT) is an engineering discipline dealing with the use of computers and telecommunications systems and equipment to process, store, retrieve, analysis, transmit and manipulate data. The Information Technology Association of America has defined IT as *the study, design, development, application, implementation, support or management of computer-based information systems*.

Table 2-1 (continued)
Key Terms and Definitions

Term	Definition
Intelligent Electronic Device (IED)	An Intelligent Electronic Device (IED) is a term used in the electric power industry to describe microprocessor-based controllers of power system equipment, such as circuit breakers, transformers, and capacitor banks. It is mainly a power system OT term.
Location Agnostic Server	The technologies of *location agnostic servers* are new in the IT industry. Location agnostic design approach moves most of activities, messaging, and so forth, to the server-side from client-side in order to eliminate the dependency of locations.
MultiSpeak®	MultiSpeak® is a standard for enterprise application interoperability, specifically developed for electric power system utilities. The MultiSpeak Initiative is a collaboration of the National Rural Electric Cooperative Association (NRECA), leading software vendors supplying the utility market, and utilities. The MultiSpeak specification defines what data need to be exchanged between software applications in order to support the business processes commonly applied at utilities. It was originally targeted for small electric utilities. There are ongoing efforts to harmonize CIM and MultiSpeak.
Near Real-time Data	The term *near real-time* or *nearly real-time* in telecommunications and computing refers to the time delay introduced by automated data processing or network transmission between the occurrence of an event and the use of the processed data, such as for display or feedback control. For example, a near-real-time display depicts an event or situation as it existed at the current time minus the processing time, as nearly the time of the live event. The term implies that there are no significant delays in the presentment and use of the data. In many cases, processing described as *real-time* would be more accurately described as *near real-time* because time delays due to data processing inherently exist, albeit insignificant.
Open Database Connection (ODBC)	Open Database Connectivity (ODBC) is an open standard application-programming interface for accessing a database. By using ODBC statements in a program, you can access files in a number of different databases, including Access, dBase, DB2, Excel, and Text. In addition to the ODBC software, a separate module or driver is needed for each database to be accessed.
Operational Technology (OT)	Operational Technology (OT) is a specialized field that applies advanced computer software/hardware, electronic, and telecommunication technologies to enhance and automate power system operations, monitoring and control. Real-time performance and security are of particular concern to OT.
Programming Logic Controller (PLC)	A Programmable Logic Controller (PLC) or programmable controller is a digital computer used for automation of electromechanical processes, such as control of machinery on factory assembly lines, amusement rides, or light fixtures. It is a general IT term as well as OT.
Real-time Data	Real-time data denotes information that is delivered immediately after collection. There is no delay in the timeliness of the information provided. For example, real-time data is used for aviation, telecom network management, stability control of the electric power system, and so forth

Table 2-1 (continued)
Key Terms and Definitions

Term	Definition
Remote Terminal Unit (RTU)	A Remote Terminal Unit (RTU) is a microprocessor-controlled electronic device that interfaces objects in the physical world to a distributed control system or SCADA by transmitting telemetry data to the system, and by using messages from the supervisory system to control connected objects. It is mainly a power system OT term.
Service Oriented Architecture (SOA)	In software engineering, a Service-Oriented Architecture (SOA) is a set of principles and methodologies for designing and developing software in the form of interoperable services. These services are well-defined business functionalities that are built as software components (discrete pieces of code and/or data structures) that can be reused for different purposes. SOA design principles are used during the phases of systems development and integration. SOA generally provides a way for consumers of services, such as web-based applications, to be aware of available SOA-based services. For example, several disparate departments within a company may develop and deploy SOA services in different implementation languages; their respective clients will benefit from a well-defined interface to access them. XML is often used for interfacing with SOA services, though this is not required. SOA defines how to integrate widely disparate applications for a Web-based environment and uses multiple implementation platforms. Rather than defining an Application Programming Interface (API) for data mapping and transformation as used in the Enterprise Application Interface (EAI) integration approach, SOA defines the interface in terms of protocols and functionality.
Sequence Diagram	A sequence diagram in a Unified Modeling Language (UML) is an interaction diagram that shows how processes/application services, or objects, interact with one another **and in what order**. It is a construct of a Message Sequence Chart. A sequence diagram shows object interactions arranged in time sequence. It depicts the objects and classes involved in the scenario and the sequence of messages exchanged between the objects needed to carry out the functionality of the scenario. Sequence diagrams typically are associated with use case realizations of the system under development. Sequence diagrams are sometimes called event diagrams, event scenarios, and timing diagrams.
Stream Processing	Stream processing is a computer programming paradigm, related to SIMD (single instruction, multiple data), which allows some applications to more easily exploit a limited form of parallel processing. Such applications can use multiple computational units, such as the FPUs on a GPU or field programmable gate arrays (FPGAs), without explicitly managing allocation, synchronization, or communication among those units.
Swim Lane Diagram	A swim lane is a visual element used in process flow diagrams or flowcharts that visually distinguishes functional organization responsibilities for sub-processes of a business process. Each swim lane represents a functional organization such as call center, trouble outage dispatch, distribution system operator, operation engineer, field crew, and so forth There is often a *technology swim lane* at the bottom of the flowchart showing relevant information systems/applications. Use of an information system/application/database of an activity is illustrated by lines linking the activity (show in the swim lane of the responsible functional organization) to the information system/application shown in the *technology swim lane*.

Table 2-1 (continued)
Key Terms and Definitions

Term	Definition
System Development Life Cycle (SDLC)	The System Development Life Cycle (SDLC) framework provides a sequence of activities for system designers and developers to follow. It consists of a set of steps or phases in which each phase of the SDLC uses the results of the previous one. SDLC adheres to important phases that are essential for developers, such as planning, analysis, design, and implementation.
Transaction Processing	In computer science, transaction processing is information processing that is divided into individual, indivisible operations, called transactions. Each transaction must succeed or fail as a complete unit; it cannot remain in an intermediate state. Transaction processing is designed to maintain database integrity in a known, consistent state, by ensuring that any operations carried out on the system that are interdependent, are either all completed successfully or all canceled successfully.
Unified Modeling Language (UML)	Unified Modeling Language (UML) is a standardized modeling language for object-oriented software engineering. UML is used to specify, visualize, modify, construct and document object-oriented applications under development.
Use Cases	Use cases are a list of steps, typically defining interactions between a role and a system, to achieve a goal. This can be helpful in documenting business requirement. Both IT and OT use this concept.
Virtual Private Network (VPN)	A virtual private network (VPN) is a technology for using the Internet or another intermediate network to connect computers to isolated remote computer networks that would otherwise be inaccessible. A VPN provides security so that traffic sent through the VPN connection stays isolated from other computers on the intermediate network. VPNs can connect individual users to a remote network or connect multiple networks together.
XML	Extensible Markup Language (XML) is a markup language that defines a set of rules for encoding documents in a format that is both human-readable and machine-readable.

List of Acronyms

ADR	Auto Demand Response
AMI	Advanced Metering Infrastructure
BI	Business Intelligence
CAIDI	Customer Average Interruption Duration Index
CIM	Common Information Model (IEC 61978/61980)
CIS	Customer Information System
CMMS	Computerized Maintenance Management System
CORBA	Common Object Request Broker Architecture
DA	Distribution Automation
DB	Database
DBA	Database Administrator
DBMS	Database Management System
DCC	Distribution Control Center
DER	Distributed Energy Resources
DMS	Distribution Management System
DR	Demand Response
DR	Disaster Recovery
D-SCADA	Distribution SCADA
DW	Data Warehouse
EA	Enterprise Architecture
EAI	Enterprise Application Integration (application data integration via middleware)
EAM	Enterprise Asset Management
EI	Enterprise Integration
EMS	Energy Management System
ERP	Enterprise Resource Planning
ESB	Enterprise Service Bus (tools for service level integration of information systems)
ETL	Extract, Transform, Load (data interface)
FERC	Federal Energy Regulatory Commission (USA)
FFA	Field Force Automation
FLISR	Fault Location, Isolation, and Service Restoration

GIS	Geospatial Information System
GOOSE	Generic Object Oriented Substation Events
GPS	Global Positioning System
GUI	Graphical User Interface
HAN	Home Area Network
ICCP	Inter Control Center Protocol
IDS	Intrusion Detection System
IPS	Intrusion Prevention System
IEC	International Electrotechnical Commission (international standards organization)
IED	Intelligent Electronic Device
INOC	Integrated Network Operations Center
IVR	Interactive Voice Response
IVVC	Integrated Volt-VAR Control (sometimes referred to as VVO)
IT	Information Technology
KPI	Key Performance Indicators
LAN	Local Area Network
MAIFI	Momentary Average Interruption Frequency Index
MAS	Multiple Address System (point to multi-point communication, used in SCADA)
MDM	Meter Data Management
MMCC	Multimedia Customer Communications applications
MMS	Multimedia Messaging Service (a standard for telephone messaging systems)
MPLS	Multiprotocol Label Switching, mechanism in high-performance telecom networks
MWM	Mobile Workforce Management
NIST	National Institute of Standards & Technology (USA)
ODBC	Open Database Connection
ODS	Operation Data Store (SCADA/DMS/DA historian database)
OLAP	On Line Application Processing
OMS	Outage Management System
OT	Operational Technology
PLC	Programming Logic Controller
QA/QC	Quality Assurance/Quality Control

RCM	Reliability Centered Maintenance
RDBMS	Relational Database Management System
RF	Radio Frequency
RTU	Remote Terminal Units
SA	Substation Automation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDLC	System Development Life Cycle
SLA	Service Level Agreement
SMS	Short Messaging Service (cell-phone text messaging)
SOA	Service Oriented Architecture
SOM	Switch Order Management (a DMS application)
SOM	Service Order Management (a WMS and MWM application)
TNA	Training Needs Assessment
UML	Unified Modeling Language (an object modeling and specification language)
VVO	Volt/VAR Optimization (sometimes referred to as IVVC)
WAN	Wide Area Network
WIMAX	Worldwide Interoperability for Microwave Access (an RF technology)
WMS	Work Management System
XML	Extensible Markup Language

3
RELATING BUSINESS NEEDS TO DMS CAPABILITIES

This section provides a strategy for identifying the specific utility's DMS requirements. As explained in this section, there is no one DMS solution that exactly matches the specific needs of every electric utility (that is, no *one size fits all*). Rather, a utility's DMS requirements must be keyed to its specific business objectives and drivers, operating challenges, customer expectations, regulatory environment, and issues that are unique to every utility. The section includes a DMS *Opportunity Matrix* to assist the utility company in identifying DMS functions and technologies that may help address the business needs specific to that utility. This section also describes a strategy for identifying the business requirements that provide the foundation upon which the rest of the project is based

Identifying Business Drivers and Objectives

Most successful DMS implementation projects begin with a thorough assessment of the electric distribution utility's important business drivers and objectives. These business drivers and objectives provide the foundation upon which all DMS functional and technical design requirements are based. Since the DMS will be expected to serve the needs of the corporation over a long period of time (10-15 years at least), it is important to understand both the short term needs (over the next three to five years) and the long term needs (10-15 years).

It is often difficult to anticipate how the business needs of the electric power needs will change in the long term due to the potential impact of external influences that are beyond the control of the electric utility, such as changes in the political, regulatory, and economic environment. To address these uncertainties, the DMS must have a flexible standards-based design that can be expanded as needed in the future to accommodate new requirements that could not be anticipated at project inception. Such a design will help to ensure that the DMS does not become a *stranded* investment should major new needs arise in the future.

Identifying Overall Corporate Business Needs and Vision

The best way to gain a thorough understanding of corporate business objectives is to interview the persons who *own* the problems: the senior level executives. Besides providing the best available information on current business needs, the senior executives are the best resources for obtaining a *vision* on how these business needs are likely to change over the life of the DMS.

Identifying Near Term Operating Needs and Problems

In addition to determining the overall corporate objectives, the initial needs assessment must include a thorough review of current and anticipated operating problems and business needs of all stakeholders that may be impacted by the DMS. Requirements identified at this level tend to be more short term in nature and often include the need to address issues such as distribution system performance during normal and emergency conditions, increasing customer expectations, limited resources and razor-thin operating budgets, workforce turnover and attrition, growing complexity of the operating environment, and maintenance and sustainability of the assets. Like the business needs themselves, the list of stakeholders will vary significantly from utility to utility. Typically, the stakeholder list that should be included in the business needs discussion includes:

- Distribution system operators and dispatchers who manage electric distribution operations during normal operating conditions and emergencies (including major widespread storm emergencies).
- Field workforce for first response and switching; for performing new construction, repair, and maintenance of distribution field equipment located in substations; feeder locations (outside the substation fence); and in some cases, at customer sites where electric utility owned equipment is installed.
- Substation personnel, including those responsible for condition based maintenance.
- Information technology and communications (ITC) groups. This especially includes persons responsible for the overall ITC standards and key enterprise systems that must interface with DMS, such as Geographic Information System (GIS), Outage Management System (OMS), and Meter Data Management Systems.
- Engineers (planning, design, protection, and so forth), including engineers who support the operators and dispatchers as part of the operations group.
- SCADA and Communication Specialists; and
- Customer Service representatives who handle the *customer-facing* interfaces (for example, key accounts). This group may include persons who interface directly with customers who are planning to add distributed energy resources (including *microgrid* facilities) to their facility.

Representative Business Needs and Objectives

While the specific business needs and objectives will vary widely from utility to utility, most needs and objectives that are relevant for a DMS project fall into the general categories listed below. This list should serve only as a starting point for identifying the needs facing your specific company.

Safety of the Workforce and General Public

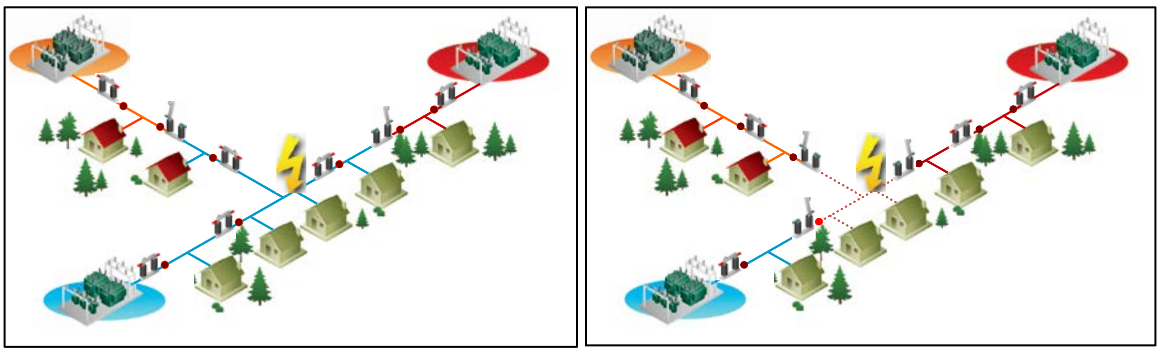
Maintaining the safety of the electric utility workforce and the general public is a fundamental and essential business objective that applies to all electric distribution utilities. The DMS should strictly enforce safety rules (tagging, permits, clearances, and so forth), improve operator awareness and facilitate rapid detection of potential safety hazards, provide mechanisms enable rapid detection of potential safety rules, and provide mechanisms such as remote monitoring and control to perform some hazardous operations from a safe distance.

Cost of Service

Just about every electric distribution utility seeks to lower its cost of service without adversely impacting the quality of service. DMS application functions can help the utility company achieve this objective by lowering electrical losses (improving efficiency), squeezing more capacity out of existing assets through improved monitoring and dynamic equipment rating, lowering equipment maintenance costs through condition based maintenance, and workforce productivity improvements such as electronic mapping and predictive fault location.

Customer Satisfaction

Another business driver that is common to all electric distribution utilities is customer satisfaction. Some of the important factors that influence customer satisfaction are the cost of electricity to the consumer (cost of service), the reliability and quality of service, and the perceived performance of the electric utility company during emergency situations. The DMS application suite includes numerous functions that can improve the reliability and quality of service in a proactive manner (before customer calls/complaints occur) by rapidly detecting abnormal conditions (service outages, voltage sags and surges that may impact the customer, and so forth), assessing the damage, and, in some cases, supporting a *self-healing* distribution network. Figure 3-1 depicts a set of interconnected distribution feeders that includes a Fault Location, Isolation, and Service Restoration (FLISR) function that provides a degree of *self-healing* following a permanent fault.



Before FLISR Operation After FLISR Operation

Figure 3-1
A Self-Healing Distribution Grid

The DMS, coupled with an Outage Management System (OMS), includes numerous *customer facing* applications that can help ensure that customers receive accurate and up-to-date information about ongoing events, including what the utility is doing in response to the event and when normal service will be restored. Recent storms that caused major outages in the Northeast US and other regions of the country have brought electric utility performance during major storms to the forefront.

Quality of Service

Maintaining a high level of service reliability and power quality is another important business driver for most electric distribution utilities. Customer power outages should be infrequent, and should be as short as possible in duration when outages occur. The number of momentary interruptions lasting one minute or less should also be minimized. Service utilization voltage measured at the customer meter should be within the voltage ranges established by ANSI and other standards bodies for all customers under all loading conditions. Voltage sags, surges, and other voltage quality events caused by a variety of reasons should be rapidly detected and corrected by the utility. An important business objective at many utilities is that the response to such events should be proactive, with such event detected and corrected by the utility before customers call to report the condition and complain.

The DMS should play a major role in accomplishing these business drivers through improved monitoring and detection of abnormal conditions, and should provide streamlined business process for responding to such events.

Worker Productivity

The need to maintain a highly skilled and effective workforce with razor-thin operating budgets is another important business objective for today's electric distribution utilities. Grid modernization, supported by the DMS and other external operation support systems, is transforming existing manual, paper-driven business processes to electronic, computer-assisted decision making with a high degree of automation. Productivity improvement measures included in the DMS should include streamlined business processes for electronic record keeping, permits and clearances, outage planning, fault investigation, and preparation of switching orders for planned and unplanned events.

Energy Efficiency

Most electric utilities are seeking ways to improve the overall efficiency of their power delivery systems (transmission and distribution), the objectives being to lower the carbon footprint, the need for capacity additions, and the overall cost of service. The DMS may include numerous application functions, such as volt-VAR optimization (VVO) and load balancing, which can help reduce electrical losses and peak demand on the power delivery system. Figure 3-2 depicts energy efficiency improvement through VVO operation.

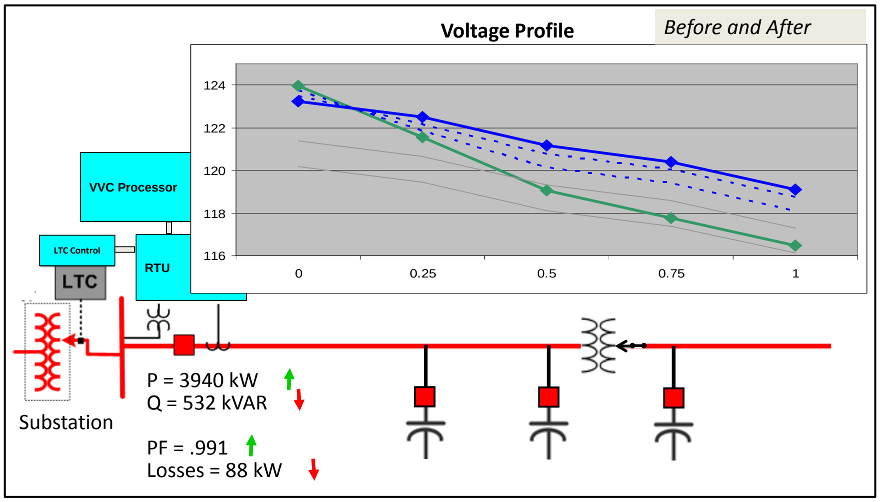


Figure 3-2
Efficiency Improvement Using VVO

Asset Utilization

Faced with limited and, in some cases, declining capital budgets, many utilities are seeking ways to avoid or at least postpone adding new facilities to their power delivery system. Achieving better utilization of existing power apparatus is one way to accomplish this business objective.

DMS application functions such as dynamic equipment rating and load balancing enable electric utilities to more effectively utilize the available capacity of its power apparatus, thus enabling the utility to *squeeze* more capacity out of existing assets.

Accommodate Distributed Energy Resources

One of the most significant changes associated with the modern distribution system is the appearance of high penetrations of Distributed Energy Resources (DERs). Electric utilities in many jurisdictions are facing mandates to provide significant portions of their load through renewable generating resources, such as wind power and solar photovoltaic power generators. The electric utility must be able to accommodate such new distributed generating resources without adversely impacting the quality of service on the electric distribution system. Accommodating these resources is especially challenging due to the highly variable nature of wind and solar powered generating units, which can produce unacceptable voltage and power swings on the feeders. Figure 3-3 depicts voltage swings produced by solar photovoltaic power fluctuations that should be mitigated to avoid adverse power quality issues.

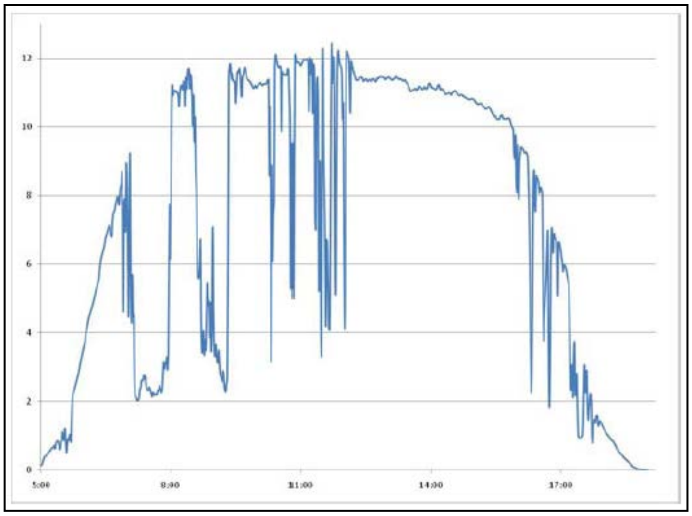


Figure 3-3
Voltage Swings caused by Solar Power Output Fluctuations

The DMS can include application functions that enable the utility to model the impacts of DERs and develop and execute operating strategies, such as advanced reactive power control, that can help to mitigate the adverse consequences of DERs and thereby accommodate addition DERs on the distribution feeders.

Relating Business Needs to DMS Requirements

Once the key business drivers of the electric utility have been identified, the next step is to relate these business drivers to DMS application functions and technologies that can help address these requirements. A valuable tool for relating business needs to corporate business drivers is the DMS *opportunity matrix*, which is shown in Figure 3-4.

