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Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

DMS Industry Survey

Energy Systems Division

ANL/ESD-17/11

Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

DMS Industry Survey

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FOUNDATIONAL REPORT SERIES

DISTRIBUTION MANAGEMENT SYSTEMS FOR GRID MODERNIZATION

This is one of seven reports on distribution management systems (DMS), their functions, implementation, and importance for grid modernization.

The reports on DMS in this numbered series of Argonne reports are as follows:

1. Importance of DMS for Distribution Grid Modernization (ANL/ESD-15/16)
2. DMS Functions (ANL/ESD-15/17)
3. High-Level Use Cases for DMS (ANL/ESD-15/18)
4. Business Case Calculations for DMS (ANL/ESD-17/3)
5. Implementation Strategy for DMS (ANL/ESD-17/6)
6. DMS Integration of DER and Microgrids (ANL/ESD-17/8)
7. DMS Industry Survey (ANL/ESD-17/11)

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FIGURES

FIGURES (CONT.)

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LIST OF ABBREVIATIONS

AMI	Advanced metering infrastructure
CIP	Critical Infrastructure Protection
DCC	Distribution control center
DER	Distributed Energy Resource
DERMS	DER Management System
DMS	Distribution Management System
EMS	Energy Management System
FLISR	Fault location isolation and service restoration
GIS	Geographic Information System
IOU	Investor-owned utility
IT	Information Technology
OLPF	Online power flow
OMS	Outage Management System
OT	Operational Technology
RF	Radio frequency
SDWG	Smart Distribution Working Group
SOM	Switching order management
VVO	Volt-VAR optimization

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1 DMS INDUSTRY SURVEY

The trends towards distributed generation in recent years have impacted the electric distribution system. Grid modernization is an answer to mitigating these impacts. Thus, the distribution system is being transformed from mostly manual business processes to computer-assisted decision making with automation. At the heart of this transformation is the Distribution Management System (DMS)—a set of integrated computer and communication systems to assist the distribution system operator, engineers, and other electric utility personnel in monitoring and controlling the distribution system in an optimal manner without compromising safety or asset protection.

This document contains the results of a survey conducted by the DMS Task Force of the IEEE Smart Distribution Working Group (SDWG) in 2016 to identify and document trends in DMS applications by North American electric utilities and to document the results achieved by utilities that have years of DMS operating experience.

2 SURVEY RESULTS

The objective of this survey is to benchmark current practices for DMS implementation to serve as a guide for future system implementations. The survey sought information on current plans to implement DMS, DMS functions of interest, implementation challenges, functional benefits achieved, and other relevant information. These survey results were combined (where possible) with results of similar surveys conducted in the previous four years to observe trends over time.

The survey, comprised of twenty (20) multiple-choice questions, was sent by email to over 300 members of the IEEE PES DMS task force with the permission of officers of the IEEE SDWG. All members of the SDWG have expressed interest in DMS and so the SDWG should not be considered as a random sampling of the industry (i.e., this is not a statistically valid sampling of the industry). Typically, organizations not interested in DMS are not members of this group. Hence, the survey only represents the views of entities that are contemplating DMS. Despite the relatively small sample size and lack of truly random polling, the survey provides valuable insights into issues pertaining to DMS implementation.

While most of the survey responders are electric utilities (76% of responders), the survey also includes responses from other organizations (e.g., academic institutions, research organizations, vendors, consultants). The diversity of responders provides insights possessed by non-utilities. Non-utilities were requested to answer the questions from their own viewpoint of the market, including DMS features and research areas their membership, clients, and partners are asking for. Thus, utilities provided their responses from the user point of view, and vendors (8%) provided their responses from the supplier point of view. It should be noted that there is limited choice of vendors in the DMS domain, and a vendor could be providing DMSs to multiple utilities, so the responses may be skewed towards DMSs provided by a few vendors because of multiple counting.

The survey was conducted with a promise of strict confidentiality, and all responses are treated with anonymity. The results of the survey were presented at the DMS Task Force, IEEE Joint Technical Committee Meeting in January 2017 in New Orleans. Also, results were summarized in a PowerPoint presentation and sent to survey participants.

2.1 SURVEY DEMOGRAPHICS

Seventy-two (72) entities responded to the survey, as compared to 77 in 2015. As seen in Figure 1, most responses (nearly 93%) were received from entities located in North America (USA [57, vs. 58 in 2015] and Canada [10, vs. 13 in 2015]). Five responses were received from participants located outside of North America (in China, Taiwan, and Italy).

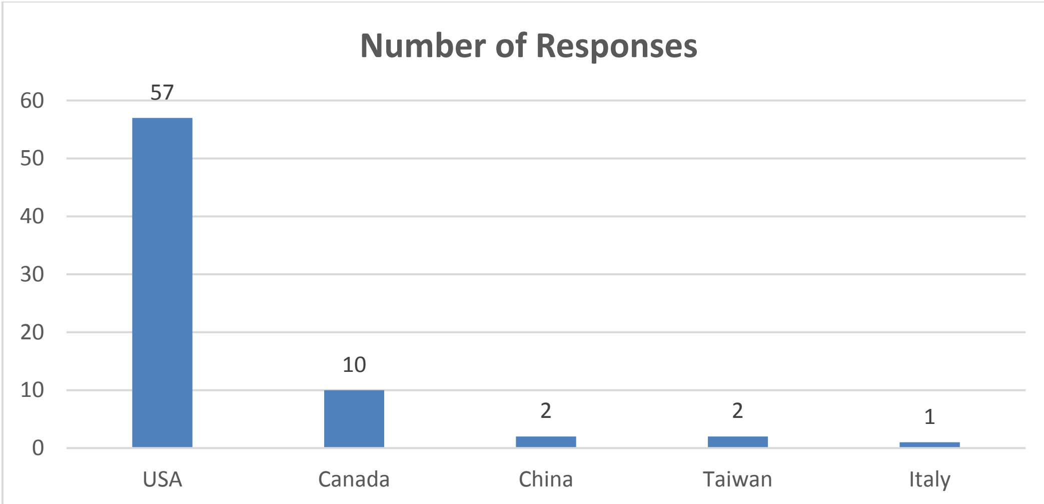

FIGURE 1 Survey Responses by Country

As previously noted, most survey responses (approximately 76%) were supplied by electric utilities of various types, including investor-owned utilities (IOUs), Crown Corporation Provincial Utilities, municipal electric companies, electric distribution cooperatives, and one transmission Limited Liability Corporation that is collectively owned by multiple distribution utilities. Results were also received from vendors, consultants, academic institutions, research organizations, and one government agency. Figure 2 shows the number of responses in each of these categories.

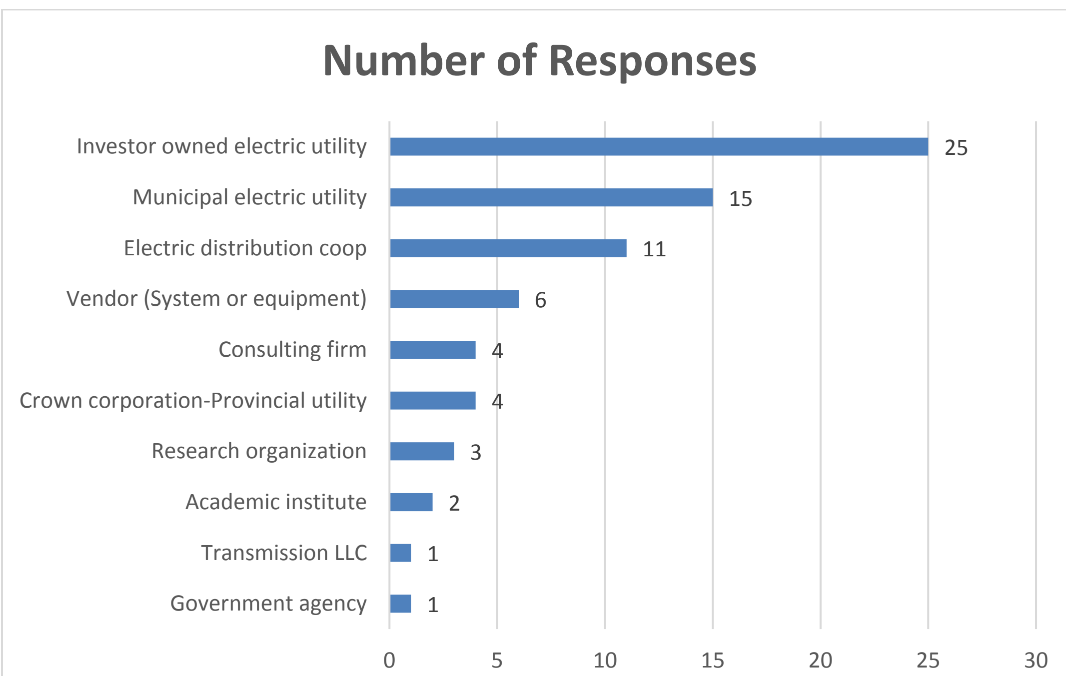

FIGURE 2 Responses by Organization Type

2.2 STATE OF DMS DEPLOYMENT

Participants were asked to select the one choice, among the nine listed below, that best describes their current state of DMS deployment. The ninth choice, “Other,” included space to type in an appropriate description.

- **No plans** to implement DMS
- **Just thinking** about DMS; haven’t yet decided whether to proceed, project on hold
- **Planning stage**, including needs analysis, developing a business case, developing general implementation strategy
- **Procurement stage**, developing detailed specifications, bid evaluation, contract negotiation
- DMS design and test stage
- System installation, integration, and commissioning
- DMS **up and running** and being used for live system operation
- Doing DMS **“mid-life”** assessment
- Other

Figure 3 summarizes the responses to the question about current state of deployment. Sixty-eight (68) out of seventy-two (72) survey participants responded to this question.

The responses show that almost 40% of the survey participants (27 responders) reported that they are in the “thinking about it” or “planning” stage of DMS deployment. This indicates that there is active interest in DMS, with DMS implementations being planned by multiple responders. Electric utilities are gaining valuable experience with the benefits and new opportunities afforded by the implementation of a DMS. At the same time, the maturity being gained by vendor products (thanks to advancement in the Information Technology [IT]/Operational Technology (OT) domain) will simplify future deployments and lower the cost.

Forty-one percent (41%) of the survey participants reported that their DMS is “up and running” (fully operational, partially operational, or undergoing mid-life assessment).

Six of the responses that were entered under the “other” category indicated that responders had gone live with some of the planned DMS applications, but had not yet completed the installation of all applications. It should be noted that utilities implement their system in phases, with early phases including basic functions (SCADA, geographic displays, etc.) and later