DMS Functional Requirements	Enabling Function	Safety	Asset protection	Reliability	Efficiency	Peak shaving	Asset Utilization	Manage DERs	Manage Evs
Data Acquisition & Control	x								
State Estimation	x								
Graphical User Interface	x								
Historical Information System	x								
Distribution System Model	x								
Load Models	x								
Topology Processor	x								
On-Line Distribution Power Flow	x								
Intelligent Alarm Processing		x	x	x			x		
Control Room Operating Tools		x	x	x	x				
Short Circuit Analysis		x	x	x					
Switch Order Management		x	x	x			x		
Volt-VAR Optimization					x	x	x	x	
FLISR		x		x					
Predictive Fault Location		x		x					
Optimal Network Reconfiguration				x	x	x	x		
Short Term Load Forecasting				x	x	x		x	x
Dynamic Equipment Rating			x				x		
DMS Control of Protection Settings		x	x	x					
DER Management		x	x	x	x	x		x	
Demand Response Management				x		x			
Emergency Load Shedding		x				x			
EV Charging						x			x
Dispatcher Training Simulator		x	x	x	x	x	x	x	x

Figure 3-4
DMS Opportunity Matrix

The following sections describe how DMS application functions can assist in accomplishing the business drivers identified in the previous section.

Safety of the Workforce and General Public

As stated above, maintaining the safety of the electric utility workforce and the general public is a fundamental and essential business objective that applies to all electric distribution utilities. The DMS application functions listed below can assist in maintaining and improving distribution system safety.

- **Supervisory control of distribution feeder devices:** Operating distribution system equipment that is energized at 12 kV and higher can pose a safety hazard for persons located in the vicinity of the device, especially when the operating condition of the device is unknown. Distribution SCADA enables the distribution system operator to control the high and medium voltage devices via remote control with field personnel at safe distances. It should be noted that remote control can be a *double edged* sword when it comes to safety. This is due to the fact that it is possible to remotely control the equipment without the knowledge and permission of field personnel in the vicinity of the switch. Such safety hazards can be effectively managed by applying well-established safety rules (tagging, clearances, permits, and so forth) to the operation of DSCADA facilities.
- **Tagging, Permits, and Clearances:** The DMS may include application software to enable field workers to request all clearances, permits and safety tags needed to protect field workers from inadvertent energization of high voltage and medium voltage equipment that is being worked on. The DMS provides effective mechanisms to accurately create the necessary

permits, tags and clearances in accordance with established safety rules. The DMS will alert the system operators and field workers to other work in the vicinity of the proposed work, thus ensuring that all work is properly coordinated.

- **Switch Order Management:** The DMS Switch Order Management (SOM) function enables the system operator to create and validate complex switching orders accurately and efficiently, thus ensuring that the switching orders are written in accordance with established safety procedures and minimizing the chance of human error. The DMS can also transmit the switching orders to field crews electronically using mobile data terminals, thus minimizing the chance of human error in conveying switching instructions to the field. The DMS SOM function always alerts the system operator to other work being performed on the same feeder or in the same vicinity so that all work activities are properly coordinated with maximum awareness of current tags, clearances, and permits on the same feeder or in the vicinity of the proposed work effort.

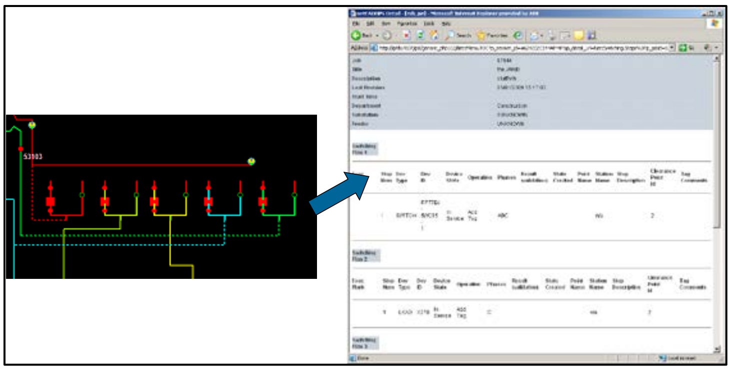


Figure 3-5
Using the DMS GUI to Create Switching Orders

- **Fault Location Isolation and Service Restoration:** The DMS FLISR function includes numerous features to ensure the safety of the field workers and the general public. When live line work is being performed on a given feeder, FLISR may be switched to *sectionalizer* mode, in which FLISR switches may be opened to isolate a fault. However, in a manner similar to the blocking of automatic reclosing (*hot line* tagging), switch closing and other automatic restoration activities are blocked to prevent re-energizing a section of feeder where field workers may be stationed. As another safety measure, switch closing is often automatically blocked after a specified time period (for example, two minutes following initial fault detection) to prevent re-energization of downed wires that may have drawn the attention of public bystanders.
- **Distribution Training Simulators:** DMS Distribution Training Simulators allow the utility to conduct realistic training exercises to ensure that the system operators are well versed in the procedures for recognizing and mitigating the consequences of safety hazards.

Cost of Service

The DMS may include several application functions that can assist the electric distribution utility in lowering the cost of service, as described below.

Volt-VAR Control and Optimization (VVO)

The Volt VAR Control and Optimization application function performs numerous functions that can help the electric utility lower the cost of service. VVO determines optimal settings for voltage regulator and distribution cap bank controllers that can accomplish numerous objectives, such as electrical loss reduction, power factor improvement, and peak shaving. The monetary benefits of reduced losses and peak demand reduction vary from utility to utility depending on tariffs that are in place. Vertically integrated utilities that generate all or part of the electric power consumed by their customers and utilities that pay *demand charges* to energy suppliers will directly benefit through lower supply costs. However, benefits to *wires only* companies may be limited to reduced or deferred expenditures on projects to increase capacity.

VVO may impact the number of voltage regulator tap change operations and switched capacitor bank operations, which in turn will have an impact on equipment maintenance as well as the useful lifetime of the equipment. Some utilities have reported that the number of tap changes and capacitor bank switching operations has decreased following VVO deployment. If so, lower maintenance cost can be expected for this equipment. However, other utilities have reported an increase in automatic switching operations (especially during *day on/day off* testing), resulting in increased maintenance for this equipment.

With DMS-based VVO, the electric utility is able to remotely monitor the operation of voltage regulators and switched capacitor banks to verify that these devices are operating properly. With remote monitoring and diagnosis, routine inspections of capacitor banks and voltage regulators may be eliminated.

Condition Based Maintenance

The DMS provides continuous monitoring and analysis of parameters that indicate the general health of distribution field equipment. Examples of monitored parameters include circuit breaker and recloser operation counters, contact wear indicators, circuit breaker timing, substation battery voltage performance, and transformer oil contaminant and moisture content. By basing maintenance and inspection requirements on equipment *health* measurements rather than fixed maintenance calendars, the electric distribution utility may be able to achieve significant cost savings without lowering the performance or reliability of the equipment.

Outage Planning

The Switch Order Management (SOM) function enables the utility to simulate planned outages using DMS short-term load forecasts for the planned outage time. The use of load forecasting enables to utility to anticipate potential overloads that may force the utility to halt the planned outage work in progress. Anticipating such problems in advanced will enable the utility to avoid the cost of work startup and shutdown efforts due to unanticipated loading constraints.

Electronic Records Management

With the DMS, numerous manual tasks and paper driven processes may be replaced with electronic and computer-assisted business processes that are more efficient and may produce significant cost savings to the utility.

Predictive Fault Location

Predictive fault location enables the utility to identify possible fault locations much more accurately than *distance to fault* information supplied by protective relay IEDs and OMS predicted fault interrupting device techniques. The result is that a smaller portion of the feeder must be patrolled to identify the specific damage location, which, in turn, means shorter fault investigation period. Such improvements may produce labor savings (contractor or overtime costs) and vehicle cost savings.

Customer Satisfaction

The DMS will support a number of applications that provide cost savings and improvements in the quality of service, which in turn can lead to increased customer satisfaction. As indicated in the previous section, the DMS can support a number of potential cost saving measures that may ultimately result in lower rates for electricity consumers.

The DMS application suite includes numerous functions that can improve the reliability and quality of service in a proactive manner (before customer calls/complaints occur) by rapidly detecting abnormal conditions (service outages, voltage sags and surges that may impact the customer, and so forth), assessing the damage, and, in some cases, supporting a *self-healing* distribution network. The DMS advanced application suite includes a Contingency Analysis function the continuously reviews plausible overload conditions and outage events that could produce unacceptable conditions on the electric distribution system, such as widespread outages. Armed with such information about plausible emergencies, the distribution system operator may proactively prepare for such emergencies by deploying peak shaving measures, load balancing, and where applicable, dispatching of energy storage and distributed generating resources that may help mitigate the consequences should such a contingency occur.

The DMS, coupled with an Outage Management System (OMS), includes numerous *customer*-facing applications that can help ensure that customers receive accurate and up-to-date information about ongoing events, including what the utility is doing in response to the event and when normal service will be restored. Recent storms that caused major outages in the Northeast US and other regions of the country have brought electric utility performance during major storms to the forefront.

Reliability and Power Quality

Maintaining a high level of service reliability and power quality is another important business driver for most electric distribution utilities. Customer power outages should be infrequent, and should be as short as possible in duration when outages occur. The number of momentary interruptions lasting one minute or less should also be minimized. Service utilization voltage measured at the customer meter should be within the voltage ranges established by ANSI and other standards bodies for all customers under all loading conditions. Voltage sags, surges, and other voltage quality events caused by a variety of reasons should be rapidly detected and corrected by the utility. An important business objective at many utilities is that the response to such events should be proactive, with such event detected and corrected by the utility before customers call to report the condition and complain.

DMS-Enhanced FLISR

The DMS application software provides useful enhancements to conventional FLISR that may enable downstream restoration activities to proceed in situations where conventional FLISR cannot restore power. For example, DMS FLISR enhancements may exploit energy storage or other distributed energy resources, fast demand response, and voltage reduction to reduce load and/or free up capacity so that a failed load transfer may be performed. Figure 3-6 illustrates the use of energy storage, fast demand response, and voltage reduction to restore a heavily loaded portion of a faulted feeder that would otherwise not have been restored.

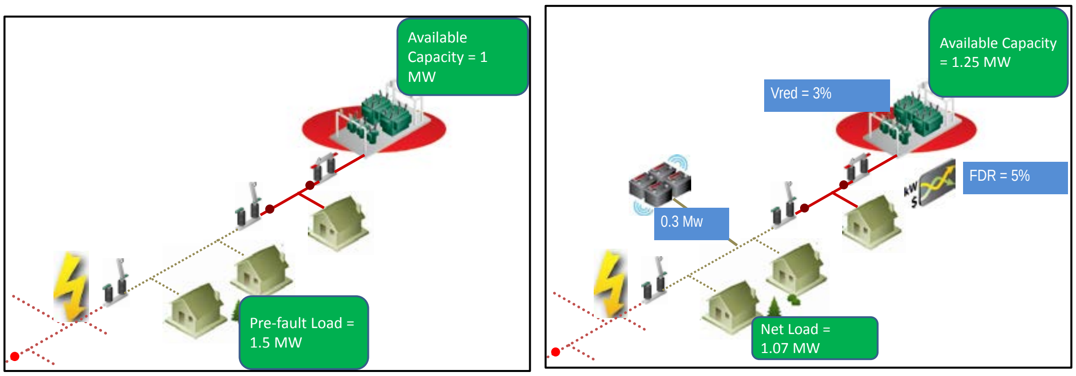


Figure 3-6
DMS Enhanced FLISR

Switch Order Management

Restoring service to customers who have lost power due to a feeder fault may require operating engineers to develop a complex switching order that involves a detailed analysis of loading and voltage constraints. The DMS SOM application software will facilitate the analysis of such complex situations, resulting in faster and more accurate development of switching plans needed to restore service. This, in turn, will result in an overall reliability improvement for the effected customers.

Predictive Fault Location

PFL provides more accurate estimation of probable fault location than conventional methods, such as distance-to-fault information supplied by protective relay intelligent electronic devices (IEDs) and fault interrupting device predicted by the OMS. The result is less patrol time and shorter overall fault investigation time, both of which translate into reliability improvement.

Dynamic Volt VAR Control

High penetrations of distributed generators, especially highly variable wind and solar powered generators, can produce rapid power swings and voltage fluctuations that may adversely impact the quality of power delivered to the electric distribution customers. Dynamic sources of capacitive and inductive VARs, managed by the DMS dynamic volt-VAR control (DVVC) application function, are able to mitigate this potential power quality problem. When voltage dips caused by sudden loss of DER power output occurs, the DVVC function will inject capacitive VARs at various locations to boost the voltage. Conversely, when voltage surges caused by sudden increases in DER power output occur, DVVC will inject inductive VARs at strategic locations. Figure 3-7 illustrates the impact of DVVC on feeders with a high DER penetration level.

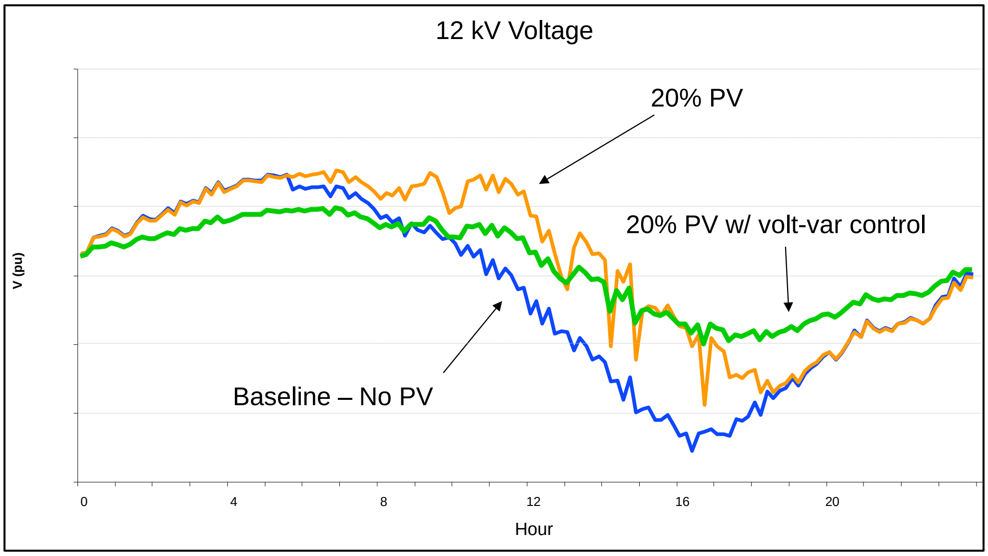


Figure 3-7
Power Quality Improvement with Dynamic VVO

Worker Productivity

Grid modernization, supported by the DMS and other external operation support systems, is transforming existing manual, paper-driven business processes to electronic, computer-assisted decision making with a high degree of automation. Productivity improvement measures included in the DMS include (but are not limited to) the items listed in the following sections.

Electronic Record Keeping

The ability to maintain as-designed, as built, and as-operated models of the electric distribution system using DMS application software has greatly streamlined the current processes that use red-line (additions) and yellow-line (deletions) markup of paper maps. The productivity improvement benefit gained from having a more streamlined process is potentially significant. Additional benefits are gained by reducing the latency associated with the manual update process.

Switch Order Management

The DMS includes facilities that will greatly streamline the process of developing and validating complex switching orders needed for work planning and for restoring service to customers whose electric service has been interrupted by a feeder short circuit. This functionality is especially valuable during major storm emergencies for which additional manpower may be enlisted for developing switching procedures and overall restoration strategies. In such circumstances, the worker productivity benefits due to reduced overtime and fewer outside contractors can be significant.

Predictive Fault Location

PFL will improve fault location accuracy and reduce the portion of the feeder that must be patrolled to determine the root cause of an outage. This function may be especially valuable during widespread emergencies when outside contractors may be enlisted to perform this duty.

Energy Efficiency

As stated earlier, many electric utilities are currently seeking ways to improve the overall efficiency of their power delivery systems (transmission and distribution), the objectives being to lower the carbon footprint, the need for capacity additions, and the overall cost of service. The DMS may include numerous application functions, such as volt-VAR optimization (VVO) and load balancing, which can help reduce electrical losses and peak demand on the power delivery system.

Power Factor Correction

The DMS Volt-VAR Control and Optimization is able to improve the power factor to near unity on targeted feeders through well-coordinated switching of distribution capacitor banks. Operating at close to unity power factor will reduce the current flow on the transmission and distribution system and thereby lower the total I^2R losses. The DMS provides several incremental benefits beyond conventional power factor correction techniques as listed below.

- **Monitoring of Volt VAR Control Devices:** The DMS uses its DSCADA capabilities to continuously monitor the operating status of voltage regulators and switched capacitor banks. Malfunctions of these devices (for example, blown fuses) are quickly detected so that a field crew can be dispatched to repair the malfunctioning device(s). In the past, device malfunctions were often detected during infrequent routine inspections, so some malfunctions were undetected for a considerable period of time. During that period, the operating benefits provided by the failed device were lost.
- **Operation following feeder reconfiguration:** Previous generation power factor correction facilities were designed to work best when the feeder is in its normal configuration. When the feeder is reconfigured for any reason, the device settings may no longer provide the expected benefits. In some cases, electric distribution utilities have elected to disable their volt-VAR control system following feeder reconfiguration. This problem does not exist on the DMS, which bases its control decisions on an *as-operated* model of the distribution system that is automatically updated when the feeder is reconfigured or other significant changes occur.
- **Voltage Reduction:** Many electric utilities are considering voltage reduction as a means of improving overall energy efficiency. The results of numerous demonstration projects and full-scale deployments, supported by the research efforts of EPRI and other industry research organizations, has shown that voltage reduction is an effective mechanism for reducing electricity demand and energy consumption without impacting the customer. Efficiency improvements of between 1% and 3% of total energy consumption have been reported for the voltage reduction efforts to date. The DMS model-driven voltage reduction application has numerous benefits compared other non-DMS approaches to voltage reduction:
    - Better coordination of a wide variety of volt-VAR control devices
    - Automatic adjustment of voltage reduction settings following feeder reconfiguration
    - Ability to use distributed energy resources as part of the VVO strategy.

- **Optimal Network Reconfiguration:** Another DMS-based efficiency improvement function is Optimal Network Reconfiguration (OPR). The ONR function can identify ways in which the electric utility can reconfigure a set of interconnected set of distribution feeders to accomplish a utility-specified objective function without violating any loading or voltage constraints on the feeder. At a minimum, the ONR objective functions may include:
  - Minimize total electrical losses on the selected group of feeders over a specified time period.
  - Minimize the largest peak demand among the selected group of feeders over a specified time period.
  - Balance the load between the selected group of feeders (that is, transfer load from heavily loaded feeders to lightly loaded feeders).
  - Combination of the objective functions listed above with a weighting factor for each.

Asset Utilization

Faced with limited and, in some cases, declining capital budgets, many utilities are seeking ways to avoid or at least postpone adding new facilities to their power delivery system. Achieving better utilization of existing power apparatus is one way to accomplish this business objective. DMS application functions such as dynamic equipment rating and load balancing enable electric utilities to more effectively utilize the available capacity of its power apparatus, thus enabling the utility to *squeeze* more capacity out of existing assets.

The DMS Dynamic Equipment Rating (DER) function will calculate thermal ratings (real-time ampacities) of substation transformers and distribution feeders (underground cables and overhead lines) on a real-time basis. The objective of this function is to calculate variable ratings based on actual loading and ambient conditions rather than worst-case weather and load assumptions. Weather data shall be used to support the dynamic equipment rating function.

Accommodate Distributed Energy Resources

One of the most significant changes associated with the modern distribution system is the appearance of high penetrations of Distributed Energy Resources (DERs). Electric utilities in many jurisdictions are facing mandates to provide significant portions of their load through renewable generating resources, such as wind power and solar photovoltaic power generators. The electric utility must be able to accommodate such new distributed generating resources without adversely impacting the quality of service on the electric distribution system. Accommodating such resources is especially challenging due to the highly variable nature of wind and solar powered generating units, which can produce unacceptable voltage and power swings on the feeders.

The DMS can include application functions that enable the utility to model the impacts of DERs and develop and execute operating strategies, such as advanced reactive power control, that can help to mitigate the adverse consequences of DERs and thereby accommodate addition DERs on the distribution feeders.

4
OVERVIEW OF DMS FUNCTIONS

This section describes, at a high level, the DMS application functions that are commonly included in the DMS. The purpose of this section is to identify representative requirements for each function. It is noted however that the specific applications being implemented and the specific requirements for each function may vary considerably from utility to utility.

The section describes (at a high level) *what* functions the DMS will be expected to perform, not *how* the function will be designed and implemented. The DMS vendors should be encouraged to propose a design that satisfies the utility's functional requirements while making best use of the vendor's standard offerings

Data Acquisition

The DMS should acquire real-time and near-real-time information about the current status, performance, and loading of distribution system power apparatus. *Real-time* information includes analog and status data reporting to DMS at least once every minute. *Near real-time* shall include equipment measurements and status coming from sources such as an advanced metering system that are updated less frequently than once every minute (for example, between once every five (5) minutes and once every fifteen (15) minutes). The input points acquired by DMS should include actual measurements as well as calculated values (*pseudo* points) that are derived from measured and manually-inserted quantities.

The DMS should be able to acquire analog inputs (continuously varying signals) and status inputs (signals that have a limited number of valid states). At a minimum, the following type of analog input points shall be implemented:

- Voltage magnitude measurements
- Current magnitude measurements
- Active power measurements
- Reactive power measurements
- Transformer tap positions

The following types of status input points should be implemented (at a minimum):

- Circuit breaker, recloser, and switch statuses
- Shunt capacitor switch statuses

The DMS data may be acquired from a variety of data sources, including (but not limited to):

- **Substation SCADA RTUs:** The DMS may acquire information about substation equipment (transformers, circuit breakers, voltage regulators, and so forth) via a direct connection to substation RTUs, data concentrators, or equivalent devices. If substation RTUs (or data concentrators) are connected to an EMS, then the DMS may acquire this data indirectly via an interface to the EMS (for example, an ICCP link with suitable security features).

- **SCADA facilities associated with field devices:** Some field devices (located outside the substation fence) may be equipped with local controllers, RTUs, and/or internal SCADA communication cards that can support DMS data acquisition functions.
- **AMI Meters:** Some DMS information may be acquired from Advanced Metering Infrastructure (AMI) meters installed at selected field locations (such as the substation end of the feeder) and selected customer premises.

The DMS should use a report-by-exception philosophy. Only the specified data that has changed by a specified amount should be transferred at any given time. The DMS should also include an *integrity check* feature that shall transfer the entire dataset at specified intervals.