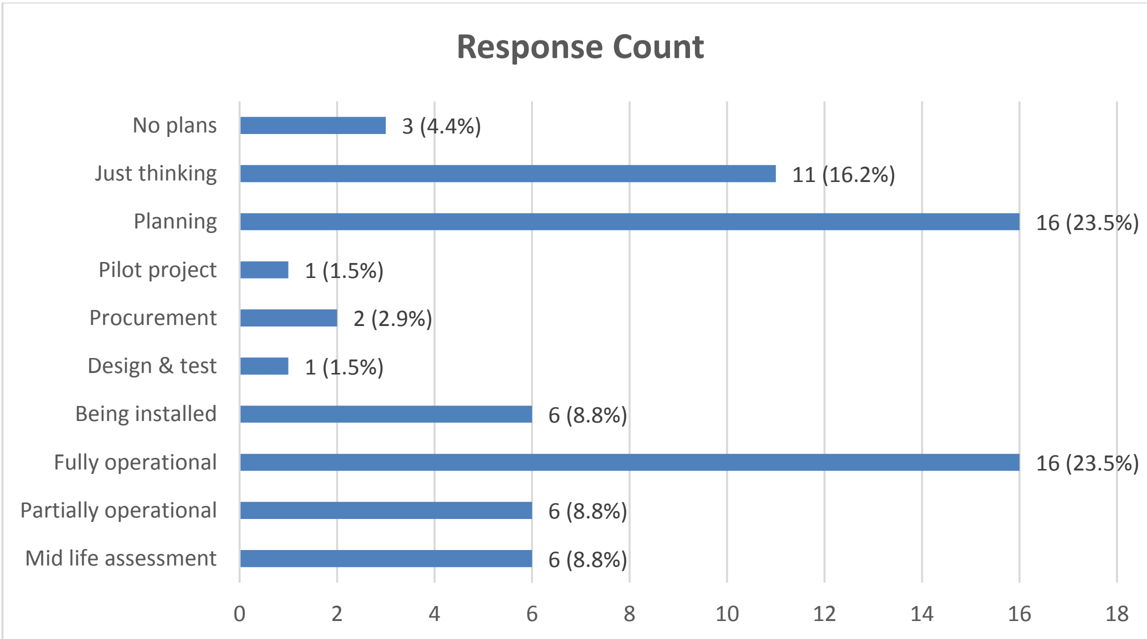

FIGURE 3 DMS Implementation Status

phases including more advanced functions (volt-VAR optimization [VVO], fault location isolation and service restoration [FLISR], etc.). One of the responders reported that Outage Management System (OMS), Mobile Workforce Management, and Mobile Storm Damage Assessment Tools had been implemented, and that DMS and other advanced applications were still at the planning/development or business case stage. Thus, an additional DMS implementation status was added to this analysis: “DMS Partially Implemented.” This possible status will be included as a choice in next year’s survey.

Six responders indicated that they were doing a “mid-life” assessment of a DMS that had been in service for years. Reasons given for this mid-life assessment included interest in incorporating advanced DMS features (combined OMS/DMS; management of Distributed Energy Resources [DERs]). In two responses, it was stated that the original system did not live up to expectations.

2.3 DMS APPLICATIONS BEING IMPLEMENTED

The next survey question asked survey participants to identify the application functions they are implementing or planning to implement in their DMS. Fifty-six (56) out of seventy-two (72) survey participants answered this question. The chart shown in Figure 4 is ordered by the percentage of survey participants indicating that they are implementing the specific application. The four most popular items were OMS, FLISR, VVO, and online power flow (OLPF). These results reflect the continued interest in improving efficiency and reliability within the electric utility community.

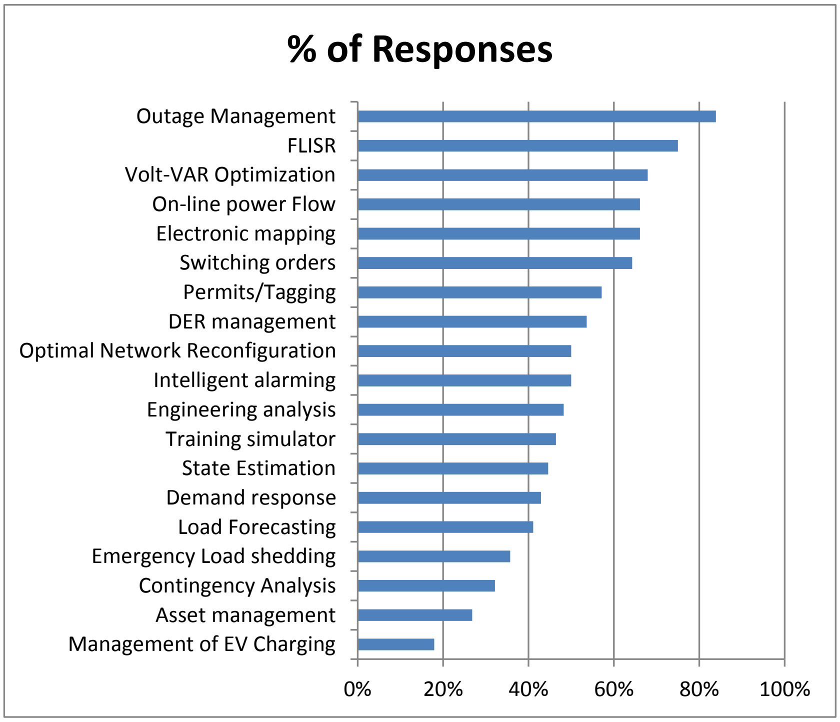

FIGURE 4 DMS Applications Being Implemented

Figure 5 compares responders' 2016 rankings of DMS applications with those of 2014 and 2015. This comparison indicates trends over the past three years in the applications that are most commonly included in the DMS.

Application Rank				2016 Responses	
2014	2015	2016	DMS Application	#	%
6	6	1	Outage Management	47	83.9%
1	1	2	Fault Loc/Isol/Restore (FLISR)	42	75.0%
2	2	3	Volt-VAR Optimization	38	67.9%
10	10	4	Electronic mapping	37	66.1%
3	3	5	On-line power Flow	37	66.1%
4	4	6	Switching orders	36	64.3%
5	7	7	Permits/Tagging	32	57.1%
12	11	8	DER management	30	53.6%
8	8	9	Intelligent alarming	28	50.0%
13	12	10	Optimal Network Reconfiguration	28	50.0%
9	9	11	Engineering analysis	27	48.2%
7	5	12	Training simulator	26	46.4%
11	9	13	State Estimation	25	44.6%
17	15	14	Demand response	24	42.9%
16	16	15	Load Forecasting	23	41.1%
14	13	16	Emergency Load shedding	20	35.7%
15	14	17	Contingency Analysis	18	32.1%
18	17	18	Asset management	15	26.8%
19	19	19	Management of EV Charging	10	17.9%

FIGURE 5 Trend in Most Common DMS Applications for 2014–2016

Three applications moved up by three or more positions compared to the ranking in the 2015 survey (i.e., a higher percentage of utilities were seeking to deploy them in 2016):

- **Outage Management –** OMS functionality moved from the 6th most popular DMS application to the most popular DMS application in 2016. OMS functionality has always been a priority in the Distribution Control Center (DCC); but an industry trend towards combined OMS/DMS functionality is most likely the main driver behind the improved ranking of OMS. An integrated OMS/DMS has benefits in terms of improved operator efficiency (with a single system), reduced data maintenance efforts because of the common database, and an improved outage management process.

- **Electronic Mapping** – Manual, paper-driven business processes for maintaining vital records (including maps) have always been among the most labor-intensive processes in the DCC. The improvement in ranking from 10th to 4th during the past year can be attributed to the potential business process improvement (electronic mapping virtually eliminates the need for hand-drawn updates). Association of map updates with OMS may also explain its popularity.

- **Distributed Energy Resources Management** –As DER (distributed generation, storage, controllable loads) penetration grows, the need to manage these resources effectively from the DCC is also growing. This explains the growing interest in DER management via a DMS.

Figure 6 shows a comparison of the application rankings for the different types of electric utilities that responded to the survey. The total numbers of responses from investor-owned utilities, municipal electric utilities, electric distribution cooperatives, and crown corporations were 19, 12, 9, and 3, respectively. Following are observations drawn from this comparison.

	Investor owned elec utility		Municipal electric utility		Electric distribution coop		Crown Corporation	
DMS Application	**Rank**	**% of Responses**	**Rank**	**% of Responses**	**Rank**	**% of Responses**	**Rank**	**% of Responses**
Outage management	1	60%	1	82%	1	64%	11	67%
Switching order management	2	52%	3	65%	7	36%	4	100%
Electronic map updates	3	48%	2	65%	3	45%	2	100%
Fault Location Isolation and Service Restoration	4	48%	4	65%	2	64%	1	100%
Permits, tagging, clearance management	5	48%	7	47%	8	36%	5	100%
Volt-VAR Control and optimization	6	48%	8	47%	9	36%	6	100%
On-line power flow	7	44%	5	59%	4	45%	3	100%
Management of distributed energy resources	8	36%	14	35%	10	36%	13	67%
Demand response management	9	32%	17	24%	5	45%	16	33%
Intelligent alarm processing	10	28%	6	47%	6	45%	12	67%
Engineering analysis	11	28%	9	47%	11	36%	7	100%
Training simulator	12	24%	10	47%	13	27%	9	100%
Distribution state estimation	13	24%	16	29%	14	27%	10	100%
Optimal Network Reconfiguration	14	20%	11	41%	12	36%	8	100%
Load forecasting	15	16%	13	41%	15	27%	14	67%
Emergency load shedding	16	16%	15	35%	16	27%	17	33%
Asset management/condition based maint	17	16%	18	18%	17	27%	18	0%
Contingency analysis	18	12%	12	41%	18	27%	15	67%
Management of electric vehicle charging	19	8%	19	18%	19	9%	19	0%

FIGURE 6 Application Ranking Comparison by Company Type

- Outage management was ranked highest by all company types except Crown Corporations.

- Electronic mapping, FLISR, and switching order management (SOM) ranked among the top ten for all company types

2.4 DMS BENEFITS ACHIEVED

This survey question requested information on the general types of benefits that have been achieved by survey responders who have already implemented all or part of a DMS. Responders were given a list of potential DMS benefits (see the list below) and were asked to select all that apply to their specific implementation. Survey responders were also given the selection choice “Other” to enable them to enter benefits that were not included in the suggested list.

- Improved reliability of customer service
- Field workforce productivity improvement
- Control center personnel productivity improvement
- Deferred or eliminated significant capital expenditure
- Reduced electrical losses
- Reduced peak electrical demand
- Reduced overall energy consumption (energy conservation)
- Voltage profile improvement
- Power quality improvement
- Enable deployment of condition-based maintenance
- Accommodate growing penetration of DERs
- Enable deployment of grid connected or "islanded" microgrids
- Other (please specify)

Figure 7 shows the percentage of responders who indicated that the specified benefit was achieved by implementing DMS.

DMS Benefit	Response Percent	Response Count
Improved reliability of customer service	68.4%	26
Voltage profile improvement	57.9%	22
Field workforce productivity improvement	52.6%	20
Reduced electrical losses	52.6%	20
Control center personnel productivity improvement	47.4%	18
Reduced peak electrical demand	39.5%	15
Power quality improvement	39.5%	15
Reduced overall energy consumption (energy conservation)	31.6%	12
Accommodate growing penetration of distributed energy resources	18.4%	7
Deferred or eliminated significant capital expenditure	7.9%	3
Enabled deployment of condition based maintenance (CBM)	7.9%	3
Enable deployment of grid connected or "islanded" microgrids	7.9%	3
Response time for outages is immediate	2.6%	1
Additional and more granular monitoring of feeders.	2.6%	1
Small reduction in operation cost.	2.6%	1

FIGURE 7 Benefits Attributable to DMS

The benefits attributed to DMS appear to be aligned with the DMS functions that have been implemented by survey responders. DMS functions that can contribute to each of the benefit categories are listed below (examples are given for benefits that were listed on 50% or more of the responses):

- Improved reliability of customer service; improved customer outage communications:
  - OMS functionality improves business processes associated with response to customer outages, including predicted fault location and crew management.
  - FLISR will restore service rapidly (typically within one minute) to customers connected to "healthy” portions of a faulted distribution feeder.

- Control center personnel productivity improvement:
  - Electronic mapping seeks to eliminate hand-drawn map updates, which represent a time-consuming process for control room operators.
  - SOM will automate many of the business processes that are used by control room personnel to generate switching orders.
  - Training simulators will reduce the amount of senior operator time dedicated to on-the-job training of new system operators.

- Voltage profile improvement:
  - VVO will play a role in ensuring that service delivery voltage is within an acceptable range for all customers under all loading conditions.
  - DER management will help ensure that the output of DERs (including intermittent renewables) does not produce high-voltage or low-voltage conditions.

- Field workforce productivity improvement:
  - Permits Tagging and Clearances streamlines the process of requesting and receiving permits, tagging instructions, clearances, and other safety protection guarantees. This can reduce the amount of time field crews wait for system status.
  - SOM will reduce the time needed to prepare switching orders that are required to enable field personnel to work in a safe and efficient manner.
  - FLISR and Predictive Fault Location will provide more accurate fault locations, which in turn will reduce fault investigation time by field crews.