Data Processing

The following processing should be performed each time new analog input data is acquired by the DMS:

- **Alarm Limit Checking**: The DMS should compare each analog input with normal operating limits and emergency limits that define the normal operating range and the emergency range of the variable.
- **Reasonability Limit Checking**: The DMS should compare each analog input value with high and low reasonability limits defined by the signal range of the variable. Input values outside this range indicate measurement failure, and should cause a high or low reasonability alarm.
- **Data Quality Processing**: The DMS should tag the value or state of each system variable so that all users of the value are aware of the quality (good, bad, questionable, manually substituted, and so forth) of the variable.

At a minimum, the DMS should perform the following processing of all status inputs each time they are acquired.

- **Normal/Off Normal Processing:** The DMS shall perform checking to determine if each status point is in its Normal state or its Off-Normal state.
- **Alarm Detection**: The DMS should perform alarm checking and annunciation for status inputs.
- **Sequence of Events Processing**: The DMS should be capable of accepting high accuracy time tags (plus or minus ten (10) milliseconds) assigned by the substation and field equipment and associated controls. These time tags should be retained by the DMS along with the associated point status. The DMS should use this information for producing time-sequenced reports (sequence of events reports).
- **Momentary Change Detection**: Status point changes that occur between scans should not be lost. The DMS should include a Momentary Change Detection (MCD) function to detect and indicate that two or more status changes have occurred in a particular status point since the last reported status.

DMS Control Outputs

The DMS should be able to control power system apparatus located at distribution substations and field locations (out on distribution feeders). The controlled power apparatus should include substation circuit breakers and reclosers, field reclosers, substation motor-operated disconnect switches (MODs), substation transformer load tap changers (LTCs), substation and field switched capacitor banks, voltage regulators, and other primary and secondary voltage equipment. The DMS should also be able to initiate load shedding of selected customers via an AMI system.

The DMS should support the following types of control actions:

- *Digital outputs*: on/off control commands that activate control output contacts.
- *Analog outputs*: control commands that change the settings in an intelligent controller associated with the device being controlled.

All supervisory control actions should follow a Select-Before-Operate (SBO) procedure that should protect against inadvertent execution of unwanted control actions. The SBO procedure should verify that the correct device has been selected via feedback from a hardware indicator associated with the selected device. The control menu presented to the Dispatcher should be placed in the display so that the device selected is not blocked from view. After confirming that the correct device has been selected, the Dispatcher should be able to proceed with or cancel the requested action.

The DMS should support a software tagging system that is consistent with the utility's safety protection rules. Tags are conditions that should be applied to DMS database values to call the users' attention to exception conditions for field devices and to inhibit supervisory control actions. As such, special precautions should be taken to ensure that no supervisory control action can be performed using a control inhibited device. In addition, special precautions should be taken to ensure that tags are not lost during system failover or switchover, even when these events occur simultaneously with tag application or removal.

Graphical User Interface (GUI)

The users should interact with the DMS via PC-based workstations installed at the Control Centers and various offices. The DMS user interface should allow authorized personnel to view measured and calculated real-time, near real-time, and historical data values, to initiate control actions (with suitable security limits and controls), and to interact with the DMS applications. The DMS should also include facilities to enable secure, view-only capability to authorized users located outside the control center.

The DMS user interface should be a workstation-based full-graphic display product. Full-graphic user interface features of the user interface should include panning, zooming, and de-clutter levels to allow the user to control the viewable area of the *world space* on display.

The DMS should include Areas of Responsibility (AORs) that should provide the means to route alarms, restrict supervisory control, and restrict data entry to those personnel having the associated responsibility and authority. It should be possible to assign responsibility for portions of the Distribution system to individual consoles by pre-defining groups of AOR's and assigning them to different consoles in the control room.

Convenient mechanisms should be provided to enable the user to request specific displays and navigate between displays. The amount of typing and the number of mouse clicks (for example, cursor target selections) needed to request any specific display should be minimized.

The DMS should include a variety of display types to support the visualization requirements of the DMS applications. At a minimum, the DMS displays should include the items listed below.

- One-line (*schematic*) diagrams showing the configuration, status, and loading of the distribution feeders, substations, and other power system facilities.
- Substation one-line (*schematic*) diagrams showing the configuration, status, and loading of the utility's internal substation configuration.
- Schematic diagrams for distribution field equipment (outside the substation fence). These displays should be generated automatically by the DMS on demand using geographically formatted displays of field information obtained from GIS.
- Map-style displays showing properly scaled and geographically correct depictions of the utility's distribution lines overlaid on street maps. It should be possible to view dynamic data, such as the open/closed position of each switch, the energization status of each device, and the loading of all equipment, on these displays.
- Switch-gear one-line (*schematic*) diagrams showing the fusing and switching configuration, status and loading of the internal switchgear configuration.

Intelligent Alarm Processing

The DMS should include Intelligent Alarm Processing functions to alert system users to abnormal conditions on the power system. The Alarm Processing function should also alert system users to DMS and communication equipment failures and other abnormal DMS conditions requiring attention. The DMS should include a variety of distinct alarm priorities that should determine the manner and priority in which each alarm is annunciated, acknowledged, and recorded.

The DMS should perform intelligent alarm processing to assist the operator in managing *bursts* of alarms that may occur during an emergency or combinations of alarms related to a single event. At a minimum, intelligent alarm processing should include the items listed below.

- Dependent alarms for which alarming of specified points should be enabled or disabled based on the status or values of another related data point.
- Preventing repetitive alarms for the same alarm condition.
- Combining related alarm messages. For example, a single alarm message *feeder ABC tripped* may be provided instead of multiple messages that convey the same information (breaker tripped, loss of voltage, loss of current).
- Prioritizing alarm messages and highlighting of the most urgent messages.
- Combining the alarm states of two or more alarms to produce a higher priority alarm message. For example, the DMS should be able to generate a single major alarm if two or more specified minor alarms exist at the same time.

- Suppressing alarms based on related conditions (that is, suppressing or enabling the alarm based on the value or state of another system variable). For example, if equipment associated with a voltage measurement is deenergized and that voltage value is approximately 0.0 KV, the DMS should consider that to be normal and should not raise any alarm. If the same equipment is energized and that voltage value is approximately 0.0 KV, the DMS should produce an alarm to indicate the possibility of a measurement failure.
- The intelligent alarm function should include *time sensitive alarming*. The DMS should monitor and alarm track time sensitive ratings on substation transformers, cables, and other equipment time sensitive ratings. The time sensitive alarm function should track the amount of time the short-term (for example, four hours) emergency loading on a substation transformer or cable has been exceeded and should alert the operator when the time limits are being approached. For example, if a substation transformer has exceeded its four-hour emergency rating for a user specified period (for example, 3.5 hours), the operator should be alerted.

Historical Information System

The DMS should include a Historical Information System (HIS) to store and retrieve system variable values, alarm and event messages, power system disturbance reports, and other calculated or acquired information. Real-time information shall be stored in the HIS on a periodic basis at user specified intervals and also on an *exception* basis when a variable changes by a user-specified amount since the last time it was stored. Information associated with events, such as an alarm or power system disturbances, shall be stored whenever such events occur.

Distribution Application Functions

The DMS shall include a suite of advanced applications for managing the operation of and optimizing the performance of the distribution system. The DMS advanced applications shall include functions that operate in real-time and near real-time to improve the visibility of and control the performance of the distribution system. The DMS shall also include *study* mode for all applications, which allows users to simulate the operation of the distribution system for performing *what if* studies, outage planning, and other such activities.

Distribution System Model

The DMS should include a detailed, up-to-date electrical and connectivity model of the electric distribution system as required by the DMS applications. There should be only one DMS model of the system used by all DMS advanced applications, such as on-line power flow and short circuit analysis. The DMS distribution system model should represent the entire distribution network that includes distribution feeders and distribution substation devices from the high-voltage side of the substation transformer (including the high side circuit breaker) down to the low voltage (secondary) side of the distribution service transformers. The DMS distribution system model should be a three-phase model that fully represents the unbalanced nature of the distribution system. The electrical model should include the entire distribution primary circuit, including main line portions of the circuit, feeder laterals, and underground loops that are tapped off the main trunk of the feeder. The distribution system model should accommodate three phase portions of the feeder as well as single phase and two-phase line segments and laterals.

The distribution model should include the *physical* characteristics of the circuit and the loading characteristics, as described below.

Physical Characteristics

The DMS shall provide proper handling of *underbuilds* identified by GIS. Underbuilds occur when:

- Distribution lines are on the same poles as transmission wires (which are not modeled in the same distribution GIS database);
- Two distribution primary lines are on the same pole (parallel circuits).

While most feeders are radial in nature (that is, there is one and only one path leading from a single feeder source to any point on the feeder) the DMS distribution system model and associated application software shall be able to handle looped and weakly meshed feeder configurations, circuits operating in parallel, as well as secondary networks.

The electrical model shall represent the entire electrical distribution system, including all elements of the electric distribution system from the transmission supply points (high voltage side of the substation transformers) to the low voltage (load) side of the distribution service transformers. Note that the *line of demarcation* between transmission and distribution may vary from utility to utility.

The transmission or subtransmission source(s) at each distribution substation may be represented by an infinite bus with dynamic source voltage angle and magnitude supplied by the EMS state estimator function. The equivalent impedance of the external network as seen from the high voltage buses of distribution substations buses should be provided. If the DMS operator is also responsible for the monitoring and control of a portion of the transmission and subtransmission system, then the appropriate portion of the transmission and distribution system should also be modeled.

Generators such as co–generators (cogens), non–utility generators (NUGs), independent power producers (IPPs), and other similar units shall be modeled. Generators shall be designated as either constant real power/constant voltage units (PV units) or constant real power/constant power factor units (PQ units). Generator active and reactive power limits shall be modeled by generator capability curve. In addition to synchronous reactance, the generator model shall also include sub-transient and transient reactances required for short circuit analysis.

To the fullest extent possible, the distribution system model shall be created and maintained with little or no manual intervention. The primary source of field (outside the fence) information for the model shall be GIS. The sources of information for the distribution substation portion of the distribution system model may include the EMS and other non-GIS sources. Manual entry may be needed to build the necessary substation models if this information is not available via an accessible electronic mechanism.

The GIS shall provide some basic *physical* information about each circuit, such as wire size and type and section length. The DMS, in turn, shall calculate resistance and reactance (including all significant mutual impedances) from these basic physical parameters. The GIS shall also provide information about the sizing and physical characteristics of other field components such as line capacitor banks, voltage regulators and distribution service transformers. Underground cables shall be modeled to include the cable impedance as well as charging admittance. The position of the individual cable in the ducts and manholes shall be provided from GIS.

The DMS shall identify all discrepancies, including missing or incorrect or insufficient data, so that it can be corrected in GIS. This requirement shall apply to data that it deemed to be available in the GIS but has not been entered or is entered incorrectly. To the extent possible, the DMS shall identify the proposed correction.

The DMS shall support incremental model changes. That is, when a small permanent change to the distribution system occurs, it shall be possible to update only those portions of the distribution system model that are affected by the change. It shall not be necessary to rebuild the entire model for each change in equipment and configuration. The DMS shall be able to perform incremental builds on a per-feeder basis.

The DMS shall provide a convenient mechanism for installing temporary changes to the electrical model. It shall be possible to change the open/closed position of a switch whose status is not automatically telemetered (*pseudo* point). In addition, the DMS shall support the addition of temporary cuts and jumpers (including jumpers between individual phases). The DMS shall allow an operator to change the network model to show a feeder being cut, grounded, or attached (jumpered) to another feeder or phase. When the repair is completed, it shall be possible to back the change out and return the network model to its original state. All such changes shall be automatically reflected in the DMS model. The DMS shall provide information about all such temporary changes to the utility's Outage Management System.

Load Models, Load Allocation and Load Estimation

The DMS shall include a mechanism to estimate the load on each distribution service transformer at a particular point in time. The Load Allocation and the Load Estimation functions shall provide the best estimate of KW and KVAR load levels to the Online Line Power Flow (OPLF) program. It shall be possible to use the Load Allocation and the Load Estimation function in both real-time mode and study mode.

The DMS Load Allocation function shall support the use of historical load curves (load *profiles*) that represent the characteristics of load types served by the utility. Load types supported by the DMS shall include different *conforming* loads (that is, loads with a profile that matches the utility's load survey data) and *non-conforming* loads (that is, loads with a unique profile that is significantly different than the utility's *standard* load profiles). Conforming load classes shall include numerous load types that go well beyond the basic residential, commercial, industrial load types. For example, supported load types may include:

- Agriculture – Commercial
- Agriculture – Residential
- Mining
- Educational Service
- Residential - High-Rise Apt Common (Electric Heat)

- Residential - High-Rise Apt Common (Non-Electric Heat)
- Residential - High-Rise Apt Suites (Electric Heat)
- Residential - High-Rise Apt Suites (Non-Electric Heat)

Load profiles shall consist of a pair of real power and power factor (or reactive power) for each load interval (15 minutes). Load interval size shall be configurable (for example, 5 minutes, 15 or 30 minutes, and so forth). The DMS shall interpolate between load survey points to determine load values at intermediate points between points on the curves. For example, with hour load survey data, half hourly data points shall be the average of the two adjacent hourly points. The DMS shall include a different set of load profiles for each season (winter, spring, summer, and fall) and for different types of days (weekday, weekend, holidays). The number of seasons and day types shall be configurable to satisfy the utility's specific needs.

The DMS shall be capable of using actual near-real-time distribution transformer loading measurements acquired from an AMI system or a Transformer Load Management (TLM) system in place of allocated values.

The Power Flow algorithm shall treat each load value as ***voltage dependent***. Load active and reactive powers shall be determined as a function from voltage at the bus where the load is connected. The polynomial representation, which is a combination of constant power, constant current, and impedance characteristics, shall be used.

The Load estimation application shall determine the best estimate of each distribution transformer load (KW and KVAR) based on the available real-time measurements, load profiles and real-time network topology. Load estimation shall use the accuracy class information assigned to each real-time measurement to discriminate between measurements based on the measurements' errors. Thus, load estimation shall match more closely the measurements which are more accurate (smaller errors assigned) then those measurements that are deemed less accurate (have larger errors defined in the assigned accuracy class) while determining KW and KVAR values of each load. Load estimation shall also perform measurement consistency checks and validation by fully exploring measurements redundancy wherever available in order to identify potentially bad measurements.

Plant Alterations

The DMS shall include a convenient mechanism for handling plant alterations (PAs), which are modifications and additions to the electric distribution system that have been planned and designed but have not yet been commissioned (energized). It shall also be possible to temporarily incorporate PA's in the distribution circuit model for study mode analysis. Conversely, it shall also be able to remove PA's that have been temporarily incorporated in the distribution circuit model.

The DMS shall store all changes to the DMS electrical model (incremental changes from GIS that could include PAs) along with the time and date the changes were commissioned. It shall be possible to restore (roll back) the electrical model to a condition it was in a specified time period in the past.

When a PA is energized, the equipment associated with the PA should be included in the distribution model and displayed as existing equipment, but this equipment shall still be flagged as *pending PA* to indicate that the changes have not yet been received from the GIS incremental update process. When the PA is posted to the GIS as-built layer, and the changes are received by the DMS, the DMS shall remove the PA highlighting on all displays showing the equipment in question.

Topology Processor

The DMS shall include a Topology Processor (TP) for performing various analyses of the distribution network configuration. The DMS TP function shall maintain static and dynamic connectivity models. Static connectivity shall define relationships such as static node-device relationship and organizational entities groupings. Dynamic connectivity shall account for switch statuses, device energization statuses and loops. The DMS TP function shall be able to perform the actions listed below.

- Locate an element of the distribution network (transformer, section, and so forth) by name or ID.
- Locate and mark supply paths of network elements.
- Determine and highlight the energization status of network elements
- Locate and highlight networks loops.
- Locate and highlight all network elements downstream a selected element.
- Locate and highlight neighboring feeders of a selected feeder that can serve as an alternate supply for the feeder).
- Color individual feeders.
- Color by voltage level.
- Color line segments with voltage magnitudes less than specified thresholds.
- Color line segments with loading greater than specified thresholds.
- Locate and highlight portions of the distribution feeder that are isolated from the utility's power grid and are being energized by IPPs and other distributed generating resources.

On-Line Power Flow

The DMS shall include an On-Line Power Flow (OLPF) program that is able to determine the electrical conditions on the utility's distribution feeders in near real-time. The OLPF shall provide the control center personnel with calculated current and voltage values in place of actual measurements and shall alert the operators to abnormal conditions out on the feeders, such as low voltage at the feeder extremities and overloaded line sections. In addition, other DMS application functions, such as Switch Order Management (SOM), Volt-VAR Optimization (VVO), and Fault Detection, Isolation, and Restoration (FLISR), shall be able to use the OLPF results to accomplish their specified functionality.

The OLPF shall use the distribution system model and load estimate provided by load estimation function in its calculations. The OLPF shall also use the available real-time statuses from the substation and feeder devices. The OLPF shall use voltages and phase angles obtained from the EMS state estimator at the injection devices (usually placed on high voltage transformer bus in distribution substations).

The OLPF program shall calculate current and voltage magnitudes and phase angles as well as real and reactive power flows and injections for the entire distribution system and shall present the results in various formats automatically and on demand. Convenient mechanisms shall be provided for viewing power flow summaries for a large area of the distribution system. It shall also be possible to view (on demand) the power flow results for a single point or section of the power distribution system.

The OLPF shall calculate all technical electrical losses (load and no-load losses) and real and reactive power flows and consumption, in the distribution system.

The OLPF shall be designed specifically for electric distribution systems. It shall provide a full three-phase unbalanced calculation, accommodating single-phase, two phase, and three-phase circuits and loads (balanced and unbalanced). The OLPF solution method shall be able to handle both radial and weakly meshed configurations and the wide range of X/R ratios encountered on distribution networks where mixtures of overhead lines and underground cables are commonplace.

Convenient mechanisms shall be provided for viewing the OLPF power flow results on schematic and geographic displays. At a minimum, the display mechanisms listed below shall be provided for viewing OLPF results.

- Automatically highlight sections of the feeder that are overloaded or experiencing under/over voltage conditions using color-coding (for example, sections of the feeder that are overloaded are color-coded red) or equivalent highlighting technique.
- Positioning the cursor on any feeder section (*mouse over*) shall result in the display of current flow and phase-neutral voltage at that point on the feeder.

Short Circuit Analysis

The DMS shall include a Short-Circuit Analysis (SCA) function that shall enable users to calculate the three-phase voltages and currents on the distribution system due to postulated fault conditions with due consideration of pre-fault loading conditions. The SCA function shall be able to calculate and compare fault currents against switchgear breaking capabilities or device fault-current limits. The SCA function shall also enable users to identify estimated fault location using measured fault magnitude, pre-fault loading, and other information available at the time of the fault.

The results of SCA shall be used for other applications like FLISR, Relay protection and coordination.

Switch Order Management

The DMS shall include a Switch Order Management (SOM) function to assist the Dispatcher in preparing and executing switching procedures for various elements of the power system, including both substation and field devices (outside the substation fence). The DMS SOM function shall assist the user in generating switching orders that comply with applicable safety policies and work practices. The SOM function shall support the creation, execution, display, modification, maintenance, and printing of switching orders containing lists of actions that are needed to perform the switching, such as opening/closing various types of switches, implementing cuts and jumpers, blocking, grounding, and tagging.

In addition to the computer assisted switch order generation facility described above, the DMS shall be able to automatically generate switching orders. With this auto-generate feature, the dispatcher shall select the power system device or portion of the system (*large area restoration*) to be isolated and worked on.

It shall be possible to execute defined switching orders in real-time and in study mode. Real-time execution shall be provided for switching orders that involve supervisory control commands. Study mode execution shall allow the Dispatcher to check out the switching order's potential impact on the power system, including possible current and voltage violations, at a specified time and date using the DMS OLPF program prior to actual execution. The DMS shall alert the dispatcher if any violations are detected during study mode execution of the switching order.

Volt-VAR Optimization

The DMS shall include a Volt-VAR Optimization (VVO) function that shall automatically determine optimal control actions to achieve specified *operating objectives* while maintaining acceptable voltage and loading at all feeder locations. In addition to the basic voltage and loading constraints, the VVO function shall not violate other constraints established by the utility, such as daily limits on the number of tap changer and capacitor bank operations.

VVO shall include the following utility-selectable operating objectives:

- Reduce electric demand;
- Reduce energy consumption
- Improve feeder voltage profile
- Maximize revenue
- Energy loss minimization/power factor improvement
- Weighted combination of the above

The VVO function shall operate either in closed loop or advisory (open-loop) mode. In advisory mode, the VVO function shall generate advisory control actions that may then be implemented by the dispatcher. In closed loop mode, the VVO program shall automatically execute the optimal control actions without operator verification. The VVO shall be executed periodically at a user-adjustable interval, upon occurrence of a specified event, (significant change in the distribution system such as significant load transfer, topology change and so forth), or manually by user.

The VVO function shall have a *failsafe* design. That is, no control action that would produce unacceptable voltage or loading conditions shall be requested by the DMS as a result of the failure of any DMS component or any other reason.

When an VVO component is out of service for any reason, (controller failure, loss of communications, controller manually bypassed, blown capacitor fuse, and so forth), the DMS shall continue to operate in these abnormal situations, if possible without producing unacceptable voltage and loading conditions, using the remaining DMS components.

Fault Location, Isolation, and Service Restoration

The DMS shall include a Fault Location, Isolation, and Service Restoration (FLISR) function that shall be used to improve the System Average Interruption Duration Index (SAIDI). FLISR shall provide SAIDI improvement benefits for a wide variety of feeder configurations with various levels of protection and automation, ranging from feeders in which the substation circuit breaker is the only controllable device and source of information to feeders that are equipped with automated line switches, ties switches, fault detectors, and other facilities for monitoring and control.

The FLISR main logic shall:

- Automatically detect faults;
- Automatically determine the approximate location of the fault (that is, the faulted section of the feeder between two feeder switches);
- Automatically isolate the faulted section of the feeder; and
- Automatically restore service to as many customers as possible in less than one (1) minute following the initial circuit breaker or recloser tripping.

The DMS shall analyze all available real-time information acquired from field devices, including fault detector outputs, fault magnitude at various locations on the feeder, feeder segment and customer meter energization status, and protective relay targets, to detect faults and other circuit conditions for which service restoration actions are required. All control actions identified by centralized FLISR shall be executed by issuing supervisory control commands to substation circuit breakers and reclosers and various feeder-switching devices (reclosers, load break switches, and sectionalizers that are equipped with supervisory control capabilities).

Optimal Network Reconfiguration

The DMS shall include an Optimal Network Reconfiguration function that shall identify ways in which the utility can reconfigure a user-selected interconnected set of distribution feeders to accomplish a user-specified objective function without violating any loading or voltage constraints on the feeder. The entity to be used in ONR shall be selected by user. (For example, division (area of a few substations), one substation and so forth) At a minimum, the DMS ONR function shall enable the user to achieve the objective functions listed below:

- Minimize total electrical losses on the selected group of feeders over a specified time period.
- Minimize the largest peak demand among the selected group of feeders over a specified time period.

- Balance the load between the selected group of feeders (that is, transfer load from heavily loaded feeders to lightly loaded feeders).
- Or a combination of the first three objectives with a weighting factor for each.

The ONR function output shall include a list of recommended switching actions and a switching plan to accomplish these actions along with a summary of the expected benefits (for example, amount of loss reduction).

Short Term Load Forecasting

The DMS shall include a Short Term Load Forecast (STLF) function that shall use historical load and weather data to forecast the system load automatically every hour, for a 168-hour (7-day) rolling forecast. Weather data shall be used to support the short-term load forecast function. The STLF results shall be available for viewing and outage planning and shall also be used by other DMS application functions that require an estimate of expected peak loading in the near term, such as FLISR, Switch Order Management (SOM), Network Reconfiguration, and Large area restoration.

STLF shall use both a weather-adaptive and a similar-day forecast methodology to obtain the most accurate prediction. It shall be possible to assign weighting factors to the results of each methodology to obtain weighted average forecast. The load forecast shall be based on historical load measurements or, in the future, actual meter readings obtained from AMI for the specified feeder on a *similar day* during the most recent past years. At a minimum, *similar* days shall be selected based on day of week (weekend, holiday) and month or season.

Dispatcher Training Simulator

The DMS shall include a distribution-training simulator (DTS) that shall provide a realistic environment for hands-on dispatcher training under simulated normal, emergency, and restorative operating conditions. The training should be based on interactive communication between instructor and trainee. The DMS training simulator shall include a complete replica of the real-time DMS user interface plus the operating model that shall simulate the real-time analog telemetry and status changes (elements' models shall be the same).

The DMS training simulator shall serve two main purposes:

- Allow utility personnel to become familiar with the DMS system and its user interface without impacting actual substation and feeder operations; and
- Allow utility personnel to become familiar with the dynamic behavior of the electric distribution system in response to manual and automatic actions by control and protection systems during normal and emergency conditions.

The DTS shall be considerably more than a simple data *playback* facility. The DTS shall predict (compute) the behavior of the power system under normal load circumstances and during simulated disturbances. For example, when a switch is opened by the instructor, the current through the switch shall automatically go to zero. The event shall be properly reflected on trainee's screen as open switch and coloring for non-energized state. In other words, the distribution system model at the trainee's console shall respond to all dynamic changes caused by instructor. The DTS shall fully emulate all monitoring and control capabilities of the real-time system such as alarming, tagging and AOR functionalities.

To support this sophisticated functionality, the DMS training simulator shall include dynamic modeling of the distribution system that shall simulate the expected behavior of the electric distribution system in response to disturbances introduced by a training supervisor. The DMS training simulator shall include either the same real time model of the distribution system as it is in the control center or from selected saved cases that represents the distribution system at specific date and time. The training simulator shall include dynamic load models (profiles) together with forecast total feeder load that shall be used to determine current and voltage values along the feeder during normal conditions. This information shall be displayed on the simulator operator consoles as though the simulated values were actual field measurements.

The training simulator shall enable the user (instructor) to introduce equipment and control failures to the system and the simulator shall calculate and present the expected result to the trainee. The instructor shall be able to place simulated single- and multiphase faults at any location along the feeder using the simulator's supervisor console, and the simulator shall (in turn) calculate and display the expected fault current magnitude and resultant protective device operation(s).

It shall also be possible to introduce events into the DTS to simulate equipment failures, faults, or other anomalies. Following the introduction of the event, the DTS shall automatically simulate the operation of the actual automatic control equipment, such as protective relays and reclosers that are installed in distribution substations and in the field (outside the substation fence).

Dynamic Equipment Rating

The DMS shall include a Dynamic Equipment Rating (DER) function shall calculate thermal ratings (real-time ampacities) of substation transformers and distribution feeders (underground cables and overhead lines) on a real-time basis. The objective of this function shall be to calculate variable ratings based on actual loading and ambient conditions rather than worst-case weather and load assumptions. Weather data shall be used to support the dynamic equipment rating function.

Substation transformer ratings shall be based on:

- Recent loading history
- Internal temperature measurements (for example, top oil, bottom oil, and hot spot temperatures for substation transformers)
- Status of forced cooling systems (for example, pumps and fans on substation transformers)
- Ambient temperature
- Season

Underground cable ratings shall be based on duct temperature measurements (where available), position in the duct bank.

DMS Control of Protection Settings

The DMS shall include application functions to assist the operators in switching between pre-established setting groups that are currently installed in the utility's protective relays and reclosers when the need arises. Several potential uses of this application are summarized below.

Fuse Saving Enable/Disable: Circuit breaker reclosing relays and line reclosers used by BCTC include user-selectable setting groups for *fuse saving* and *fuse blowing*. The DMS shall include a function that shall enable the user to switch between the *fuse saving* setting group and the *fuse blowing* setting group for user-selected circuit breaker reclosing relays located in substations and reclosers located in substations and out on the distribution feeders.

Cold Load Pickup Enable/Disable: Circuit breaker protective relays and reclosers may include user-selectable setting groups for handling normal service restoration and *cold load* pickup. Cold load pickup settings include additional time delays and higher pickup settings to prevent re-tripping when re-energizing the feeder or portion of the feeder following a lengthy (sustained) outage. The DMS shall include a function that shall enable the user to switch between the normal setting group and the *cold load pickup* setting group for user-selected circuit breaker protective relays and reclosers located in substations and reclosers located out on the distribution feeders.

Distributed Energy Resource Monitoring and Control

The DMS shall use available distributed energy resources (DERs), both customer-owned and utility company owned, to help control real and reactive power requirements on the distribution system. The DMS shall be able to request DG power factor modifications and remote generation disconnection. The DMS shall also monitor in real-time, actions taken by the Independent Power producers (IPP), such as verification that requested load reduction has actually taken place. The DMS shall also enable the utility to monitor the performance of customer owned power generators.

The DMS shall include facilities to enable the utility to incorporate IPPs into real-time generation dispatch and control. The DMS shall be able to use a customer’s DG unit to help control real or reactive power imbalance on a distribution circuit. The DMS (or AMI system) shall monitor energy flow at the metering point to determine customer response. The DMS shall be able to control generation MW/MX output using SCADA in a manual mode and perform power balancing and generation dispatch in an automatic mode. In manual mode, the dispatcher shall be able to specify amount of MW/MX and send that through SCADA; In automatic mode, generator control will be placed in AUTO, and the DMS application shall dispatch through SCADA.

The DMS shall include monitoring and control of temporarily isolated (*islanded*) portions of the distribution system powered by distributed generating resources owned by IPPs and the utility company. This is commonly referred to as *microgrid* operation, which is the intentional islanding of selected portions of the distribution system to enhance reliability and provide high power quality to customers with sensitive loads. All applications including online power flow shall be capable of solving the islands energized by generators provided that islands are feasible (that is there is enough generation to supply loads and losses in those islands).

Emergency Load Shedding

The DMS shall include an Emergency Load Shedding (ELS) function that shall be executed in real time on request. This function shall be synchronized with load shedding functions that are executed in EMS (under frequency, under voltage load shedding). The objective of ELS is to minimize the manual effort that is required to shed a specified amount of load and restore the previously shed load when the initiating problem is corrected. The user shall be able to initiate load shedding only for loads that are included in the user's assigned AOR.

When emergency load shedding is required, the user will activate the ELS function and enter the amount of load to be shed. The ELS shall then determine which switching devices to operate to accomplish the load shedding objective. ELS shall allow the user to shed load using the following load shed facilities.

Integration with External Systems

The DMS shall interface with numerous external systems that have been implemented by the electric utility or are planned for implementation in the near future. This section identifies the functional requirements for the interfaces between DMS and external systems. This section identifies the purpose and objectives for each interface, required data flows between systems, and other relevant details about the interface.

Geographic Information System (GIS)

This interface shall enable the DMS to obtain information from the Geographic Information System (GIS) for building the static network connectivity model, displays, and electrical model used by the distribution application functions. This interface shall streamline the initial static network connectivity model and display building process and simplify the creation of the electrical model used by the DMS applications. The DMS-GIS interface shall also simplify future maintenance of static network connectivity model, electrical model, and displays.

The GIS shall provide up-to-date information about distribution assets that is needed to build and maintain the feeder model used by the advanced DMS distribution applications. The GIS shall supply up to date connectivity information for the distribution feeders. Physical details about the distribution feeders (such as the arrangement of conductors) are not currently available in the GIS. Therefore, the DMS shall calculate the electrical parameters (resistance, reactance, and so forth) required by the feeder model using conductor arrangement information supplied by GIS. Some of the distribution asset information not available in GIS, (for example, distribution service transformer name plate data), shall be entered manually by the user. The DMS shall include convenient facilities to enable utility personnel to enter additional data needed to build the accurate model of distribution system.

The GIS shall supply information needed to construct geographically correct DMS displays (feeder maps), for each feeder: its related set of switchgear one-line schematics, that include utility company assets, as well as internal details the reference landbase and structures. The DMS shall include facilities for converting geographic displays to schematic displays and facilities for accepting one-line schematic displays. The DMS shall obtain reference landbase from the GIS.

Physical information and connectivity of distribution substation assets required by the feeder model may not be included in GIS and may need to be obtained from the EMS and other external systems. Some of the substation equipment data and topology information will need to be entered manually by the utility company. The DMS shall include a conversion tool or other convenient facilities to enable the utility company personnel to construct the substation portion of the distribution models as well as substation displays. The conversion tool shall enable automatic conversion of single-phase substation model representation that is exported from EMS (or other system) into a three-phase substation model representation required for DMS.

The GIS shall update the DMS on a daily basis or more frequently. Updates shall include incremental updates of as-built changes and drafting/corrections identified by circuit/feeder. Suitable facilities shall be provided on the Quality Assurance (QA) system to verify and validate the changes prior to incorporating the changes into the production system to prevent corrupting the DMS model. Visibility of daily pending Plant alterations (PAs) developed through the graphical work design capability of the GIS shall also be included. The DMS shall provide visibility of pending PA's with redline functions

It shall be possible to perform incremental updates to the DMS model via the GIS interface. That is, it shall not be necessary to rebuild the entire model for every update.

Advanced Metering Infrastructure

Voltage measurements shall be acquired via the AMI system from selected AMI meters installed at customer premises near feeder extremities. These voltage readings shall provide feedback to the VVO application to ensure that voltage at the customer locations are within specified limits.

Outage Management System

The DMS shall interface with the electric utility's Outage Management System (OMS). The interface to OMS shall be used for real time data capture of partial restorations, device status changes, and temporary device additions and deletions (jumpers and line cuts). The DMS must be able to send the temporary device additions and deletions to the OMS in such a fashion that a human operator can apply the changes that were made to the DMS. OMS should send back the predicted fault-interrupting device.

The DMS shall support sending device operations to the OMS. At a minimum, the DMS interface to OMS shall be used to pass the following data elements to OMS:

- Device status changes
- Momentary device status changes
- Notification of temporary device additions and deletions (jumpers, cuts, ties)

Field personnel will report blown lateral fuses or where they've had to manually operate devices to the OMS operator. The planned OMS interface shall pass manually operated device status changes to DMS.

The DMS shall support sending model edit notifications to the OMS for line cuts and jumpers. In addition, the DMS shall obtain messages from the OMS system for manual device operations.

Energy Management System

This interface shall enable the DMS to obtain substation measurements and execute control actions for substation equipment. The DMS-EMS interface shall enable the DMS to transfer to the EMS user- selected distribution quantities available in the DMS (including measured and calculated points) to the EMS to improve state estimation.

DMS shall obtain voltages and phase angles from EMS state estimator to be used as injections in the DMS network model. EMS shall transfer voltages and phase angles at injection buses (high voltage transformer buses at distribution substations) as well as equivalent network impedances as seen from those buses.

Corporate Data Historian

DMS will require an interface with the corporate data historian that pushes device status and analog readings from substation equipment tied to EMS/SCADA into the DMS.

5
CONVERGENCE OF OPERATIONS TECHNOLOGY WITH INFORMATION TECHNOLOGY

Computer based systems that are used for continuous, real-time monitoring and control of the energized power equipment, such as the distribution Supervisory Control and Data Acquisition (SCADA) system, are commonly referred to as Operations Technology (OT) systems. OT systems have been operated and maintained by control room operating personnel and support staff, and have traditionally been kept physically separate from other corporate computing systems. Corporate computer-based systems such as the Geographic Information System (GIS), Customer Information System (CIS), and Enterprise Resource Planning (ERP), which are primarily used to maintain records of network assets and static network models; customer and billing information; accounting, and human resources, and so forth, have traditionally been referred to as Information Technology (IT) systems.

OT focuses on real-time system monitoring and control. There may be a brief period of time when a switching device status is indeterminate, for example, after an operation command is issued and before the device status is confirmed. On the other hand, IT focuses a lot on transaction integrity. For example, a banking transaction on Automated Teller Machine (ATM) can succeed or fail; there is no other state. Another operation on the ATM or the same bank account is not allowed until the state is known. Similarly, a database transaction must succeed or fail, no other transaction is allowed until the state is confirmed before another transaction to protect the database’s integrity.

The practice of keeping OT systems separate from IT systems has changed considerably in recent years. Firstly, there are more data interfaces between OT and IT systems. For example, DMS applications such as online power flow; Volt/VAR Optimization (VVO); Fault Location, Isolation and Service Restoration (FLISR) require regular, daily or even near real-time updates to the electric distribution network model with as-engineered and as-built data from GIS. FLISR can benefit from outage events from Advanced Metering Infrastructure (AMI). VVO can benefit from voltage measurements from AMI meters. DMS load allocation or state estimation can benefit from meter load data maintained in Meter Data Management (MDMS). Conversely, asset management applications that are usually maintained by IT such as Work Management System (WMS) and Computerized Maintenance Management System (CMMS) can benefit from the distribution system and device operation and loading histories that are logged in DMS. Data corrections and changes to normal operating states such as energization of a new feeder extension need to be coordinated between DMS and GIS. The increased integration between IT and OT systems and applications has drawn IT and OT staffs working together more.

Secondly, as part of the general trend of the aging workforce in American utilities and specifically in the system control centers, specialized and dedicated OT staffs which need skill-sets in both IT and power engineering and operation applications are becoming scarcer. On the other hand, general IT staffs are much more available, as universities continue to produce many more graduates in computer science and information management. So, there is upward pressure of utilizing corporate IT staffs to pick up as much OT workload as possible while also operating and maintaining the corporate IT systems.

Last but not least, utilities continually face the challenge of reducing their operating costs further. Sharing resources between IT and OT is considered as a potential opportunity of cost reduction.

With increased collaboration of IT and OT for reasons discussed above, there are potential benefits in harmonizing their standards, guidelines and practices developed in the IT industry. This report explores these potential benefits by examining the key similarities and synergies as well as key differences between IT and OT practices for the design, implementation, operation and maintenance of computer based systems used in distribution control centers. The objectives of the report include bridging knowledge gaps between persons whose background is primarily in electric distribution system operations and persons with background in IT, identifying areas where IT practices make sense in the operations environment and areas where there is not a good fit.

Last but not least, utilities continually face the challenge of reducing their operating costs further. Sharing resources between IT and OT is considered as a potential opportunity of cost reduction.

Objectives

With increased collaboration of IT and OT for the reasons discussed above, there are potential benefits in harmonizing their standards, guidelines and practices developed in the IT industry. This report explores these potential benefits by examining the key similarities and synergies as well as key differences between IT and OT practices for the design, implementation, operation and maintenance of computer based systems used in distribution control centers. The objectives of the report include bridging knowledge gaps between persons whose background is primarily in electric distribution system operations and persons with background in IT, identifying areas where IT practices make sense in the operations environment and areas where there is not a good fit.

IT and OT Contrast

Table 5-1 summaries key elements of IT and OT and their contrasts.

Table 5-1
Summary of IT and OT Characteristics

	Information Technology	Operation Technology
Discipline, Approach and Methodology Emphases	• System maintainability and sustainment • Product life cycle • Standardization • Cyber security • Effective utilization of hardware, software, and communication facilities	• Safety (workforce and general public) • Protection of energized assets and supporting facilities • Physical security • Performance of power system (efficiency, reliability, overall power quality) • Effective utilization of power system assets
System Characteristics	• Some level of latency permitted (Day after, week after, monthly, annual analysis) • No direct control of power apparatus • Very high volume, file oriented information or transaction data • Expected system lifetime 5 to 7 years	• Minimal latency – real time and near real time monitoring and analysis • Direct control of power system assets • Time series data • Expected lifetime 15 + years for field equipment • Expected system lifetime 7+ years
Application	General industry standards and protocols for data management, system administration, human interface, business applications, transaction processing.	Power system operations specific standards and protocols for device-to-device communication, device-to-server communication, grid monitoring, control, and protection.
Environment	Corporate data center, offices, server rooms	Substations, field devices, OT database and application servers mostly in control centers.
Network	Corporate network	Dedicated data network for control center, network monitoring, protection and control.
Data Source	Human entry, other IT or OT systems	Sensors, IEDs, field devices (RTUs, PLCs, and so forth), operators, other OT systems.
Information Output	Reports, analyses, display presentations	Control actions, alarms, operating logs, tabular, schematic and geographic displays.

System Integration for Monitoring and Control

This section provides guidance – through exploring the differences, similarities, and synergies of IT and OT – as to what extent IT integration techniques, such as Service Oriented Architecture (SOA) implementations with Enterprise Service Bus (ESB), be used for real-time or near real time monitoring and control of the electric power distribution system. A key question is whether ESB and other system integration technologies commonly used in IT would provide the same performance and functionality as traditional SCADA communication protocols (for example, DNP), substation communications and SA services standards (for example, IEC 61850), and protocols for inter-control room application interfaces (for example, ICCP).

From the engineering and design point of view, IT has developed common technologies across applications with maintainability and extensibility driven, such as Open Database Connection (ODBC) for database access, Enterprise Service Bus (ESB) for implementing Service Oriented Architecture (SOA) to enable multi-system data sharing, web-based user interface, enterprise-wide IT security services for authentication and authorization, and so forth SOA/ESB in particular improves information flow, and hence greater benefits, across the utility enterprise by making it easier and quicker to distribute data of an application for further processing, analysis, and presentation by other applications. (*See Appendix A for more discussion on SOA/ESB.*)

On the other hand, mostly due to legacy systems and past practices, OT tends to use point-to-point system interfaces to ensure security as well as to maximize performance. For example, DNP3 and ICCP are designed for point-to-point interfaces rather than for implementation with ESB. Development of the Common Information Model (CIM) based on the IEC 61968 and IEC 61970 sets of standards facilitates SOA/ESB implementation. Still, when it comes to more real-time data interface requirements, OT still uses point-to-point interfaces to ensure performance, probably due to a lack of confidence that SOA/ESB can provide similar performance. A case in point is the integration of AMI/MDM and DMS/OMS. A good number of utilities choose to use point-to-point interface for AMI outage events, which are event driven and more real-time than other AMI/MDM data such as load profiles – even though IEC 61978 supports the outage event interfaces. Another example is that many implementations of SCADA to DMS/OMS interface still use ICCP instead of IEC 61978.

Recommendation: SOA/ESB is used in large financial, military and aviation applications that have much demand on secure and real-time data and transactions as electric power system control. Due to advances in ESB technology as well as increasingly powerful computers and high-speed data communications, the added overhead of routing data through the ESB is should not noticeably affect performance of distribution monitoring and control functions. Furthermore, the CIM established under IEC-61968/IEC-61970 already enables DMS integration using the SOA/ESB approach. Hence, OT should trend towards the SOA/ESB direction in general.

From the software development and system implementation point of view, over the years the IT industry has developed comprehensive application development methodologies and software engineering tools. IT community becomes a structured, process-oriented, society. On the other hand, OT developers are typically *goal-oriented* engineers who focus more on performance of the specific project rather than long-term benefits across information systems of other departments. For instance, when IT integrates GIS and WMS, they will take more time to increase the possibility of reuse for future ERP interfaces and asset management applications. On the other hand, when OT integrates DMS with GIS, they mainly want to implement the interface quickly and efficiently and make sure that the resulting GIS and DMS interface will perform well. Less attention will be given to how the GIS-DMS interface may be leveraged to also support distribution system planning and asset management applications.

Recommendation: OT often perceives IT as not being responsive – because they architect any project or change request "to death" before they do anything. IT often perceives OT as "cowboys" who implement software systems in an ad-hoc manner. In truth, both IT and OT approaches, and perceptions, have some merits. A happy medium should be established through a governance model (a set of guidelines and processes) that has buy-ins from both IT and OT. The governance model eliminates debates with every project that comes up in the future, saving valuable time and efforts.

Furthermore, *sharing*, is a general theme in system architecture design and implementation – not only data sharing, but also hardware sharing. Cloud or virtual computer environments are examples. Due to concerns over cyber security – or lack of confidence that cloud and virtual environments can provide similar level of security and performance, OT tends to use *dedicated* servers, database, and data network infrastructures (LAN/WAN).

Recommendation: Cyber security, particularly in this era of higher standards in NERC CIP guidelines, is a very serious matter. More operation history of security and performance cloud computing and virtual computer servers is needed before the system control center would host any NERC CIP applications and data in the cloud/virtual environment.

From the system maintenance and support point of view, IT industry has developed generic experts in each technical domain – such as software, hardware, and communication network. System support personnel are often interchangeable within each domain. On the other hand, in the OT community, specialists are often needed for each information system (for example, SCADA/DMS, EMS, SA/DA, protection and control devices). Most SCADA systems have a vendor-specific real-time database and vendor-specific data management tools, requiring specialists to maintain and support the system. This has led to a separate organization and staff for OT at most utilities. On the other hand, most DMS/SCADA systems today run on common computer server platforms and workstations (for example, IBM and HP servers with Unix or Linux operating systems, and Intel MS-Windows based workstations). The DMS/SCADA systems also support archive of historical data (operations, events, alarms, and so forth) in an open, commonly available database management system such as Oracle and Microsoft SQL-Server. These historians support Open Database Connectivity (ODBC) – a common IT standard, and hence they can be supported by Database Administers from corporate IT.