- Reduced electrical losses, peak demand, and energy consumption:
  - VVO will enable the electric utility to operate voltage regulators, substation load tap changers, switched capacitor banks, and other voltage and VAR control devices to achieve various operating objectives, including reduced losses, lower peak demand, and overall energy conservation.
  - Optimal network reconfiguration will enable the electric utility to identify manual switching actions that can be performed to configure the feeder for minimal losses and overall improved efficiency.

2.5 DMS DATA ACQUISITION AND CONTROL STRATEGY

The decision support and automatic control advanced applications included in a DMS require real-time and near-real-time measurements from various strategic locations throughout the electric distribution system. As a minimum, measurements are required from the following strategic locations:

- Substation end ("head end") of feeder;

- Feeder extremities, including feeder end points that are located furthest from the substation end of the feeder;

- Heavily loaded lateral branches; and

- Locations near midline voltage regulators and switched capacitor banks.

The DMS should be able to remotely control various electric power apparatus (switches, voltage regulators, switched capacitor banks, etc.) as required by the DMS applications being implemented.

Survey participants were asked to identify the ways in which an existing or planned DMS performs real-time data acquisition and control. Participants were asked to identify one or more approaches being used (or planned). The following multiple-choice selections were provided in the survey question:

- **<u>SCADA facilities that are an integral part of the DMS</u>** – That is, the monitoring and control facilities were supplied by the same vendor that supplied the DMS itself.

- **<u>Distribution SCADA system that is separate from the DMS</u>** – The DMS uses continuous monitoring and remote control facilities for the distribution system that were supplied by a vendor other than the DMS supplier. In most cases, distribution SCADA facilities that were in place prior to the DMS project were used. These facilities were interfaced to the DMS through the ICCP of other standard interfaces.

- **<u>SCADA facilities that are part of a separate energy management system</u>** – It is common for equipment located in primary substations (HV/MV) to be monitored and controlled via an existing Energy Management System (EMS) that is primarily used to manage transmission and centralized generation facilities. Utilities that used this approach interfaced EMS and DMS facilities via a secure ICCP link between similar facilities.

- **<u>Advanced metering infrastructure</u>** – Advanced metering infrastructure (AMI) facilities are used in some cases to supply near-real-time information from customer end points to the DMS applications.

- Other (please specify)

Sixty (60) of the participants responded to this question. The results are shown in Figure 8. Almost 72% of the survey participants indicated that remote monitoring and control would be provided (at least in part) by SCADA facilities supplied by the DMS vendor (an integral part of DMS). It should be noted that over 80% of the survey participants reported that more than one mechanism was used to handle the DMS data acquisition and control requirements.

Almost half (47%) of the survey participants were using (or planning to use) AMI data as a source of near-real-time information for the DMS applications. This finding indicates that the participating utilities are planning to leverage AMI information for operational purposes other than customer billing.

DMS Approach to Data Acquisition and Control	Response Percent	Response Count
SCADA facilities that are an integral part of the DMS	71.7%	43
Advanced metering infrastructure (AMI)	46.7%	28
Distribution SCADA system that is separate from the DMS	33.3%	20
SCADA facilities that are part of a separate energy management system (EMS)	31.7%	19
Direct integration to real-time field devices outside of traditional SCADA	3.3%	2

FIGURE 8 DMS Data Acquisition and Control Strategy

2.6 DISTRIBUTED ENERGY RESOURCES MONITORING AND CONTROL

This section of the survey focuses on the deployment and use of DERs by the electric distribution utility.

2.6.1 DER Monitoring

Survey participants were asked to identify the types of DERs that are currently monitored on a continuous basis. Participants were asked to check all that apply. A total of 63 responses were received to the survey question. The results are summarized in Figure 9.

Monitoring of Distributed Energy Resources	Response Percent	Response Count
Distributed generation (including intermittent renewables)	64.2%	43
Energy storage devices	22.4%	15
Controllable loads (demand response)	25.4%	17
None of the above	26.9%	18

FIGURE 9 DER Monitoring

As indicated in Figure 9, almost two-thirds (64%) of the entities that responded to this question are currently monitoring distributed generation resources that are connected to the distribution feeders. Smaller fractions of the survey participants are monitoring energy storage (22%) and controllable loads (demand response facilities) (25%).

2.6.2 DER Control

Survey participants were asked to identify the types of DERs that are currently controlled by the electric distribution utility. Once again, survey participants were asked to check all that apply. Figure 10 shows the results. Approximately 38% of the entities that responded to this question indicated that they plan to control distributed generation resources. Over one-third of survey participants are managing their demand response loads via the DMS, and 17.6% of responders indicated that they are controlling, or plan to control, energy storage for demand response facilities.

Control of Distributed Energy Resources	Response Percent	Response Count
Distributed generation (including intermittent renewables)	38.2%	26
Energy storage devices	17.6%	12
Controllable loads (demand response)	33.8%	23
Currently evaluating control of storage and solar	4.4%	3
None of the above	41.2%	28

FIGURE 10 DER Control

2.6.3 DER Communications

The survey included questions pertaining to the mechanisms used to handle communications with the DERs located out on electric distribution feeders.

The first question sought information on the general mechanism used to handle communications between a DMS and DERs located at customer sites. Responders were asked to select one or more approaches reflecting their current approach to DER communications. Figure 11 summarizes the responses to this question. Over 85% of the responders indicated that they communicate directly from the DMS to the DERs. One third (33.3%)of the responders indicated that the DMS communicates (or will communicate) with the DERs via a separate stand-alone DER management system (DERMS). A smaller percentage (approximately 19%) intend to communicate with DERs via an aggregator or similar service provider. Some participants—approximately 6.3% of the survey participants who responded to this question—indicated that they are still working out the details for DER communications.

Survey participants were asked to identify the specific types of communication media that are used or will be used to handle communications between the DMS and DERs located in the field. Figure 12 summarizes the results of the responses to that question.