Recommendation: A dedicated group of OT specialists is still needed to support the real-time systems and applications such as DMS/SCADA. Nevertheless, a lot of the infrastructure support such as computer servers, workstations, historian databases, and so forth can be supported with shared IT resources to improve synergy and cost efficiencies in the utility corporation. Service Level Agreements (SLA) should be considered to communicate the business requirements and identify which area will be responsible to support each system and/or infrastructure.

Another area of differences in the ongoing operation and maintenance of IT and OT systems is that historically many OT systems such as SCADA are heavily *customized*. This makes OT system upgrades much more difficult and costly. On the other hand, IT systems tend to be *configured* using vendor provided and often upward compatible tool sets, making it easier and more cost effective to upgrade corporate IT systems. The implementation in ESB enabled SOA also facilitates modularized upgrades (that is upgrading certain application modules rather than replacing the entire system.)

Recommendation: Some OT organizations already use SOA/ESB for integration as explained above and to stick with "Commercial Products Off the Shelf" as possible. Hence, overtime, as customized legacy OT systems are replaced, OT upgrades will inherently get to the same level of effectiveness as IT.

Table 5-2 summarizes the differences, similarities and synergies of IT and OT in the integration of monitoring and control systems.

Table 5-2
System Integration for Monitoring and Control – IT and OT Comparisons

	Differences	Similarities	Synergies
Engineering and Design	Process: IT designs tends take the time needed to ensure maintainability, upgradeability, and extensibility; to assess impacts on other IT systems. OT tends to focus more on achieving project performance as fast as possible. System Integration: OT uses utility specific integration standards, for example, IEC 61968/IEC 61970 (CIM) or MultiSpeak, ICCP, and so forth IT uses general standards (for example, ODBC for data base access, Common Object Request Broker Architecture (CORBA) for object oriented programming). The trend of GIS interface is via a CIM adaptor. Communications/messaging: OT uses power system specific protocols (DNP3, IEC 61850). IT uses general standards such as SMS for short messages, MMS for multimedia messages… OT integration historically has been mostly point to point and point to multipoint (MAS). Security: OT systems historically tend to rely more on security provisions built into the protocol standards. IT would also rely on common security services such as IPS and IDS for example. Architecture design: OT is more system performance and availability focus; databases are often de-normalized and based on proprietary real-time databases for these reasons. In addition, IT will stress maintainability and extensibility in database design and use computer hardware to improve performance and availability (for example, more and faster CPU, more memory, cluster and redundant servers, SAN disk storage)	The CIM concept is the same. XML is a common language used by both OT and IT. Both OT and IT are trending towards service level integration via SOA/ESB. For security, OT is trending towards using security services such as IPS and IDS, encryption and key management to strengthen security, as has been used in IT. OT is increasingly using computer hardware solutions to achieve the required performance and availability, instead of using proprietary real-time database and de-normalized database designs.	Find a balance of response time vs. discipline that would be acceptable to OT. Both IT and OT want to achieve project goals within budget and schedule. IT processes can often be *negotiated* in open discussions. Shared security services. Infrastructure design (for example, database replication and disaster recovery).

Table 5-2 (continued)
System Integration for Monitoring and Control – IT and OT Comparisons

	Differences	Similarities	Synergies
Development/ Build	OT will do it quick; it is more result oriented. "Why do we have to wait for enterprise architecture, ESB to be developed?" Time to benefits is of essence. IT tends to be more methodology and process focus. It will spend more time to make sure the architecture and infrastructure is built. Acceptance tests. OT will do more ad hoc testing and follow end-to-end integration testing. IT will follow structured test plans and test methodology more, and do more watermarks and boundary testing. So, IT appears to be slow to OT folks. And OT appears to be *cowboys* to IT folks. Servers: OT systems tend to be dedicated (for example, FEP server, application server, simulation server, ICCP server, database server) IT trend is to put the servers in the *cloud* or in a virtual environment.	Both IT and OT are concerned about performance and availability. Both IT and OT are concerned about security. Both will restrict access to the production environments. OT is trending toward using computer hardware solutions for achieving performance and availability targets instead of customized solutions as used for historical EMS implementations.	Find a balance of response time vs. discipline that would be acceptable to OT. Both IT and OT want to achieve project goals within budget and schedule. IT processes can often be *negotiated* in open discussions. Implementing the necessary computer and networking infrastructures. Implementing the necessary data storage and DBMS.
Maintenance and Support	OT support tends to be application focus (for example, SCADA, EMS, DMS) IT tends to be platform and infrastructure focus (for example, data base admin, LINUX, Web services). OT support is typically provided by specialist; IT by generalist. Change management: OT wants to make changes fast, bug fixes or enhancement requests. IT wants to go through *the process* to make sure approval is obtained from all stakeholders and to make sure the changes have no unintended impacts, and so forth So, OT appears to be slow to IT.	OT and IT both need to support applications as well as platform and infrastructure; for example, OT for DMS applications as well as servers and network, IT for billing applications as well as servers and network. Both OT and IT have either formal or informal service level agreements or targets.	Use IT more for infrastructure and platform support (for example, database tuning), freeing up time for the OT specialists to focus more on operational benefits. IT and OT can often *negotiate* on the time needed for a change request when both sides discuss and understand each other's concerns. Vendor contract management.

Data Management

This section describes the data management lessons-learned from the IT world, including technologies and methods that can be applied to manage the potential *data tsunami* that is facing control room operators with the deployment of more and more Smart Grid Intelligent Electronic Devices (IED).

One of today's challenges is managing the tsunami of data. With Smart Grid, this has become a challenge for many IT and OT departments. Some of the key differences between IT and OT data management include:

- OT real-time data is typically stored in propriety databases. IT data is stored in standard data base management systems (DBMS), including real-time transaction data.
- OT data contains real-time measurements, streaming telemetry data, messages and alarms. IT data contains financial, personal and asset information, where transaction integrity is of utmost importance.
- OT data can be very granular (on demand, minute, 15 minute, hourly, and so forth) IT data is stored daily and summarized on a monthly, quarterly and annual basis.
- OT data is typically exported to other systems for studies through an Extract, Transform, and Load (ETL) process. IT data is interfaced with other systems at the database level or on transaction basis.

There are also some overarching similarities between the data management of IT and OT systems. These include:

- Data management is important to both IT and OT departments and their users. Data is critical for the organization to support business processes and make key business decisions.
- Data quality and information protection are important to both IT and OT.
- Both OT and IT are increasing the use of data analytics/business analytics to improve the value of information.
- Database backup and restoration, disaster recovery and failover support.
- Databases and spreadsheets are used to manage and filter large amounts of data.
- Real time data is used to support key operational business processes including system monitoring, outage management, crew dispatching, workforce management, communication network management, and so forth.

Because of these similarities, significant synergies can be gained between the IT and OT departments to support their respective data management requirements and goals. The synergies include:

- Business Intelligence and data analytics tools including integration of IT and OT systems to enable enterprise wide BI – IT and OT should work together to exploit opportunities to leverage existing or implement new data warehouses and data analytic tools that can be used corporately. More utilities are storing, managing and mining data for business value, safety, power quality, asset management and customer behavior. This data is used to for business, asset and capital optimization.

- Database and data warehouse implementation and maintenance – utilize IT resources specifically trained as Database Administrator (DBA) or in data modeling to assist, support or maintain OT databases.
- Elimination of duplicate data entry between IT and OT system users – the opportunity to leverage other systems and their data is important to avoid data duplication and maintenance. Organizations should identify the system of record for asset and operational data.
- Data governance, policies and processes, including for example data security/information protection – with IT departments supporting many of the enterprise systems, IT departments have typically developed many data governance and data security policies and procedures. OT departments may want to leverage and implement these policies and procedures. Corporately, there are advantages to consolidate data management policies and procedures and have one department responsible for administering them. On the other hand, it is important for IT to engage OT when developing policies and procedure to understand their requirements. The other advantages include consolidating maintenance and support for the data warehouse, tools and the administration to reduce the overall operation cost of the utility.

System Documentation

This section describes proven IT methods for system software documentation. In particular, it addresses the question of whether UML diagrams, use cases, and other system documentation practices used in an IT environment would work just as effectively in the development of applications in the control room operating environment.

Both IT and OT organizations understand the importance of system documentation. However, IT often has structured documentation practices. IT documentation focuses on system administration, system design and development such as system design and interface control documents, database description such as database schema. OT's documentation is less structured but often written in a language that operational users can easily understand. OT strives for better user manuals and application guides, and OT administrators would rely more on vendor training and support for system and database admin.

Both want system and user documentation albeit in different level of details and styles. The following examine areas of documentation that are often misunderstood between IT and OT but that offer improvement opportunities by harmonizing the IT and OT practices. ***The IT and OT practices are complementary to each other.***

System Architecture

IT often follows a structured process of developing and documenting the system architecture, including the following architecture diagrams and associated descriptions for example:

- Business architecture – depicting the business unit functions and interactions targeted by the information system(s). The business architecture provides the reason for the information system(s) – the *why*.
- Information system architecture – depicting what information system(s) are involved (existing, under-development, and the systems implemented in the proposed project) and the data flows among them. The information system architecture provides the context and scope of the project – the *what*.
- Application architecture – depicting how the applications of the proposed information system would interact with existing and systems under development through other initiatives. The requirements of the interfaces are described, including invocation (for example, event driven, on demand, scheduled batch processing), interface method and protocol (for example, file transfer, direct database access, messaging, web services), and frequency (estimated number of data transactions per day/hour/minute). The application architecture document outlines the *how*.
- Technical architecture – depicting the software and hardware architectures of the project implementation, including computing platforms, software module product names and versions, the number of servers and their locations, data network infrastructure and locations of any firewalls, and so forth. The technical architecture explains the *with what* of the project implementation.
- OT specifies the functional requirements and technical nonfunctional requirements (for example, scalability, availability, and security), system integration requirements, number of users and other dimensional parameters – in plain English – and then tries to go straight to the technical architecture with inputs from the selected software product vendor.

OT can get to the *end game* of the project faster. IT takes a more holistic approach, which takes more time.

Recommendation: Both approaches have merit. If IT is engaged from the functional and nonfunctional requirement specification stage, the business, information system, and application architectures can be developed rather quickly and effectively in parallel with the requirement specification efforts. These architectures will also help the prospective OT system vendors understand the requirements and develop the technical architecture more effectively.

Use Cases and Business Process Modeling

Both IT and OT documents use cases in plain English. However, IT follows a more structured process and use case templates to make sure that all alternative responses in a use case are captured, including exception and error handling. The structured use cases can also be helpful when developing test plans and training materials. And, IT often does not stop there. IT would go on and translate the use cases in Unified modeling language (UML) and UML class diagrams to document the objects, their attributes, methods and relationship with other objects. The structured UML can help minimize misunderstandings between the developer and end users, which may result in possible rework or not meeting the business requirements. Data models and object-oriented computer programs can also be developed from the UML with available software engineering tools.

Besides use cases, both IT and OT have been documenting business processes and workflows in swim lane diagrams. IT also use sequence diagrams to describe data flow details based on the business process model. These can be used as part of the change management plan when identifying the gaps from the *as is* to the *to be* business process.

Recommendation: OT should continue to develop and document use cases, following the use case structure and template proven in IT in multiple industries, to improve change management, training and testing. However, most of the time and the ongoing trend is that utilities would buy commercially available products, as much off-the-shelf as possible, instead of OT doing its own development. Since UML is mainly used to facility software development, UML is often not necessary for OT system users. An exception may be sequence diagrams, which are easy to understand (almost like plain English) and their review (if not development) by OT will help OT users make sure their business processes are modeled and subsequently implemented correctly. As more IT and OT system integration is needed (see BI discussion above), these documentation techniques such as use cases and sequence diagrams can be very useful in improving consistency and understanding between IT and OT.

Documentation Change Control Process

For the sake of expediency in implementing application software and hardware changes, there are often inconsistencies between the system and software configurations and their documentation. Such inconsistencies may cause ineffective support and overtime future system changes – particularly when a new OT support staff is involved.

Due to regulatory requirements of Sarbanes Oxley, IT departments have implemented strict change control processes and governance procedures in place for all IT systems especially those supporting the financial, customer and employee information. OT can leverage these existing processes and procedures.

However, there may be reasons and justifications why OT cannot follow all the procedures due to the priority of supporting mission critical applications in the control center. For example, a critical change to an OT system cannot wait for the formal change control and approval process and corresponding documentation changes. In this situation, documentation will follow the change implementation instead of preceding or in parallel with programming or hardware/software configuration changes. The analogy is normal operation versus storm restoration. In normal condition, the utility would want system changes to be designed, documented and approved before the changed are made. All asset changes (for example, transformer replacement) due to an outage would be documented immediately after the replacement; but the system configuration/asset changes made in the course of a storm restoration effort could be documented after the storm.

System Security

Guarding computer-based systems from unauthorized access by internal and external intruders is a matter of keen interest to both IT and OT personnel.

Key questions to answer when considering the IT and OT infrastructures include:

- What new security challenges are imposed when IT and OT systems are interfaced and integrated?
- Are industry IT security solutions suitable for addressing Critical Infrastructure Protection (CIP) standards?

While IT and OT has its own goals and objectives for cyber security strategy, they both have a common interest of data confidentiality, integrity, and availability.

Confidentiality attempts to prevent the intentional or accidental release or disclosure of information to an unauthorized party. Loss of confidentiality can happen in several ways in a communications network, but the most common is some form of tapping of the communications medium. Lack of confidentiality can be mitigated using encryption or access rights.

Integrity ensures that the information transmitted through the network is the correct information: it has not been modified, either by an unauthorized process or person, or has not undergone an unauthorized modification by an authorized process or person. Integrity also ensures that the data are self-consistent, that is, data corresponding to an entity is consistent with the data represented by all of its sub-entities. Integrity can be accomplished using authentication or multiple data sources.

Availability ensures that reliable and timely access to data and network resources is made to authorized personnel and processes. Available networks are up and running and performing within their designated design parameters. Redundant network paths and technical robustness of the implementation can mitigate lack of availability.

Security Challenges of Integrating IT and OT Systems

Perhaps a key difference in IT and OT security requirements is the need for the OT infrastructure to follow applicable NERC CIP requirements. Not all OT networks may be required for NERC CIP conformance, mainly those certain critical assets in the utility company that would be subject to NERC CIP. Under current NERC CIP rules, these assets require special considerations if they communicate via *routable* protocols. Routable protocols are defined as those that are based on network addressing, such as the IP protocol. In contrast, Ethernet is based on device addresses, and would not be a routable protocol. (*See the Terms and Definitions, section 4 for the explanation of the differences between Ethernet, IP, and TCP/UDP*.) If a routable protocol connects to the NERC CIP qualified asset, an electronic security perimeter must be established to protect the asset. The minimum implementation could consist of a router with appropriate access lists implemented. The access lists should be granular enough to filter on initiating IP address, destination IP address, port number, and initiation direction. In addition, logging should be enabled to provide an audit trail of all traffic (or at least all unknown and blocked traffic) for further analysis and inspection. However, the logging function is normally a feature of firewall-class devices rather than routers. Thus, NERC CIP requirements would not be totally far removed from what available IT assets can provide.

Historically, IT and OT networks have been separate and independent, and each had their own cyber security approach. OT networks were typically point to point time-division multiplex (TDM), supporting serial protocols such as DNP3. IT networks were more IP based and routable, having connections to untrusted networks such as the Internet. Now, technologies are available in the industry to support more of a converged network providing a common platform (and more cost-effective operation) to support IP, Ethernet, TDM, and so forth but with a capability to segment data within the platform.

Recommendation: The most common way to do combine IT and OT networks while ensuring security is to implement the Virtual LAN (VLAN), allowing independent performance parameters to be established for each data type, as well as establishing a level of protection and security for each data type. By circumstance, the IT network may fall into supporting NERC CIP requirements just because it has OT data using the IT WAN as a transport.

Overall, while security challenges may differ in the IT and OT environment, technology exists to support common goals of confidentiality, integrity, and availability.

Suitability of IT Security Solutions for Addressing CIP Standards

As discussed above, considerations for the routable protocol in the OT environment drives the OT network architecture to look more like an IT environment. NERC Critical Infrastructure Protection (CIP) has driven OT to be more structured with its procedures and processes, many of which are consistent with IT practices. However, the OT network is more *closed* than the IT network, limiting access to any network that has external connections. The use of firewalls and protected zones (DMZs) allows the isolation needed to protect operational data from direct access with the outside world. The firewall is a valuable tool for protection of the IT network as well.

In the past, the OT point-to-point networks have had limited considerations for security, as well as dial-up remote access networks, who could use them, and what access rights they had. At best, there may have been a single password to access equipment, or a default password that was never changed. In the IT environment, there are typically rules and procedures for access and password management and how often they are changed, as well as definition of levels of access rights.

Recommendation: The IT process and procedure applied to the OT environment is beneficial since NERC CIP requires this type of structured process and administration.

Table 5-3 summarizes the key differences, similarities, and synergies to consider between IT and OT.

Table 5-3
IT and OT Cyber Security Comparisons

	Differences	Similarities	Synergies
Engineering and Design	NERC/CIP implementation requirements for OT vs. IT industry security standards. OT requirements of isolation and protection of real-time mission critical data. OT security considerations that need to be supported in legacy technology (such as remote access requirements).	Security goals of data confidentiality, integrity, and availability. Requirements for disaster recovery.	Common security architectures that can support IT and OT. NERC CIP is driving OT to be more structured in procedures, which is consistent with how IT operates.
Development/ Build	Same as above OT consideration for routable protocol.	Same as above Defense in depth and layered security architecture.	Same as above. NERC/CIP can be followed as prudent security practice.
Maintenance and Support	Applications security requirements (that is SCADA vs. email).	Documentation of Procedures and processes.	Resources with knowledge of overall security requirements.

Required Skill Sets and Training

This section discusses the required skill sets and training for OT system development, maintenance and support. Persons that design, build, and maintain IT systems may be computer science professionals with minimal background in electric power system design and operation. This raises the question as to whether IT personnel possess enough background in electric power system design and operations to support real-time monitoring and control applications. Conversely, do power system operators, engineers, and control room technicians have enough knowledge about IT systems and technologies to effectively use these systems in a control room environment? What new skill sets and training are needed to bridge the knowledge gaps between IT and OT personnel? What synergies among IT and OT resources can be leveraged?

IT and OT personnel typically have different educational backgrounds and have different work experiences. Some of the key differences between IT and OT's skill sets and training include:

- OT personnel usually have an engineering background and less formal IT training than the corporate IT staff. They typically receive very specific IT and programming training. They are trained to use and support very specific operational systems (for example, SCADA, DMS).
- IT personnel have a Computer Science or Information Management background but often have no utility specific experience or training, particularly in control room operations. They are typically trained to use a wide range of programming languages as part of their education.

They support broader, enterprise systems. For specific IT enterprise functions, IT personnel will receive specialized training (that is computer languages, network, database, security, and infrastructure.)

There are also some similarities between the skill sets and training of IT and OT personnel. These include:

- OT personnel receive *on the job* IT training, whereas IT personnel receive *on the job* utility training.
- Design and justify projects prior to building.
- Manage a wide range of projects.
- Provide on call support to end users (during and after hours).
- Provide ongoing system maintenance/upgrades (hardware, software).

On the job training is common in both IT and OT departments. This is especially common for IT departments supporting OT systems as this experience can only be gained from working with other utilities or companies in the energy industry. There are more opportunities to get enterprise system experience within other industries.

It is common practice for both IT and OT departments to design and justify projects to the larger organization. Both departments manage large capital and maintenance budgets. Projects are typically prioritized on ROI, asset life, reliability, minimized maintenance costs, meeting business goals/strategy, and so forth

Due to the nature of the systems both IT and OT departments support, on call support is required during and after hours. Also, support for ongoing system maintenance and upgrades are essential to keeping systems operational long term.

There are synergies that can be gained between the IT and OT departments by utilizing their skill sets and training. The synergies include:

- Leverage IT's business analysis and data architecture experience
- Leverage IT's support of the enterprise infrastructure (hardware, database, network, security)
- Leverage IT's existing on call support processes and service level agreements (that is Helpdesk)
- Leverage IT's system development life cycle (SDLC) process and standards
- Leverage OT's utility experience in designing enterprise systems for integration
- Leverage or consolidate IT and OT's Project Management processes, standards and prioritization methods
- Business analytics and the data is needed to track field assets
- Integrated network operations center (INOC)

Leveraging IT's experience and knowledge in supporting enterprise infrastructure, on call support, business analysis, data architecture, and SDLC processes and standards can reduce costs and consolidate business functions. It allows areas to focus on their key area of responsibility.

There may be some areas where it makes sense to consolidate due to resource and budget constraints. At most, it may be as simple as IT communicating the services they can provide, at what level and cost.

Leveraging OT's experience and knowledge can also help IT be more successful when integrating enterprise systems with OT systems. This can be achieved by IT working in the same area as OT or jointly working on IT systems.

Both IT and OT manage projects. There may be opportunities to consolidate the project management processes, standards and prioritization methods between the areas. For example, how does a line rebuild compare to an ERP implementation? Do OT projects need the same IT PM governance and metrics? These are just a couple of questions to consider.

IT and OT need the data and business analytics tools to proactively track field assets. OMS systems can use data from SCADA, AMI, and GIS to analyze outages and improve outage response time. Asset management systems can use AMI and transformer load data to proactively identity field assets requiring maintenance or early replacement. The data and business analytic tools allow organizations to more efficiently spend capital funds and increase reliability.

With Smart Grid, both IT and OT departments are responsible for monitoring more components. This includes networks, servers, storage, collectors, sensors, and meters and utility data center systems (MDMS and DMS). Many utilities are considering an integrated network operations center (INOC) to monitor and manage their Smart Grid and AMI infrastructure and the communications network. This consolidation allows for more efficient processes and increased skill sets of the operations center personnel. It also facilitates the need for more automation for increased productivity.

Organizations should at least consider the above to determine if these are legitimate opportunities. Even if there is no opportunity, it begins to open up the lines of communications and ultimately bring down the silos between the IT and OT departments.

Table 5-4 summarizes the differences, similarities, and synergies of IT and OT skill set and training requirements.