Most survey participants (65.2%) plan to use the available cellular communication facilities for handling communications between the DMS and DERs located in the field. Approximately half of the participants (49.3%) indicated that they will use or plan to use either Ethernet or radio frequency (RF) communication facilities. Smaller percentages of the survey participants plan to use microwave (15%), wireless local network (Wi-Fi, ZigBee) (19%), and/or power line communication (20%).

Approach to Communicate with DERs	Response Percent	Response Count
Communicate directly with the DERs via SCADA faclities	87.5%	42
Communicate with the DER via a DER management system	33.3%	16
Communicate with a DER aggregator/service provider	18.8%	9
Not sure - still planning	6.3%	3

FIGURE 11 General Approach to DER Communications

Communication Media for DERs and IEDs	Response Percent	Response Count
Wireless cellular communication (3/4 G, LET, etc.)	65.2%	45
Ethernet	49.3%	34
RF radio	49.3%	34
Power line communication	20.3%	14
Wireless local network (Wi-Fi, Zigbee,etc.)	18.8%	13
Microwave communication	14.5%	10
Optical Fiber	4.3%	3
900 MHz radio links	1.4%	1
Mesh network	1.4%	1
700 MHz radio links	1.4%	1
Undecided - under investigation	1.4%	1
Not applicable or none of the above	1.4%	1

FIGURE 12 Communication Methods for IEDs and DERs

2.6.4 DMS Communication Infrastructure Functions

Survey participants were queried as to the types of supporting communication functions that are included or will be included in communication facilities used by the DMS. Figure 13 summarizes the responses received to this question.

Functions the DMS communication infrastructure will support	Response Percent	Response Count
Encryption	77.3%	34
Authentication	61.4%	27
Different connection modes (e.g., direct peer to peer ad hoc mode and centralized mode where each unit communicates through an access point	52.3%	23
Quality of service (QOS) support (e.g.,different communication delays for different applications)	47.7%	21

FIGURE 13 DMS Communication Infrastructure Functions

2.6.5 Standards for monitoring and control of DERs

Effort is being expended by various industry standardization groups to identify suitable standards for communicating with DERs. Since the communication mechanism for DERs involves some new monitoring and control functions that are not commonly implemented in traditional power system electrical apparatus (switches, capacitor banks, etc.), there may be a need to develop new standards or to expand on existing standards (such as DNP3 and IEC 61850) to support the evolving needs for DER communications.

Survey participants were asked what standards they plan to implement for monitoring and control of DERs in a DMS. The results are summarized in Figure 14.

Standards for monitoring and controlling DERs	Response Percent	Response Count
SunSpec Modbus	8.5%	5
DNP3	6.8%	4
Smart energy profile (SEP 2)	5.1%	3
Develop custom protocol	3.4%	2
OpenADR	1.7%	1
Mesa	1.7%	1
Not Sure	86.4%	51

FIGURE 14 Communication Standards Used for DERs

Survey participants mentioned a variety of standards for communicating with DERs. Over three quarters of responses (86.4%) indicated uncertainty regarding what standard to use. As DERs continue to grow in popularity in the electric utility community, it is expected that consensus will be reached on the specific communication standards.

2.6.6 Microgrids

This portion of the survey included questions pertaining to the use of microgrids, which are relatively small portions of the electric power grid that can be easily connected to or disconnected from the main portion of the power grid to operate autonomously if so desired. There is growing interest within the industry and utility-regulating bodies in building electric distribution systems capable of operating in island mode (completely separated from the main power grid) or in grid-connected mode. In grid-connected mode, the internal DERs are controlled in a manner that makes the most effective use of these resources.

Figure 15 summarizes the response to a question about the number of microgrids that are currently implemented on the electric distribution system. In 2016, 63 responses were received to this question. Twenty-seven percent (27%) of survey participants indicated that they currently have one or more microgrids on their system. This is higher than the corresponding response from the 2015 survey, which indicated that 17.2% of the participants had at least one microgrid in service.

Seventy-three percent (73%) of the 2016 survey participants indicated that they currently have no microgrids on their system, compared to 83% of survey participants in the 2015 survey. A 10% decrease from year 2015 indicates an interest in microgrid deployment. Of the 2016 survey participants with zero microgrids, 27% are expecting to have one or more microgrids in the future.

How many micro-grids do you currently have in your system?	2016		2015	Trend in 2016
Current Number of Microgrids	**Response Count**	**Response Percent**	**Response Percent**	
Zero, and do not plan to have any	29	46.0%	37.9%	Higher % do not plan to have microgrids
Zero, but plan to have more	17	27.0%	44.8%	Lower % plan to have more microgrids
One	7	11.1%	6.9%	Higher % currently have one or more microgrids
More than one	10	15.9%	10.3%	

FIGURE 15 Number of Microgrids Deployed

Entities that either have or plan to have one or more microgrids on the system were asked to identify the microgrid functionality they plan to implement. A total of thirty (30) responses were received to this question; Figure 16 summarizes the results. A majority of survey participants indicated that they are planning to deploy both island operation and grid-connected applications.

What functions do you plan to implement in the microcontroller?	2016 Responses		2015 Responses	Trend in 2016
Microcontroller Functions	**Response Percent**	**Response Count**		
Islanding operation	96.7%	29	88%	More planned islanding
Grid connected operation	83.3%	25	94%	Less grid-connected mode
Fault detection and isolation	70.0%	21	69%	No significant change
Reclosing to external utility grid	33.3%	10	50%	Less reclosing to main grid
Power quality enhancement, including harmonics unbalance	30.0%	9	25%	Slightly more PQ enhancement
Being investigated	6.7%	2	0%	

FIGURE 16 Microgrid Controller Objectives

2.7 SECURITY – CIP COMPLIANCE

Security is a concern of IT managers and others who are contemplating the implementation of a DMS. Experience in this area has been gained with EMSs that are being used to manage the operation of the bulk power grid, including transmission lines and centralized generation. The EMS and its associated applications and data acquisition and control facilities are, for the most part, classified as critical infrastructure, and are therefore subject to Critical Infrastructure Protection (CIP) compliance.