Table 5-4
IT and OT Skill Set and Training Comparisons

	Differences	Similarities	Synergies
Engineering and Design	• OT-Engineering background with limited IT training • OT-typically self taught or very specific IT and programming training • OT-Support and use very specific operational systems • IT-Computer Science and Business Analysis background • IT-Support broader, enterprise systems • IT-wide range of programming language training typically received from their education	• OT-*On the job* IT training • IT-*On the job* utility training • IT and OT must design and *justify* projects prior to building	• Leverage IT's business analysis and data architecture experience or obtain this skill set • Leverage OT's utility experience to assist in designing broader systems for integration and reuse or obtain this skill set • Leverage IT's SDLC process and standards • Business analytics is needed by both IT and OT to track field assets and it's data
Development/ Build	• OT-Engineering background with limited IT training • OT-typically self taught or very specific IT and programming training • OT-Support and use very specific operational systems • IT-Computer Science and Business Analysis background • IT-Support broader, enterprise systems • IT-wide range of programming language training typically received from their education	• OT-*on the job* IT training • IT-*on the job* utility training • IT and OT manage wide range of projects	• Leverage IT's business analysis and data architecture experience or obtain this skill set • Leverage OT's utility experience to assist in designing broader systems for integration and reuse or obtain this skill set • Leverage IT's SDLC process and standards • Leverage IT and OT's Project Management process, standards and prioritization methods • Business analytics is needed by both IT and OT to track field assets and it's data

Table 5-4 (continued)
IT and OT Skill Set and Training Comparisons

Maintenance and Support	• OT-Engineering background with limited IT training • OT-typically self taught or very specific IT and programming training • OT-Support and use very specific operational systems • IT-Computer Science and Business Analysis background • IT-Support broader, enterprise systems • IT-wide range of programming language training typically received from their education • IT-Specialized training to support enterprise technologies (computer languages, network, database, security, infrastructure)	• Provide on call support to end users (during and after hours) • Provide ongoing system maintenance/upgrades (hardware, software)	• Leverage IT's support of the enterprise infrastructure (hardware, database, network, security) • Leverage IT's change control procedures • Leverage existing on call support processes and service level agreements (that is Helpdesk) • Determine which area is best suited to support OT systems

DMS Architectural and Communication Issues

Some utilities are considering using a so-called *location agnostic* design in which DMS servers are installed at a location that is separate from the control center where operator consoles reside. What are the benefits and challenges of housing OT system servers in corporate IT data centers?

This section discusses differences, synergies, and challenges of data communications for OT (EMS/SCADA, DA) and IT (Corporate, AMI, and so forth). This section also identifies the differences, synergies, and challenges of mobile applications and communications for OT (for example, switch orders, emergency repair orders), and IT (for example, customer service orders, inspection and maintenance).

DMS Architecture

Utilities are facing increasing challenges to improve the efficiency, the performance and reliability of the power delivery and utilization. To address these challenges, there are significant evolutions of distribution automation, deployment of AMI, implementation of demand response (DR) programs, development of home area network (HAN), and large penetration of distributed energy resources (DER) that include small wind, solar, storage, plug-in electric vehicle (PEV), and so forth and possibly micro-grids. Distribution management functions are not only to operate the distribution system more efficiently, reliably, securely, but also to prepare utilities to be ready for potential integration of new loads (for example, PEVs, and new generation supplies, solar PVs, distributed generations). Advanced DMS shall provide operators of distribution systems with advanced monitoring and control capabilities, network analysis and optimization applications, and the decision-support tools to improve the system reliability and maximize the efficiency and performance of system operation. Examples of advanced DMS functions may include: Analytical Volt-VAR control and optimization (VVO), Fault Location, Isolation, and Service Restoration (FLISR), PEV charging management, DR management, and so forth

In order to overcome the complexity of these advanced DMS functions, given the challenges in distribution systems; localized analytics has become essential to handle the challenges presented by new loads and generations. The so-called *cluster manager* may have to be incorporated into the application algorithm design. This trend has posted possible changes in the traditional DMS architecture. The technologies of *location agnostic servers* presented in the IT industry are becoming attractive to OT community. Location agnostic design approach moves most of activities, messaging, and so forth to the server-side from client-side in order to eliminate the dependency of locations. Cloud computing is one example. It is a method of location agnosticism by provisioning computing resources, including both hardware and software, which relies on sharing those resources rather than using local servers or personal devices to handle applications.

While the location agnostic architecture brings in important benefits, it also introduces concerns. With such design architecture, it is not necessary if the advanced functions are located centralized at utility control centers, substations, or at the IED field devices. Very often, the advanced DMS application servers reside at data centers that are not together with the distribution operators' workstations. This introduces two major concerns on communication: (a) security and (b) speed performance.

Security

Technologies that combine state-of-the-art VPN, virtualization, multi level access control and data encryption techniques, have to be implemented. The application servers should also be protected against physical attack attempts, data reads from storage media and even against potential leakage by datacenter or administration personal.

Speed Performance

To achieve speed performance requirements for the advanced DMS, when the application servers are at data centers (or any other locations), a variety of connection methods should be considered to handle different use cases and processing scenarios. A seamless and high bandwidth access to the application servers becomes critical.

During the process of design and development of an advanced DMS system architecture, not only the interfaces with OMS, AMI, and so forth are important, but also the possibility of adopting location agnostic approach from IT should also be investigated.

Data Communications

Table 5-5 shows key differences, similarities, and synergies between the OT and IT in regards to data communications networks.

The benefits of deploying converged communications and supporting network connectivity, as well as state-of-the-art technology requires the design and implementation of a robust technology and control framework that includes technical, operational and management controls, and security policies, procedures and supporting processes. Enhancements to a utility's communications infrastructure support the two-way flow of both electric power and information between the electric power company and electricity consumer. Methods and capabilities addressing interoperability should be included. *Interoperability* is generally defined as the capability of two or more networks, systems, devices, applications, or components to share and readily use information securely and effectively with little or no inconvenience to the user. Easing the integration effort to achieve interoperability is an important enabling aspect of smart grid deployments, and requires cooperation between the IT and OT organizations.

Corporate network requirements may require different considerations from operational traffic such as performance, data priority, and so forth Also a scheme to separate the corporate data from the operational data must be developed as necessary to ensure the integrity of the critical operational data is not compromised in terms of latency, performance, reliability, and security. Therefore the strategy must lead to a design to address and identify the corporate data and how it will be segmented from the operational data, including access through firewalls and trusted networks. While the consideration of VoIP requires that it be handled as real-time data to ensure voice quality parameters are met, it still must be considered a lower priority than critical operational data. In some cases, non-real-time engineering data retrieved from protective relays or other field operational devices may also ride in the corporate portion of the network.

The metrics for communications system performance include capacity, delay response, and bandwidth demand. Some applications require low delay response but impose low bandwidth demand, while others can tolerate delay but impose a high bandwidth demand.

Business Continuity and Disaster Recovery

The provision of capabilities that allow planning for potential emergency situations and protect the electric power grid against electronic intrusion and other attacks is a common concern among the IT and OT networks. There is an increasing concern about the interconnection of control centers and corporate data networks, the widespread use of dial-up modems, and the use of public telecommunications networks as sources of vulnerabilities for the power networks. In addition, business continuity considerations and considerations for backup control centers typically go hand-in-hand with Corporate IT Governance requirements, which will require some level of compliance.

Options for failover between primary and backup control centers can be facilitated by the communications architecture, depending on the transport options available. If using Internet protocol (IP) or Multi-protocol label switching (MPLS) for the unified communications, automatic reroute to a backup control center can be accomplished in a few seconds if the path is lost to the primary control center; however network design is more critical for Quality-of-Service (QoS) planning to ensure critical operational data is a priority over other *non-operational* traffic in times of limited bandwidth. This is contrasted with a *point-to-point* time division multiplex (TDM) arrangement that is much more robust, but may require dedicated circuits to each location (and possibly requiring dual-ported RTUs), and at much more expense. However point-to-point switchovers can be facilitated through the use of Digital Access Cross Connect (DACS) systems to make the point-to-point architecture more efficient and cost-effective. TDM arrangements and point-to-point communications are architectures not typically found in an IT networking environment. The OT organization may need to be convinced that newer technologies such as MPLS can provide as reliable and secure service as TDM.

A solid supporting cyber security program, guideline and roadmap are critical components to enable an integrated network as well as guard against disruptions, cyber security intrusions and common errors and omissions. With the implementation of new technology, the integration of new and existing supporting IT and OT infrastructures and the decentralization of physical assets identifies new cyber security requirements and solutions that are adaptive and flexible in order to maintain efficiency and ensure ongoing confidentiality, integrity and availability.

Table 5-5
IT and OT Data Network Comparisons

	Differences	Similarities	Synergies
Engineering and Design	• Prioritization of OT mission critical data over network • Network performance requirements • System reliability requirements • OT is NERC/CIP driven	• Disaster recovery requirements • Network management requirements • Cyber security requirements	• Potential for integrated network management • Common transport for economy of scale (that is Smart Grid/DMS/OMS integration)
Development/ Build	• Hardware *hardened* for OT environment • OT preference for private facilities • Segmentation of mission critical OT data • Equipment lifecycles	• Same as above • Technologies • Use of firewalls for controlled access	Same as above
Maintenance and Support	• Remote access procedures • Equipment skill set requirements	• Defined processes and procedures • Service level agreements	• Cross training on common equipment • Potential leverage of existing central support areas (that is utilize groups already on 24 hour call such as distribution operations

Grid Modernization – Change Management

Implementing new technology to the distribution control center (DCC) has its challenges and opportunities with IT and OT. This does not address the amount of change in processes that result from implementing a new DMS or any other advanced applications used by the DCC. Many of these new technologies transition manual paper processes to electronic computer assisted decision-making. A change management plan should be considered when implementing any new technology.

A change management plan includes understanding the change, taking ownership of the change, communicating the change, executing the change, and monitoring the change. Most DMS change management plans are not a one-time process. As the DCC gets more comfortable using the DMS and more advanced applications are implemented, it can be iterative process depending on how well the change is implemented and accepted.

Understand the Change

The first step in a change management plan is to understand the change. Change can be viewed upon as positive or negative depending on whom you are talking to within the organization. Selecting a Project Champion or Executive Sponsor along with change leaders is critical to the success of any DDC initiative. They understand the need for change and can effectively communicate this across the organization.

It is important to identify which business areas across the organization are impacted by the change. Change management activities will focus on working with these business areas to assure that they are well informed along with including them in designing, planning and developing of the DMS implementation. The emphasis and goal is to develop ownership and buy-in with those impacted. For example, when implementing a new DMS, the DDC, IT and OT are not the only areas impacted by this change. Field operations, planners, asset management, and customers can all be impacted by this.

It is important to communicate the project benefits and business process impacts to those business areas affected by the change. Typically, workshops are used to develop the to-be business process maps and identify gaps for the organizations impacted. With DMS and the advanced applications, current as built information is even more critical for the DDC to manage the system. The backlog *gap* is important to address during this step.

DMS changes the DDC’s manual processes to an electronic process. This includes changes from a paper based pin map to an electronic pin map, paper based switching plans to electronic switching plans using planned outage study tools, fault isolation and service restoration analysis when restoring outages. All this information will be used in building effective training and implementation plans.

Taking Ownership of the Change

Now that the business areas impacted by the change have been identified, the next step is to develop a list of Stakeholders from each area. Industry experience has proven that if the major process owners and stakeholders participate in the planning, design and implementation of a new technology, they will be empowered and motivated to make the implementation successful.

A change readiness assessment is essential to assess the key Stakeholders’ needs and identify possible issues and risks to the project. Focus groups are an effective way to bring business areas together to discuss the changes, get two-way feedback, identify potential issues, and ask how they want to be informed on project progress. The results from these meetings are used to prepare the assessment and develop a communications plan. The Stakeholder plan must be continually monitored to gauge key Stakeholders’ level of buy-in. With DMS, many of the processes, which were currently done by other parts of the organization (field operations, planning), will now be centralized and done by the DDC. There must be buy-in and trust in order for the DDC to be successful.

Communicating the Change

With the stakeholders and their expectations identified, a comprehensive communications plan should be developed to support the DMS implementation. The overall goal of the communications efforts is to provide timely information to all targeted audiences while keeping them actively involved. Regular communication updates on the status should be initiated throughout the life of the project. Depending on the audience, communications can be periodic, regular or on an as-needed basis. The communications plan is a living document and should be regularly reviewed, revised and adapted to support a successful DMS implementation. A variety of communication materials can be developed to support the communications plan. For example, monthly status reports and schedule updates are an effective way to provide timely updates to the stakeholders. These may need to be tailored depending on the audience.

Executing the Change

With the communications plan developed, the next step is to execute the change. The to-be process maps and gap assessments can be used to identify how employees are impacted by the changes. A staffing analysis should be completed to determine the tasks, skill sets and competencies required to support the DMS implementation. The results of the analysis will help determine the staffing plan required to support the implementation. It is important to work with the Human Resources and Labor Relations departments to determine the options for executing the staffing plan. After the staffing plan is developed, an employee transition plan should be developed to leverage those impacted employees' experience and knowledge. A transition plan may include the following:

- Transitioning impacted employees to the newly created DDC positions based on their skill level or encouraging them to apply to the new positions
- Offering impacted employees the opportunity to shadow and/or investigate other positions
- Offering cross-training and training opportunities to impacted employees
- Providing impacted employees an opportunity to support the DDC implementation rather than using contractors

The information gathered from the to-be process mapping, gap analysis, and staffing analysis should be used to identify the training required to implement the staffing plan. A comprehensive training plan will facilitate and support a successful DMS implementation. The training plan should focus on developing the skills and knowledge needed to operate and maintain the DMS implementation. For example, this should include how to use the DMS, how to interpret the results, how to communicate and dispatch the results, how to identify issues with the results, and so forth A training needs assessment (TNA) should be completed with each impacted business area. The TNAs will gather the information needed to develop each specific training course.

Monitoring the Change

As part of the change management plan, it is important to track and monitor the performance and success of the Smart Grid implementation. Key Performance Indicators (KPI), identified in the business case, should be monitored regularly to ensure the project is achieving and sustaining the expected Smart Grid benefits. Some examples of KPIs include operational savings, safety measurements, and reliability indices (SAIFI, SAIDI/CAIDI, MAIFI, outage response time).

Recommendation: Developing a change management plan is critical to the success of any DMS implementation and to ensure the project benefits are realized. DMS changes many of the utilities' business processes. An effective change management plan includes understanding the change, taking ownership of the change, communicating the change, executing the change, and monitoring the change. A DMS change management plan is an iterative process to ensure the changes are implemented and accepted across the entire organization and not just DCC, IT and OT.

Common Process Changes and Benefits Enabled by DMS

Table 5-6 summarizes common business process changes that are enabled by grid modernization, specifically the implementation of DMS, functional areas impacted by the changes, and benefits for the utility from making those changes.

Table 5-6
DMS Enabled Business Process Changes and Benefits

DMS and Advanced Applications	Changes	Areas Impacted	Benefits
Pin Map	Move from a paper based process (static model) to manage the distribution network to an electronic pin map (dynamic model).	• DDC • Field Operations • Asset Management (up-to-date models)	• Provide a single, consistent view of the distribution network • Geographic display of assets, crews, and abnormal states • Other parts of the organization are able to view up-to-date distribution network information
Network Analysis	Ability to electronically view the distribution network in near real-time.	• DDC • Asset Management (up-to-date models)	Proactively identify distribution network issues related to power flow, losses.
Switching Operations	Move from paper based switching plans done by other parts of the organization (Field Ops, Planning) to electronic switch plans.	• DDC • Field Operations • Planning	• Used for planned and unplanned switching. • Validate switching plans prior to executing by reviewing load and volt/VAR
Fault Isolation and Service Restoration	Automated tools to optimally restore the system.	• DDC • Field Operations • Customers	Effectively isolate faults and provide optimal service restoration.
Feeder Reconfiguration	Automated tools to optimally restore the system.	• DDC • Field Operations • Customers	Optimally restores the distribution network to normal configuration by eliminating overloads.
Planned Outage Study	Electronically generate switching plans to support planned outages.	• DDC • Field Operations • Planning	Provide a central location to prepare, evaluate and manage scheduled outages.
Load and Volt/VAR Management	Automated tools to optimize the system.	• DDC • Field Operations • Customers	Optimizes and coordinates capacitors and voltage regulators to maintain the system within voltage limits.
Outage Management	Ability to manage outages centrally by using more than just customer calls.	• DDC • Field Operations • AMI • Customers	Provide a central location to manage unscheduled and scheduled outages using data from SCADA, AMI, and customer calls to effectively predicting the probable device to efficiently dispatch field crews.

Summary

The need for real-time analytics – getting the right data to the right people at the right time to make the right decisions – to efficiently operate the increasingly complex power grid requires integrating Information Technology (IT) and Operational Technology (OT). Today's power grid is very dynamic, incorporating more distributed and intermittent renewable generation resources and demand side management programs while operating within slimmer operating margins than ever before. Combining IT with OT leverages the strengths of both, optimizes resources, maximizes performance and benefits by facilitating the data and information flow (business intelligence) among operational systems as well as among a growing pool of internal and external stakeholders and decision makers. As a result, using common IT processes and tools to draw better insights from real-time operational systems has become the growing trend across smart grid initiatives.

The convergence of IT and OT can be a major challenge for utilities, both technically and business-wise. It involves different systems and organizations, including both new and legacy operational structures, business processes and objectives. The challenge also requires utilities to change how the utility business has operated for years. This includes breaking down silos, sharing data and information without compromising safety, security and protection of assets, and operating the power grid more efficiently and reliability in an increasingly dynamic operating environment. It will require IT to think more like OT, and OT to think more like IT.

DMS, as in integral part of distribution grid modernization, enables many business process changes that are very beneficial to the utility's grid operations. However, the changes must be managed to realize and sustain these benefits.

Service Oriented Architecture with an Enterprise Service Bus

SOA/ESB improves information flow, and hence greater benefits, across the utility enterprise by making it easier and quicker to distribute data of an application for further processing, analysis, and presentation by other applications. An application can publish available services (data and embedded processing of the data wrapped into a package for delivery) to the ESB, and authorized applications can subscribe to the services. An authorized application can also request a service from another application through the ESB. SOA/ESB requires upfront investment to implement but once implemented provides many benefits:

Because the ESB manages the publishing and subscription of services, request and delivery of data and services among applications, it is much more effective to add a new system interface compared to the traditional point-to-point interface approach. A benefit of the ESB is that to replace an application module that has

An SOA/ESB can be used to integrate the legacy system, by coding an *adaptor* to publish its data onto the service bus. Once this *adaptor* is developed, it can be *re-used*, *subscribed by* or *called* by many systems to utilize the data without major additional integration efforts. Complex event processing engines on the SOA/ESB can also be used to filter/analyze data streams in real time and, based on a set of pre-determined, condition-based rules, initiate alarms, take actions, and/or make notifications as necessary. This changes the typical *batch mode-processing* paradigm with a real-time *streaming mode* paradigm.

6

DMS PROCUREMENT STRATEGY

Once the functional and technical DMS requirements have been established as described in the previous sections, the process of obtaining the equipment, software, and services needed to implement these requirements can begin. For purposes of this report, it has been assumed that the electric utility will acquire the necessary items from or more parties that are not part of the electric utility. That is, the electric utility does not intend to design, build, test, install and commission the DMS on its own.

This section provides guidelines on procuring the equipment, software, and services that are usually needed for successful DMS implementation. This includes conducting a Request for Information (RFI) process, a Request for Proposal (RFP) process, bid evaluation, vendor selection, and contract negotiation.

Request for Information

Prior to actually procuring hardware, software, and services for a DMS project, many electric utilities elect to do a *Request for Information* (RFI). An advertised solicitation for a DMS consultant or vendor RFI may draw interest from a large number of consultants of all types with different levels of expertise. Evaluating proposals from a large number of consultants could be a very time consuming and expensive task. The RFI process is a very good way to eliminate the less qualified consultants and focus on the most qualified. The short list should be invited to bid on a more detailed consulting RFP that is developed after the RFI has been completed.

There are many potential DMS suppliers and many consultants that can supplement the electric utility staff by providing subject matter expertise. Soliciting and evaluating detailed proposals from dozens of potential vendors and consultants for the required equipment, software, and services would be an enormous task. Instead, many utilities elect to conduct an RFI process to learn more about the qualified vendor or consultant offerings and qualifications of the proponents. The results of this process are then used to narrow the list of prospective bidders to a manageable *short list* of the most qualified proponents who will be invited to submit detailed proposals. Usually three or four of the proponents are selected for the short list via the RFI process.

The RFI may also be used to obtain expert advice about how difficult and unusual DMS tasks or requirements might be handled. For example, if the electric utility is unsure how it can deal with poor quality GIS data (a common problem) or unusual cyber security issues, the RFI provides a convenient mechanism to ask for suggestions from entities that have experience in the areas of concern.

In most cases, the RFI is not used to actually procure the necessary hardware, software and/or services. The procurement is done using a much more detailed document – the Request for Proposal (RFP) – which is described later in this section.

This document discusses considerations for conducting an RFI for DMS vendors and DMS consultants, the objective being to obtain useful information and to develop a qualified short list of proponents.

Objectives for the Consultant RFI

Many electric utilities obtain the services of an expert consultant to help with the DMS planning, procurement, and implementation. Qualified consultants can supply very useful information based on past experience in some or all of the following activities. Note that an electric utility may elect to hire a consultant for one, some, or all of the services listed below.

- Building the business case for DMS
- Identifying functional and technical requirements
- Developing an implementation strategy (roadmap) for DMS
- Preparing an RFP
- Reviewing and evaluating vendor proposals
- Providing assistance during the design, build, and implementation phase of the project

If the electric utility is not experienced in DMS implementation, the consultant can provide expert advice throughout the project. For experienced utilities, the consultant can augment the utility staff and provide information on the latest offerings and success stories.

The following sections contain additional information about the types of information that can be obtained via a Consultant RFI.

Expert Advice

The RFI is a great way to obtain suggestions on how to handle difficult and unique circumstances that your company is facing. The RFI should briefly describe your problem or need and ask how the consultant would go about solving the problem or satisfying the need. For example, if the need is to select a DMS vendor, the RFI should ask the proponents to describe how they would go about doing this. Proponents should provide a list of recommended tasks, descriptions of each task, approximate time lines, and samples of these tasks from recent past projects.

Electric utilities should get advice on how to solve some of the difficult problems (tough spots). It is a good idea to ask how the proponents would address some of your key concerns and constraints and uncertainties. Qualified consultants will provide real insight and innovative suggestions; non-qualified proponents will state the obvious or the impractical.

Assessing the Qualifications and Available Resources

The main purpose for the RFI is usually to develop a *short list* of the most qualified consultants that will be requested to submit a formal proposal to provide the necessary services. The RFI should ask proponents to identify the skillsets needed for such an assignment. Qualified proponents will know that a variety of skillsets are needed for projects of this type, including operation knowledge, power engineering, information technology, communications, and other areas. If they don't mention all of these necessary skills, they probably have a focus that is too narrow to effectively satisfy all of your needs.

The RFI should determine the qualifications and level of experience of the consultant. Good questions to ask include:

What projects of similar scope, magnitude and level of responsibility has the consultant completed in the past 3 - 5 years? For each listed project, the proponent should explain the specific role the proposed personnel played. Just being part of a project is meaningless if someone else did the essential work.