The question of whether DMS monitoring and control facilities should also be classified as critical infrastructure, for purposes of compliance with the NERC CIP standards, is a matter of debate within the electric utility industry. Entities that are in favor of classifying distribution facilities as critical infrastructure cite the capability of the DMS user to rapidly shed load, including critical loads (hospitals, government offices, fire and police facilities, municipal infrastructure such as sewage treatment, etc.). Integration of DMS with other IT systems that are generally classified as business-related is a factor that complicates the conversion to a CIP-compliant facility.

Survey participants were asked to indicate whether they considered their DMS facility to be a CIP-compliant facility. The results are shown in Figure 17.

Slightly less than half (48%) of survey participants are currently uncertain as to whether their proposed DMS facilities are CIP-compliant. However, the level of uncertainty about CIP compliance was lower in 2016 compared to 2015. A higher percentage (21%) of survey participants in 2016 (compared to 7% in 2015) indicated that the DMS is completely CIP-compliant. Roughly the same percentages (approximately 20%) of survey participants in both years indicated that portions of the DMS, such as facilities to control substation equipment, are often classified as critical infrastructure. A smaller fraction of the participants (10.3%) declared their DMS as not CIP-compliant.

Extent to which DMS is CIP compliant	2016 Survey Responses		2015 Responses	Trend in 2016
Answer Options	**Response Percent**	**Response Count**		
DMS is completely CIP compliant	20.7%	12	7%	Considerably higher % of CIP compliance for DMS in 2016
Portions of the DMS, such as control of substation assets, are treated as CIP facilities	20.7%	12	22%	Roughly the same
DMS facilities are not CIP compliant	10.3%	6	7%	Slightly more non-CIP in 2016
Not sure at this point	48.3%	28	63%	More certainty in 2016

FIGURE 17 CIP Compliance

The level of uncertainty about CIP compliance for DMS has been reduced over the past year, with a 15% reduction compared to 2015. This level of uncertainty indicates that the industry still needs guidance on how to proceed with CIP compliance issues for this class of system.

2.8 CHALLENGES

This question asked survey participants to identify the challenges that they considered to be significant for utilities that have implemented a DMS or are planning to do so. FIGURE 18 shows a comparison of the challenges identified in 2015 and 2016.

Significant challenge in deploying a DMS	2016 Responses		2015	Changes Observed from 2015 to 2016
	Response Percent	Response Count	Response Percent	
Planning a new system	39.0%	16	25.0%	Significantly higher interest (14%)
Developing the business case	41.5%	17	50.0%	Slightly less interest (8% less)
Preparing detailed specifications	43.9%	18	30.6%	Significantly higher interest (13%)
Soliciting and evaluating vendor proposals	17.1%	7	19.4%	About the same level of interest
System design and test activities	43.9%	18	36.1%	Significantly higher interest (8%)
DMS integration with external systems	73.2%	30	61.1%	Significantly higher interest (12%)
Debugging DMS advanced software	36.6%	15	44.4%	Slightly less interest (8% less)
Installing, testing, and commissioning	41.5%	17	33.3%	Higher interest (8%)
Training and change management	70.7%	29	58.3%	Significantly higher interest (12%)
Determining the benefits (Measurement and Verification)	41.5%	17	38.9%	Slightly more interest (3%)
Leadership to drive utility transformation	2.4%	1	--	N/A
Automatic Real-Time DMS Model updates	2.4%	1	--	N/A
Security of GIS and DMS	2.4%	1	--	N/A
Data readiness	2.4%	1	--	N/A

FIGURE 18 Comparison of DMS Challenges Cited in 2016 versus 2015

In both the 2016 and 2015 surveys, the biggest challenge that utilities have faced in DMS deployment has been system integration (73% in 2016 and 61% in 2015). The DMS requires multiple interfaces to existing corporate computing systems, including geographic information systems (GISs), engineering analysis, AMI, OMS, and others. This activity requires an extensive collaborative effort between IT and OT staff members, the DMS vendor, and possibly an external system integrator. Expenditures on system integration activities can exceed the cost to purchase and configure the actual DMS. Therefore, there is incentive for performing these activities in an effective and efficient manner.

Training and change management is also a concern, as has been the case in past years. Implementing new DMS applications can have an impact on existing business processes, as manual, paper-driven processes are supplanted by electronic computer-assisted decision making. DMS implementation cannot be successful if end users (system operators) are not trained to use the new system software and if well-established business practices are not updated to address this new functionality.

Developing a business case and then verifying that the predicted benefits have been achieved have been another challenge for electric utilities, including those utilities that have responded to the survey. As stated elsewhere in the survey report, DMS projects generally do not proceed at full scale without a business case that shows the benefits predicted to be achieved by implementing the DMS outweigh the costs to deploy the system. Utilities are also facing pressure to demonstrate, after the system has been implemented, that promised benefits have been realized.

A persistent challenge that utilities face in DMS deployment is system integration. The DMS requires multiple interfaces to existing corporate computing systems, including GIS, engineering analysis, AMI, OMS, and others. There is incentive for performing these activities in an effective and efficient manner.

The responses to this survey question will play a role in shaping the activities of the IEEE PES DMS working group. In accordance with the results of the survey, priorities for working group activities will be based on the following:

- First-Tier Challenges
  - DMS integration with external systems
  - Training and change management

- Second-Tier Challenges
  - Determining the benefits (Measurement and Verification)
  - Developing the business case
  - Planning a new system
  - Preparing detailed specifications
  - Performing system design and test activities
  - Debugging DMS advanced software
  - Installing, testing, and commissioning

2.9 ARCHITECTURE FOR DMS AND OMS

Today's electric utilities are showing interest in OMSs, which have synergies with DMSs. Integration of OMS with DMS was listed as a DMS application function by the highest percentage of survey participants. Possible reasons for this trend include the following:

- Both types of systems are operational support tools that are used by operating, engineering, and management personnel throughout the electric utility organization.

- OMS and DMS both require an accurate "as operated" model of the electric distribution. While the modeling requirements for DMS and OMS are different (DMS requires a full "power flow" model that contains topology and electrical impedances; OMS requires connectivity and customer counts), it is essential that common portions of these models be in synchronism.