It should be noted that determining the qualifications of any particular company (consultant or DMS vendor) has become increasingly difficult due to the number of acquisitions, mergers, and job changes by key personnel that have taken place in this industry. For example, teammates on a project may have joined different consulting firms, resulting in two firms taking credit for the same project experience. Similar situations can be observed when assessing the qualifications of DMS vendors; numerous key acquisitions have taken place that may confuse the question of *"Who did what?"* The best way to sort out this issue is to look at the specific experience claimed by the proposed personnel, not the proposing companies. If two individuals claim to have done the same work, contact the Project Manager of the project in question to help sort out this issue.

- **Determine the available resources:** The proponents should identify the available manpower resources for each main activity. A *one-man* show is never a good idea. Proponents should describe the specific skillsets that are needed to complete the job and identify the specific personnel that would provide the skill sets. Proponents should also have a primary and at least one backup in each key skill set area. During the RFI process, the electric utility should receive a resume describing the experience (especially the recent experience) of each individual. In addition, the utility company should obtain information on current workload of each proposed individual and availability of the individual to work on your project.
- **Independence of the Consultant:** The consultant should provide unbiased advice that is solely in the interest of the utility. Therefore, the consultant must not have any vested financial interest in any vendor or solution approach. In other words, the consultant should not derive any incremental benefit (financial or otherwise) if a particular vendor is ultimately selected or a particular solution approach is used. Note that having worked closely with a vendor on one or more projects or having selected a particular vendor on a recent project should not disqualify a consultant on the basis of being biased. In fact, familiarity with a vendor's products is often a significant advantage during system design and integration.
- **Budgetary Pricing:** Cost estimates provided during the RFI stage are usually non-binding, so it is risky to base consultant or vendor *shortlisting* on pricing information received at this stage. The numbers are useful for gauging whether the budget is sufficient. But it is risky to use RFI cost estimates to short list a consultant or vendor. Consultants or vendor may suggest an artificially low price that is meaningless unless contractual obligations are involved.

Contents of the RFI

This section identifies the recommended content of the RFI. Note that the RFI contents are approximately the same for a Consultant RFI and a Vendor RFI.

- **Project Overview:** This section of the RFI should summarize the overall objectives for project. A rough timeline for accomplishing the work (including key milestones) should be provided, and any major constraints should be identified. If your company has developed a business case for the proposed project (generally a good idea), it should be fairly easy to identify and describe the objectives. This should not be a very detailed description - just enough to avoid confusion about what is needed.
- **Preliminary Statement of the Scope of Work:** The RFI should describe the intended scope of the proposed consulting assignment or DMS objectives. This should be a list of the anticipated tasks for the consultant. Keep in mind that the list of consulting activities may change based on the results of the RFI (the proponent consults may suggest a task or two you didn't think of). Consulting Tasks may include (but are not limited to):
- Developing or reviewing the business case;
- Developing a DMS implementation plan (identify functions, conceptual architecture, implementation strategy);
- Conducting a DMS vendor RFI;
- Developing detailed DMS specifications and procurement documents;
- Developing a bid evaluation strategy;
- Providing assistance during system design, build, test, install, and commissioning activities.
- **RFI Questions:** The RFI should include a list of specific questions that are needed to determine the proponent qualifications, subject matter expertise, proposed work plan, and available resources. Questions should be phrased to avoid simple *Yes/No* answers. Questions that stare with the words *"Tell me how…"* often work best. Topics to ask questions about should include:
- Available resources and proposed personnel, including:
- Who will do the work?
- What percentage of time will each person be dedicated to your project (full time, half time, cameo appearance, and so forth)?
- How much time will be spent on site in your offices?
- Should ask the proponents to explain what the specific subject matter expertise of each person is. Depending on project scope, consulting team should include engineering-operations person, and integration and communication (ITC) expert, at a minimum.
- Recent past experience (last 3 to 5 years) on similar consulting assignments:
- What was the objective and scope of each project?
- What specific tasks were done by the proposed personnel?
- What specific activities are proposed to meet your objectives? What is the schedule for completing these activities?

- What software tools and formal methodologies are available to assist in completing the proposed tasks? Typical tools might include standard DMS specifications, DMS benefit cost analysis tools, bid evaluation framework and spreadsheet, and risk assessment spreadsheet.
- Should ask specific questions about recommended functional and technical requirements for the major applications of interest (for example, VVO, FLISR, OMS). Consultants should have a thorough understanding of the requirements along with a solid understanding about what's practical and what is not practical. The consultant should alert you to the potential technology limitations and pitfalls so that you do not make the same mistakes others have made in the past.
- Should ask questions to get suggestions about how to handle anticipated *tough spots*, like cyber security issues and GIS data modeling errors

The bottom line is to ask lots of questions that will help you pick the right consultant. This information is free of charge and commitment – you should take advantage of it!

RFI Formatting Requirements

The RFI instructions should require that the RFI responses have a specified organization and content. If all proponents use the same organization and provide the same type of content, reviewing the RFI responses will be much simpler. Any proposal that doesn't follow the format should be rejected.

At a minimum, the RFI response should include the items listed below:

- Executive summary that explains the proposed approach, identifies RFI highlights, unique qualifications, and key project experiences, and explains any teaming arrangement that is being proposed
- Concise answers to all questions
- Organization chart for the proposed project team
- Resumes for all proposed team members. Resumes should be focused on relevant experience during recent years

RFI Presentation

It is always a good idea to invite at least some of the proponent consultants in for a formal presentation of the qualifications and face-to-face Question/Answer session. Each session should last from ½ day (preferred) to a full day. Personnel who will do the work (especially the proposed consulting project manager) should attend and do the majority of the presenting. Talking only with marketing/sales specialists is most likely a waste of time.

Evaluating RFI Responses

RFI responses should be evaluated by all of the major stakeholders for the project. For a DMS project, the evaluation team should include representatives of the distribution system operators, IT specialists, engineers, project management, SCADA and telecommunications groups, and others that will be impacted by the DMS implementation.

It is strongly recommended that the electric utility develop a bid evaluation methodology prior to receiving proposals from the proponents. This will avoid potential bias that may occur upon reading the RFI responses and meeting the proposed individuals from each proponent. The RFI response evaluation methodology should include numeric scoring of key pre-established criteria that are weighted in accordance with perceived pre-established priorities. Scoring criteria should include (but not be limited to) the items listed below:

- Recent experience on relevant, similar projects
- Available resources
- Answers to questions (technical and commercial)
- Insightful answers to questions about *tough* spots
- Useful and innovative information that was not specifically requested
- Quality of RFI response presentation
- Risk factors

RFI for DMS Vendor Proponents

The RFI for DMS vendors should be similar to the RFI for consultants. Emphasis should be placed on relevant recent experience on similar projects, available resources, initial assessment of standard offerings, ability to meet overall requirements with standard offerings, (minimize level of development), quality of RFI presentation, and other such factors.

Request for Proposal

The *Request for Proposal* (RFP) includes all of the information needed to solicit firm fixed price proposals for the required DMS equipment, software, and services. After the functional and physical needs have been established, an RFP document should be prepared that will be used to solicit actual vendor bids to supply the system. The RFP document includes the technical and commercial requirements for the equipment, software and services (including integration services) to be furnished by the DMS supplier.

The RFP should consist of a single specification that will cover all project deliverables, placing the primary responsibility for the delivery of all hardware, software, and required vendor services on a single vendor who will have ultimate responsibility for system delivery. Technical requirements should be described **functionally** with sufficient detail to avoid confusion, while providing maximum flexibility for bidders to propose their standard design. This will minimize project cost and risk.

The RFP should include the following sections:

Instructions to bidders: The *instructions to bidders* portion of the RFP document should provide basic information about the procurement and should describe the expectations for the proposals submitted by the bidders. At a minimum, this section of the RFP document should include:

- *Project overview:* a brief description of the project objectives and required deliverables, along with the proposal due date and delivery instructions.
- *Key project dates:* a list of key calendar dates that will constrain the project schedule, such as the required project completion date. This section of the RFP should also if the DMS is required to align with other major projects planned by the electric utility. For example, the DMS implementation schedule may need to be coordinated with the deployment of an AMI

project or other major operational support project. In addition, the key dates section should identify ranges of dates (for example, special events) when on site implementation activities must be paused.

- *Summary of expected vendor and electric utility responsibilities during the project*: Few in any electric utilities will require a completely *turn key* project in which the vendor has the sole responsibility for completing all project activities. Rather, the project activities are divided between the vendor, the utility company, and in most cases, one or more third parties (consultant, system integrator, installer, and so forth). This section of the RFP should explain the anticipated responsibilities of all parties involved in the project.
- *Required proposal content*: This section should identify the specific format that is required for the proposal, including specific forms that must be completed by the bidders. Bid review and evaluation is an enormous undertaking, but the process can be streamlined if all bidders follow the same basic proposal format, and also provide specified information to enable the utility to perform the evaluation. Proposal format should be treated very seriously - proposals that do not follow the specified formatting instructions should be rejected. Following is the recommended proposal content:
- Bid Acceptance Form: This section shall include a fully completed and signed Bid Acceptance Form. Pricing fields shall be filled in only on the priced copies of the Bidder's proposal. These fields shall be left blank on the unpriced copies.
- Executive Summary: The proposal shall include an Executive Summary that summarizes the proposed hardware, software, and services and provides a brief description of the major RDA system components and technical features. The Executive Summary shall identify the Bidder's qualifications for this project, and shall explain the Bidder's experience in supplying systems of the type described in this RFP.
- Quality Assurance Program Certification: This section of the proposal shall include certification of the Bidder's Quality Assurance program from an independent organization that is qualified and accredited to perform such certification.
- Minimum *MUST* Requirements Table: All RFP responses shall satisfy certain minimum (*MUST*) requirements that the utility company considers especially critical. The electric utility may reject any proposal that fails to satisfy all of these minimum *MUST* requirements. If the requirement is completely satisfied for the DMS, or *No* if the requirement is not completely satisfied. The Bidder may insert comments if necessary to clarify its *Yes* or *No* response.
- Technical Response: This section of the response shall specifically address the requirements described in the technical specification section of the RFP.
- Configuration Block Diagram: The Proposal should include a configuration block diagram showing the major components of the proposed DMS, interconnections between components, communication facilities, and interfaces to external systems. The configuration block diagram shall clearly identify all devices that are optional and all items that are vendor supplied and electric utility-supplied.

- Project Plan and Schedule: Bidders should provide a detailed project plan and preliminary schedule for the design, development, integration, configuration, commissioning and testing of the systems required for the DMS. The Project Schedule shall show major Vendor and electric utility activities starting with the Award of Contract and ending with the complete DMS in service. The Preliminary Project Schedule shall identify major events, payment milestones, and interdependencies between events. Bidders shall clearly identify on the schedule significant activities by electric utility personnel that must be completed on time to avoid significant delays. Bidders must provide an estimate of the resources required from both the Vendor and the electric utility for completion of the project.
- Project Organization and Key Project Personnel: This section of the proposal shall include a diagram showing the proposed project organization. This diagram shall identify all key positions on the proposed project team, including all Bidder and Subcontractor (if any) positions, and the reporting structure within the proposed project team. The diagram shall also show the interface or primary point of contact with the electric utility's project manager.
- Key project personnel proposed for the project shall also be identified in this section of the proposal. At a minimum, the proposal shall identify the specific persons proposed as Project Manager, Lead Hardware Engineer, Communication Specialist (if different from the Lead Hardware Engineer), and Lead Software Engineer. The proposal shall describe the responsibilities of each individual for this project and the approximate amount of time each person will devote to this project. Detailed resumes identifying the relevant project experience of each individual shall also be included in this section of the proposal.
- List of Deliverables: A complete, detailed List of Deliverables shall be provided that lists the type and quantity of all hardware, software, and documentation items included in the base proposal and each optional item. Each line item shall indicate manufacturer, model number, quantity, and options selected. Vendor-supplied services shall also be identified in the list of deliverables.
- Background Response Form: Bidders must provide information on the Bidder's company, including details of Bidder experience and utility contacts for similar electric utility DMS projects, especially DMS projects that have included the advanced functionality required by the electric utility. In addition, Bidders must provide a copy of the company's most recent financial information.
- Answers to Questions: Bidders must provide detailed and comprehensive responses to the questionnaire included in the RFP. This section should repeat the question followed by the Bidder's response. Answers to the questions shall be in the order of the corresponding questions, and shall be clearly numbered.
- Table of Compliance (TOC): Bidders must provide a Table of Compliance (TOC) indicating the Bidder's compliance for the Commercial and Technical requirements. The Bidder shall record compliance and deviations in a suitable table generated by the Bidder corresponding to each numbered section of the RFP. The TOC shall contain the following fields (columns):
- Section Number: The section number corresponding to Duke's RFP document.
- Section Title: The section and subsection name corresponding to the Duke RFP document.
- Compliance Status: Bidder's compliance according to one of the following codes. Only one symbol shall be assigned.

- C – Compliant: The Bidder understands and complies with all requirements in the corresponding reference. There shall be no explanations, interpretations, or comments added to the TOC for a section, subsection, or paragraph marked as ‘C’.
- A – Alternate: The Bidder proposes an alternate method that may not completely comply with the RFP.
- X – Exception: The Bidder takes exception to the requirements and alternate solution is proposed.
- Explanation: The explanation field shall be blank for requirements with a ‘C’ in the Compliance status field. If an ‘A’ was entered in the Compliance status field, the Bidder shall explain how the proposed offering differs from the specified requirement. The Bidder shall identify all differences between the proposed Alternative solution and the specified requirements.
- Price Worksheets: Bidders must provide price information using the Price Worksheets contained in the RFP. The completed Price Worksheets shall be included only in the priced copies of the proposal.

Technical Requirements: This portion of the RFP document should include the technical requirements for the equipment, software and services (including integration services) to be furnished by the DMS supplier. The RFP should consist of a single specification that will cover all project deliverables, placing the primary responsibility for the delivery of all hardware, software, and required vendor services on a single vendor who will have ultimate responsibility for system delivery. Technical requirements should be described functionally with sufficient detail to avoid confusion, while providing maximum flexibility for bidders to propose their standard design. This will minimize project cost and risk.

The RFP should include the following sections (typical content is identified in parentheses):

- Functional requirements (data acquisition and control functions, alarm processing, DMS advanced applications, reports and displays, historical data storage and retrieval, special application functions, external interfaces).
- General requirements (equipment service conditions, applicable standards, spare capacity and expansion capability, system performance and response time, maximum equipment utilization, system availability definition and requirements, and so forth).
- Hardware characteristics (Requirements for processors, servers, printers, local area networks, communication processors, time reference units, enclosures, uninterruptible power supplies, interconnecting cables, special tools, spare parts, and so forth).
- Software and firmware characteristics (Operating systems, relational database system, database and display maintenance software, on line and off line diagnostic software, vendor remote dial-in/VPN interface for future support, network management software, and so forth).
- Communication interfaces.
- Documentation and training (Documentation: user, maintenance, system administrator manuals; installation and startup documentation; as built drawings, and so forth). (Training: user training, hardware and software maintenance, system administration; training location and cycles.)

- Inspection and Testing (factory tests, site tests, availability tests).
- Other vendor supplied services (system integration services, maintenance support through warranty, project management, installation supervision, and so forth).
- Appendices (input and output point counts, sample displays, and so forth).

Proposal Evaluation

This section summarizes the recommended procedure for evaluating RFP responses from the DMS proponents. Each RFP response should be evaluated in following major evaluation categories:

- Terms of Reference (Functions, Technology, Services)
- Total Cost of Ownership
- Risk Assessment and Bid Demonstration
- Weighting factors should be assigned to each of the major evaluation categories list above to indicate the relative priority of each category. The bid evaluation team should determine a score for each proposal in each of these three categories. These category scores will then be multiplied by category weighting factors to determine a total score for each proposal. This total score will be used to commence contract negotiations with the selected vendor.
- Financial and commercial capabilities of each vendor may also be included in the list of major evaluated categories. However, these categories are often evaluated on a pass-fail basis by the electric utility's legal and financial groups.

Minimum (MUST) Requirements

The first step in the evaluation process is to ensure that each proposal satisfies the minimum (*MUST*) requirements that have been established for the project. *MUST* requirements are usually related to essential project requirements that need to be accomplished to ensure project success.

MUST requirements are expressed if such a way that they are either satisfied or not satisfied (that is, there is no way to partially complete the requirement and still be successful). The list of MUST requirements are always project specific. However, the examples listed below illustrate the type of requirements that have been classified as *MUSTs*:

- The Proposal MUST include all of the Key DMS Requirements listed in the Terms of Reference: Any proposal that takes complete exception (compliance code "X") to any of the key DMS requirements does not satisfy this MUST requirement.
- The Proposal MUST include services to implement the required interfaces between DMS and the existing GIS: These services may be performed by the Proponent or by the Proponent's Subcontractor.
- The proposed DMS architecture MUST be fully compliant with the electric utility's IT standards
- Final acceptance in the proposed DMS implementation schedule MUST occur on or before the contract end date specified in the bidding instructions

If the evaluation team determines that one or more of the *MUST* criteria listed above is not satisfied, the evaluation of the proposal in question should be paused until further clarification of the issue is received from the proponent in question and a course of action as agreed to with the DMS Steering Committee. Alternately, the proposal in question may be rejected outright.

Category Scoring

Category scoring is described in the following sections.

Category Weighting Factors

Weighting factors should be assigned to each major category. To prevent scoring bias, weighting factors must be assigned before the bid review and evaluation begins. Typically, weighting factors are assigned by and known only to the DMS management steering committee. The total of these category-weighting factors must be 100%. As an example, the weighting factors shown in Figure 6-1 below are assigned to each of the categories. As shown in the table, fifty percent (50%) of the total proposal score is associated with the terms of reference response (functions, technology, and services), fifteen percent (15%) is associated with the bid demonstration and risk factors, and 35% is associated with the Total Cost of Ownership (TCO). Note that these percentages are given as a representative example and should not be considered recommended factors for every project. The electric utility should determine appropriate weighting factors that are appropriate for its own unique situation.

Category Weighting Factors

Item	Overall Weight (%)
Terms of Reference	50
Total Cost of Ownership	35
Demonstration & Risk Assessment	15
Total	**100**

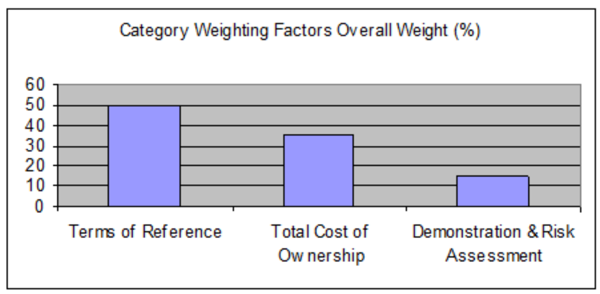


Figure 6-1
Category Weighting Factors

The scoring of each category is detailed in the following sections.

Terms of Reference

The Terms of Reference category includes Proponent responses to the technical requirements section of the RFP Terms of Reference (TOR). These sections cover all DMS hardware, software, and services that will be furnished as part of the DMS procurement. As indicated in the previous section, 50% of the total proponent score is associated with the Terms of Reference category in the sample bid evaluation described in this section.

For bid evaluation purposes, the TOR category can be subdivided into the following three main areas:

- **Functional:** this area includes the DMS functional requirements: VVO, FLISR, Data Acquisition and Control, User Interface, and other DMS applications. This area includes all of the functions identified in the Functional Requirements section of the Technical Specification.
- **Technical:** this area includes the overall system architecture, hardware and software, and interfaces to external systems. The requirements in this area are detailed in the Technical specification sections that cover System Architecture and Interfaces, System Sizing, Performance, and Availability, Hardware Characteristics, and Software Characteristics.
- **Delivered Services:** this area includes testing, documentation, training, installation assistance, sustainment activities, and other services provided by the proponent. Requirements for delivered services are detailed in TOR sections covering overview of requirements, QA and Testing, Documentation and Training, and Sustainment and Implementation Services.

The bid evaluation team members should assign individual scores between 0 and 5 (or 0 to 10) to every numbered requirement identified in the terms of reference. It is important to establish clear definitions about what each score means so that every member of the evaluation team scores each proposal in a consistent manner. Following is one way to assign meaning to each score:

Score	Meaning	Interpretation
5	GOOD	Proponent satisfies or exceeds all elements of the requirement; the proposal exceeds requirements for more than half of the elements
4	Better than AVERAGE but worse than GOOD	Proponent satisfies all elements of the requirement; and the proposal exceeds the requirements for a small number (one or two) of the elements
3	AVERAGE	Proposal satisfies all the elements of the requirement without any major shortcomings or enhancements .
2	Better than POOR but worse than AVERAGE	Proposal satisfies most (more than half) of the requirements.But, there are one or two aspects to the proposal that are not accceptable
1	POOR	Proposal does not satisfy most (more than half) of minimum requirements. Proponent takes exception (no proposal) for some (not all) elements.
0	No response	Proponent takes complete exception to the requirement or did not repond at all to the requirement

Figure 6-2
Assigning Meanings to Individual Requirement Scoring

There is often a tendency in scoring to rate all proponents in the middle (score between 2 and 4) on all items. This results in total weighted scores that are very close together, even if there are clear differences between proponents. One solution to this problem is to use a *forced* scoring method: assign 5 to the best proposal, 1 to the worst proposal, and 3 to the proposal that is in between. This forces the evaluation team members to assign scores that are significantly different even if one proposal is only slightly better than the others.

The individual requirements will be grouped and weighted by section and subsection of the Terms of Reference. Sample section weighting factors are listed in Figure 6-3 below.

Section #	Section Title	Section Weighting Factors (%)
Section 2	Overview of Requirements	4
Section 3	Functional Requirements	46
Section 4	System Architecture and Interfaces	15
Section 5	DMS Sizing, Performance, and Availability	3
Section 6	Master Station Hardware Requirements	3
Section 7	Software Requirements	3
Section 8	Quality Assurance and Testing	8
Section 9	Documentation and Training	8
Section 10	System Implementation and Sustainment	10
	Total	**100**

Figure 6-3
Sample TOR Section Weighting Factors

As seen in Figure 6-3, 46% of the Terms of Reference category scoring is associated with the Functional Requirements Section of the Terms of Reference. This high percentage reflects the relative importance of the functional requirements as well as the sheer number of requirements contained in this section of the TOR. Similarly, 15% of the TOR scoring is associated with System Architecture and Interfaces.

Additional weighting factors should be assigned to TOR subsections and individual requirements contained in the subsections. Critical functions that have a specific impact on the DMS business case (VVO, FLISR, OLPF, data models, user interface, intelligent alarming, and so forth) have been assigned higher weighting factors than non-critical functions (report writing, and so forth). This ensures that a proponent's offerings for critical functions have a greater impact on vendor selection.

The Section, Subsection and Individual Requirement weighting factors have been combined to determine the relative weight of the individual numbered requirements in the TOR. Figure 6-3 shows the sample subsection weighting factors for the Functional Requirements section. Only the subsections that have subsection weight greater that 2% are shown in this table. There are numerous other subsections that have less than 2% weight and are not shown in this table. Figure 6-4 shows the Subsection weighting factors for the System Architecture and Interfaces section.

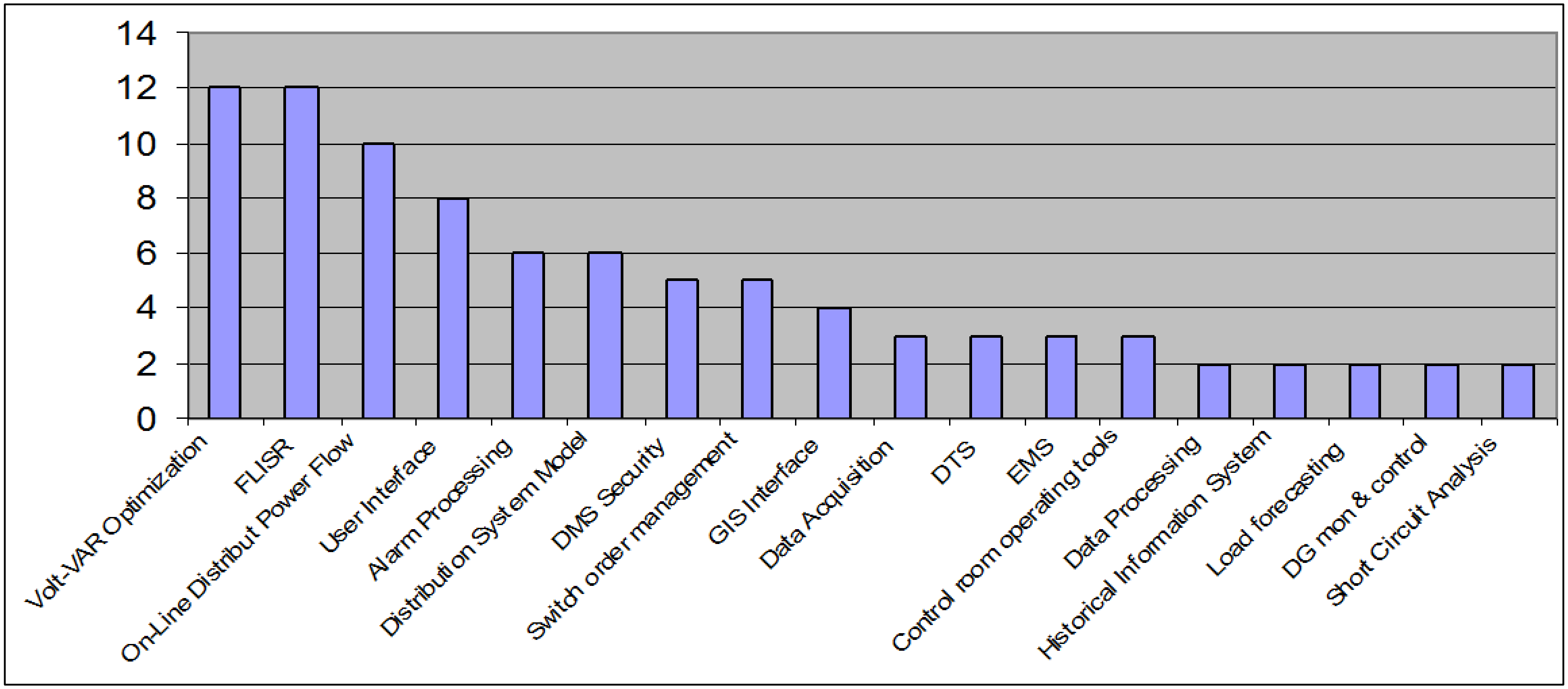


Figure 6-4
Sample Subsection Weighting Factors for the Functional Requirements Section

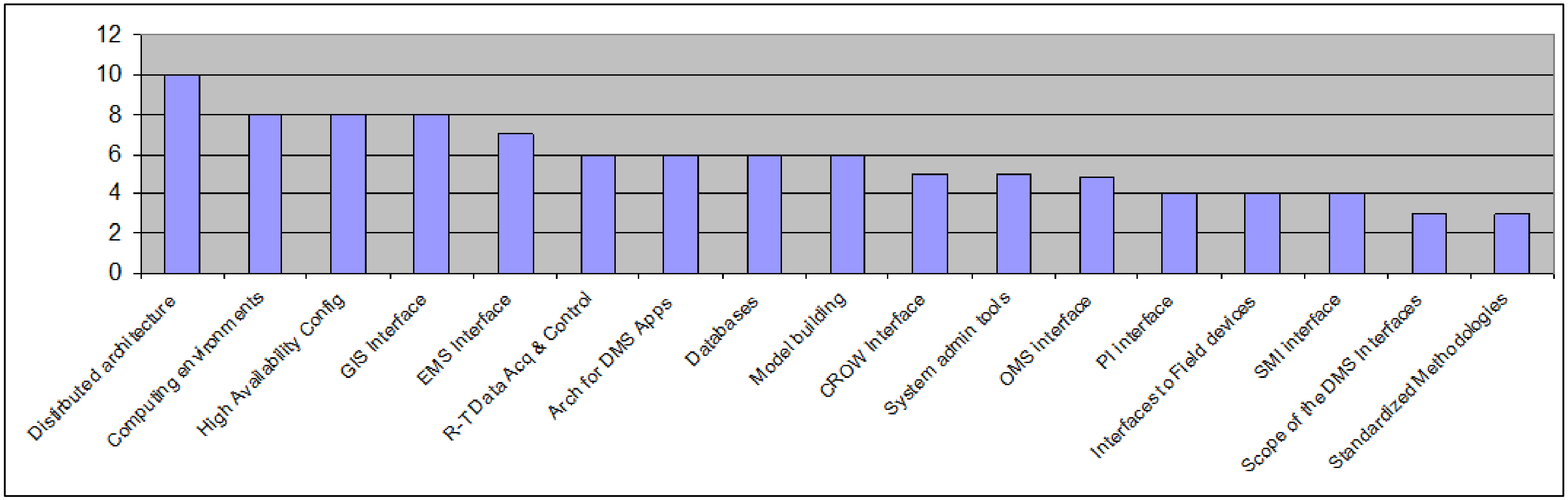


Figure 6-5
Sample Subsection Weighting Factors for the Technical Requirements Section

Bid Demonstration and Risk Assessment

For this sample case, a total of fifteen percent (15%) of the bid evaluation weighing is assigned to the Bid Demonstration and Risk Assessment portions of the evaluation. One-third of the total for this category (five percent of the overall weighting) is assigned to the Bid Demonstration and two-thirds of the total for this category (ten percent of the overall weighting) is assigned to the Risk Assessment.

The following sections contain details about the scoring of these two items.

Bid Demonstration: This portion of the bid evaluation methodology is associated with Proponent performance during the bid demonstration. Five percent of the overall weighting is assigned to this item. The Bid Demonstration individual requirements are further broken down as shown in Figure 6-6.

Item #	Category	Requirement	Weight
1	Demonstration	Conversion of the "raw" data files supplied	5
2	Demonstration	Additional data needed to create model and display	10
3	Demonstration	Full graphic display capabilities and navigation between displays	5
4	Demonstration	Automatic generation of schematic displays	10
5	Demonstration	Alarm processing and displays	5
6	Demonstration	Trend displays	2
7	Demonstration	Data storage and retrieval capabilities	3
8	Demonstration	Demonstrated features of the On-Line Power flow (OLPF) program, includng HMI, ease of use, and OLPF accuracy compared to the expected results	10
9	Demonstration	Demonstrated features of the Volt VAR optimization (VVO) program, includng HMI, ease of use, and VVO accuracy compared to the expected results	15
10	Demonstration	Demonstrated features of the FLISR program, includng HMI, ease of use, and FLISR accuracy compared to the expected results	15
11	Demonstration	Demonstrated features of the switch order management (SOM) program, including HMI, ease of use, and simulated (study mode) operation	10
12	Demonstration	Accuracy of Demand Allocation and Demand Estimation functions compared to expected results	5
13	Demonstration	Demonstration of additional DMS functions beyond the minimum requirements for demonstration	5
		Total	**100**

Figure 6-6
Sample Bid Demonstration Evaluation Factors

Each item in the bid demonstration list shall be scored from 0 to 5 according to the following guidelines:

Table 6-1
Bid Demonstration List

Score	Meaning	Interpretation
5	GOOD	Demonstration exceeds the requirements in most elements of the requirement, there are no signficant shortcomings;
4	Better than AVERAGE but worse than GOOD	Demonstration exceeds the requirements in one or two elements of the requirement, there are no signficant shortcomings;
3	AVERAGE	Demonstration satisfies all the elements of the requirement without any major shortcomings or enhancements .
2	Better than POOR but worse than AVERAGE	Demonstration satisfies most (more than half) of the requirements.But, there are one or two aspects to the demonstration that are not accceptable
1	POOR	Demonstration does not satisfy most (more than half) of minimum requirements. Some (not all) elements are not successfully demonstrated.
0	No response	Item not demonstrated

Risk Assessment: This portion of the bid evaluation methodology is associated with perceived risks associated with each Proponent. For this sample case, ten percent (10%) of the overall weighting is assigned to this item. Each risk item identified during the workshop was assigned scores that indicate the impact (consequences) to the electric utility if the risk item should occur. During the bid evaluation process, a probability of occurrence should be assigned to each proponent-specific risk item for each proponent. The proponent-specific probability should be used along with the impacts assigned during the workshop to computer a score for each risk item.

Guidelines for assigning risk probability scores are listed in the table below:

Table 6-2
Guidelines for Assigning Risk Probability Scores

Risk Probability Score	Interpretation of Each Score
5	Very likely (>75%) that impact will occur
4	Strong probability (50 - 75%) that impact will occur
3	Possible (25 - 50%) that impact will occur
2	Low probability (5 - 25%) that impact will occur
1	Unlikely (<5%) that impact will occur

Total Cost of Ownership

The Total Cost of Ownership (TCO) score should be based on the total life cycle costs of the DMS for each proponent, including the implementation costs (initial procurement cost, installation, and commissioning cost) and sustainment costs for the initial five years of system life. The initial procurement cost should include the proposed costs from each proponent for required hardware, software, and services, and the costs of all options selected by the utility. The initial procurement costs will also include price adjustments assigned by the bid evaluation team to account for proposed items that do not completely satisfy the utility's requirements. For example, if the automatic schematic generator software is not acceptable, the adjustment may be the cost to manually pre-build a set of schematic displays. The sustainment costs for the initial five years of system life should be converted to present value using an appropriate discount rate.

Contract Negotiation

The final step in the procurement process is contract negotiation with the DMS vendor that was selected during the proposal evaluation process. The DMS contract includes three major parts that are discussed in this section:

- Commercial terms
- Pricing
- Technical statement of work

Commercial Terms

The commercial terms that are included in the DMS contract are usually based on the electric utility company's general terms and conditions that are used for most major procurements. In most cases, the utility's standard terms and conditions must be expanded to include several new requirements that are associated with computer based monitoring and control systems. Common additions to the standard terms and conditions are listed below.

Right to use system and make changes without voiding warranty: Electric utilities often need to make changes to the delivered software, such as adding new software applications and building database and displays. The commercial terms and conditions must allow the utility to make such changes without voiding the DMS system warranty. Most database and display changes that are accomplished using the DMS vendor supplied maintenance software are allowed. However, application software developed by the electric utility usually must be reviewed and approved by the DMS vendor to ensure that the new software will not adversely impact the operation, availability, and performance of the vendor supplied software.

Disclosure of interfaces: In most cases, the DMS vendor will not share internal design details about the system software. This is done to protect the confidential details of their proprietary application software. However, very specific details about software design are needed by the electric utilities and their system integrators to enable the design of interfaces between the DMS and external systems to which the DMS must interface (GIS, OMS, and so forth). The DMS contract must provide the electric utility and its system integrator subcontractors with full disclosure of all DMS interfaces to enable the utility to design, build, and implement these interfaces.

Availability of source code: Most vendors will not supply any of the source code for the DMS application software that is delivered to the electric utility. This is deemed necessary to protect their valued intellectual property and trade secrets for analytical software. DMS vendors will in most cases not negotiate on a requirement to supply the customer with the source code. However, the utility must protect its rights to maintain the software in the event that the supplier goes out of business or discontinues support of the version of software that was supplied with the system. The DMS commercial terms and conditions should include a clause that provides access to the source code for system maintenance purpose should either of these events occur. In most cases, the source code will be stored in an escrow facility and will be released to the customer only under specified circumstances such as those listed above.

Right to move software to replacement hardware: The DMS is expected to last between 10 to 15 years without having to perform significant modifications to the application software. However, the system hardware has a much more limited lifetime and will most likely need replacement at least once during this period. The contract terms should guarantee the rights to transfer the original DMS software to the replacement hardware without having to pay additional software license fees.

Complicated definition of *Acceptance*: When the electric distribution utility *accepts* the DMS, this is a very significant event that often triggers the start of the warranty period and the end of vendor maintenance responsibilities, and also typically involves a significant milestone payment that removes most of the utility company's remaining financial leverage. Acceptance for warranty purposes should be defined to mean satisfactory completion of all factory and field acceptance tests, correction of all known variances, and delivery of all contracted equipment, software, and services.

Pricing

One of the most essential parts of the contract is the agreed to pricing. The pricing portion shall clearly state the agreed firm fixed pricing for an agreed statement of work. It is essential that the contracted price be based on pricing information supplied during the competitive bid process. Once a notice of *intent to negotiate* is provided to a vendor, much of the electric utility's leverage gained from the competitive bid process is lost. Pricing information supplied during competitive bidding should include a detailed breakdown of all costs with unit pricing included. This will enable the utility to confirm that pricing has not changed following the *notice to negotiate*.

Many DMS projects will include options for features that may be selected (or declined) on or before a specified date or before a specified project event (for example, start of factory acceptance testing). The contract shall clearly specify the terms and conditions of every option, including pricing, hardware, software, and services to be provided, and decision date or event for selecting or declining the option.

Some unanticipated changes will always be needed following the award of contract. The pricing portion of the contract should clearly identify how such change orders will be handled.

Another significant issue is the milestone payment schedule. Electric utility payments should be based on the successful completion of key project events, such as the contract signing, staging of hardware at the vendors factory, approval of system design, successful completion of factory testing, and successful completion of field testing. Ideally, the milestone payment schedule retains a significant portion of the payment until final acceptance occurs. As a general rule, total cumulative milestone payments at the completion of factory testing should not exceed 60% of the total price.

Statement of Work

The DMS contract must include a detailed statement of work that describes the contracted hardware, software, and services to be supplied by the vendor. The recommended strategy for generating a statement of work is to develop a *conformed specification*. The conformed specification consists of the original terms of reference that has been marked up only as needed to address alternatives and exceptions proposed by the vendor during the competitive bid process.

The advantage of this approach is that the utility has a thorough understanding of its specifications, making this an excellent basis for the contract document. When the conformed specification approach is used, it is important that the contract includes an *order of precedence* that defines the order in which the contract documents will be used to resolve contract disputes. Highest precedence always goes to the commercial terms and conditions. The next document in line should be the conformed specification, followed by Vendor proposal and proposal clarifications.

7 SUMMARY

No portion of the electric power grid has been impacted more significantly by the Smart Grid concept than the electric distribution system. In the past, the distribution portion of the system received little attention compared to transmission and generation systems unless the lights went out. Since the dawn of the smart grid era, many electric distribution utilities have transitioned from (or are in the process of transitioning from) mostly manual, paper-driven business process to electronic computer and communication based decision support and control systems. At the center of attention is the DMS, which will almost certainly play a major role in the future, as smart grid roadmaps become reality.

This report explains how electric utilities can successfully plan, implement and use DMS effectively to accomplish the desired objectives. The report provides a roadmap that electric distribution utilities can use as a guide in performing key DMS implementation activities starting with project inception to DMS contract award. Detailed information is provided on selecting DMS functions to match important business drivers, defining these functions in sufficient detail to support DMS procurement, selecting a vendor and supporting service providers, evaluating vendor proposals, and negotiating a contract with the selected vendor. The report also covers the very important issues regarding the convergence of IT and OT.

This Project Set develops and evaluates advanced distribution system applications for reliability improvement, system optimization, asset management, and distributed resource integration. These applications involve implementation of monitoring equipment (sensors), communications infrastructure, and advanced protection and control functions. The program will support utilities in the migration to distribution management systems with model-based management of the system. The DMS of the future will need to integrate many functions to optimize system performance, reduce losses, optimize voltage and VAR control, improve reliability through system reconfiguration and fast restoration, and integrate distributed resources.

Results and Findings

Electric distribution utilities are just beginning to realize the potential benefits of the DMS concept. Many utilities have conducted limited scale demonstrations of selected advanced grid modernization functions, such as Volt VAR Control and Optimization (VVO) and Fault Location Isolation and Service Restoration (FLISR). While these demonstrations of individual grid modernization applications have generally proved successful, it is clear that widespread deployment of multiple grid modernization applications will require a well-coordinated approach to maximize the benefits of these systems. In addition, future deployments of Distributed Energy Resources (DERs), such as energy storage and distributed generators, will greatly increase the complexity of these individual systems and impose additional burden on system operators who are tasked with overall management of the distribution system. The DMS appears to provide an effective solution to the problem of increasing complexity using a single *as operated* distribution system model.

While the DMS industry is still at a level of infancy, the industry is gaining experience with the new technologies. Numerous utilities have recently *gone live* with a new DMS and have reported that expected significant benefits are being achieved. The model driven DMS solution is providing benefits that go well beyond the simpler rule driven systems of recent years. For example, the DMS solution has proven to be a better approach for managing the complex situations facing distribution system operators. Manual paper driven processes, such as records management and creation of switching orders, are being replaced by electronic, computer assisted processes, thus creating a considerable productivity increase for distribution operations personnel, engineers and other stakeholders.

In light of recent major storm-related outages, electric utilities are seeking ways to manage such events more effectively using technology. Recent DMS projects include outage management functions and well as damage assessment capabilities to more effectively deal with such major events. As a result, there is growing interest with the industry for combined DMS/OMS systems. Vendors that previously focused on DMS/SCADA systems are now adding OMS capabilities to their application suite. Similarly, OMS vendors are adding DMS/SCADA functionality.

Many additional DMS projects are currently underway at this time, with valuable lessons learned being gathered by utilities and vendors alike. EPRI expects to play a major role in tracking and disseminating information about these valuable industry experiences.

Challenges and Objectives

One of the most significant challenges associated with DMS implementation is the lack of a solid business case for making the significant investment associated with this system. To achieve a successful implementation, the DMS must address important business needs related to distribution system operation and performance. The DMS should support current business drivers as well as the electric distribution utility’s long-range vision for distribution system operation and performance. This report includes guidelines for identifying the key short term and long-term issues facing today’s electric distribution utilities. The report also includes guidelines on identifying DMS functions and technologies that can help satisfy these business needs.

One of the most significant challenges facing electric utilities that are seeking to deploy a Distribution Management System is lack of mature, field-proven vendor products. While numerous demonstration projects are currently underway, most of these projects utilize standalone controllers or SCADA rule-based systems that are simplistic relative to the more sophisticated (and more flexible) DMS model-driven solutions and heuristic auto-adaptive approaches. Many system vendors offer DMS solutions that are based on these more sophisticated design approaches, but few are mature, field proven products. This report includes information to assist the utility company in identifying and evaluating various vendors.

With increased collaboration of IT and OT, there are potential benefits in harmonizing their standards, guidelines and practices developed in the IT industry. This report explores these potential benefits by examining the key similarities and synergies as well as key differences between IT and OT practices for the design, implementation, operation and maintenance of computer based systems used in distribution control centers. The objectives of this section of the report include bridging knowledge gaps between persons whose background is primarily in electric distribution system operations and persons with background in IT, identifying areas where IT practices make sense in the operations environment and areas where there is not a good fit.

Applications, Value, and Use

This project developed guidelines for dealing with the challenges listed above and numerous other challenges that are detailed in other sections of this report. These guidelines are based on EPRI experience, research, and analysis, as well as lessons learned from various electric distribution utilities and research activities from the academic community. During this project, EPRI conducted DMS workshops and seminars, participated in IEEE working groups on DMS, and participated in various industry forums to discuss issues and challenges facing utilities that are deploying DMS.

These findings are documented in this report, which will serve as a valuable reference manual for electric distribution utilities that are contemplating DMS implementation. Electric utilities should use the results presented in this document to assist in the planning, design, specification, installation, commissioning, and verification of DMS.

Following are the key benefits that members will be able to achieve though this project.

- Members will be able to better plan DMS investments through an understanding of application requirements and performance under different circumstances.
- Members will be able to assess the economics and benefits of different applications as a function of their implementation costs.
- Members will gain valuable insights into the steps needed to plan and procure a DMS, and will also learn about economic justification of a DMS project.

EPRI Perspective

The Grid Modernization Project Set develops and evaluates advanced distribution system applications for reliability improvement, system optimization, asset management, and distributed resource integration. These applications involve implementation of monitoring equipment (sensors), communications infrastructure, and advanced protection and control functions. The program will support utilities in the migration to distribution management systems with model-based management of the system. The DMS of the future will need to integrate many functions to optimize system performance, reduce losses, optimize voltage and var control, improve reliability through system reconfiguration and fast restoration, and integrate distributed resources. The project set builds on the analytical capabilities of the Open DSS software for analytical assessment of advanced distribution management functions and also works with member utilities to demonstrate advanced functions for development of application guidelines and identification of gaps in the technologies.

The project set supports a Distribution Management System Interest Group. This interest group will provide an information sharing forum for development of requirements for DMS implementations, sharing experience from actual implementations, and brainstorming for future applications. Gaps identified will help EPRI in prioritizing future research in this project set.

EPRI views this research as meshing with a number of programs involving advanced distribution system analysis. EPRI personnel have extensive knowledge of this area and personally know key vendor representatives. This has enabled EPRI to receive ready cooperation from most of the vendors of interest.

Future Technical Updates to this report will provide additional guidance on the project implementation activities that follow contract award, such as system design and development, testing and training, installation, commissioning, and sustainment.

Export Control Restrictions

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