- Some applications, like SOM, are usually offered by both DMS vendors and OMS vendors. While the DMS version includes power flow-validation of switching steps, the two variations of the applications are very similar.

Because of the commonalities listed above, a key industry trend is the combination of OMS and DMS functionality in a single platform.

Survey participants were asked to identify which of the following items best describes their strategy to integrate the DMS and OMS functionality:

- **Separate Systems – No Interface:** DMS and OMS functionality implemented as two mutually exclusive systems that do not share information in a digital fashion.

- **Separate Systems with Digital Interface for Data Sharing:** DMS and OMS implemented on different systems that share data via a digital network.

- **Single System – Separate Models:** DMS and OMS implemented on a single system, but use separate models.

- **Single System – Shared Model:** DMS and OMS implemented on a single system, and a single model is shared by OMS and DMS.

The results are summarized in FIGURE 19. An integrated, single-system approach to DMS/OMS is preferred by the survey participants, with almost 90% preferring a solution architecture that allows the DMS and OMS to be integrated as a single system. Almost 65% of the survey participants expressed a preference for a single platform with a single "shared" model that supports both DMS and OMS applications (referred to in this document as a "combined DMS/OMS"). This is up from last year's results, which showed 52% of survey participants using or planning to use a combined DMS/OMS architecture. Survey participants that use separate systems for DMS and OMS often do so because an existing legacy OMS cannot be expanded to include the required DMS application functions, or because an existing DMS does not support OMS functionality. When determining a suitable strategy for DMS, the need for OMS functionality and associated cost should be carefully examined and considered during vendor selection.

	2016 Results	
General Architecture for DMS/OMS Architecture	Response Percent	Response Count
DMS and OMS are implemented on a single system, and a single model is shared by OMS and DMS	64.8%	35
DMS and OMS are implemented on a single system, but separate models used by OMS and DMS	24.1%	13
DMS and OMS on separate systems with separate models	7.4%	4
Not sure - still under investigation	3.7%	2

FIGURE 19 Approaches to DMS/OMS Integration

2.10 OPEN SOURCE DMS PRODUCT

The 2016 survey included two questions pertaining to the availability of an "open source" DMS product. Over two-thirds of survey participants (68%) either skipped this question or selected a "Not Sure" response. Thus, the responses to these questions are generally inconclusive. From the vendors' perspective, an open architecture will impact their business, and from the utilities' perspective, they would not like their system architecture to be exposed.

The responses to the questions about an open source DMS are summarized below.

- **Question 1: "**What value (if any) would you place on having an industry standard DMS that was open source? (Check response that applies best.)" (See answer summary in Figure 20.)

What value (if any) would you place on having an industry standard DMS that was open source? (Check response that applies best)		
Summary of Responses	**Response Percent**	**Response Count**
Extremely high value	2.8%	2
Very High Value	2.8%	2
Some Value	15.3%	11
Minimal Value	8.3%	6
No value at all	2.8%	2
Not sure	23.6%	17
Skipped question	44.4%	32

FIGURE 20 Value of Open Source DMS

As seen in FIGURE 20, 44% of the survey participants skipped this question or selected "Not Sure." Four of the 23 participants who provided a specific response to the question indicated that open source DMS has high value. Seventeen of the 23 indicated that open source DMS has some value. The remainder indicated that open source DMS has no value at all.

A sample of comments received in response to this question are shown below:

– "Developing an open source DMS is not practical."

– "Need to clarify meaning of open source DMS. Is this 'free' software? Who would configure, maintain, and support this?"

– "Developing open standards for advanced applications and interfaces makes sense. But why would anyone want to re-invent basic DMS functions like HMI that vendors have spent years developing?"

- **Question 2:** "If an open source DMS product was available, which of the following benefits do you believe you would gain from this? (Check all that apply.)" (See answer summary in FIGURE 21.)

Benefits of Open Source DMS	Response Percent	Response Count
More flexibility to add applications in the future	67.2%	43
Lower procurement cost	48.4%	31
Lower integration costs	45.3%	29
Easier to select a DMS vendor	40.6%	26
Lower planning and implementation cost	37.5%	24
Less time spent debugging advanced applications	31.3%	20
Simpler to maintain	31.3%	20
Harder to test & troubleshoot (negative benefit)	1.6%	1

FIGURE 21 Benefits of Open Source DMS

As stated earlier, the responses to this question are generally inconclusive because of the number of participants that skipped the question. However, the comments received do raise some issues that should be resolved prior to making investments in an open source DMS product.

2.11 DEVELOPMENT OF NEW ADVANCED FUNCTIONS FOR DMS

The survey asked a number of questions about the desirability of developing new advanced applications for the DMS.

2.11.1 Distribution State Estimator

Advanced state estimation algorithms that take advantage of redundant measurements are standard for EMSs used on transmission systems. However, DMSs usually rely on simpler (and presumably less accurate) techniques such as bus load allocation and historical load profiles. The survey included the following question: "What value would you place on having a practical DMS state estimation application that uses all available measurements (including AMI data)? (Please select one choice.)" Survey results are summarized in FIGURE 22.

Value of Distribution State Estimator	Response Percent	Response Count
Extremely high value	18.8%	12
High value	31.3%	21
Valuable	29.7%	19
Some Value	17.2%	11
No value	1.6%	1

FIGURE 22 Value of Distribution State Estimator

The survey results indicate that the nearly all of participants (98.4%) believe the state estimation application would provide value. One survey responder offered the following caution about using AMI data in SCADA applications: "Timeliness in very large scale can be a challenge. It can tax the AMI network, but getting data through MDMS to DMS can slow in large scale."

2.11.2 Distribution Contingency Analysis

Transmission EMS systems continuously perform contingency analysis to identify plausible asset failures that could have adverse consequences so that system operators can be proactive in mitigating the potential consequences.

The survey included the following question: "What value would you place on having a practical DMS contingency analysis application? (Please select one choice.)" The survey results indicate that nearly all the participants (97%) believe the distribution contingency analysis application would provide value. Survey results are summarized in .

Value of Distribution Contingency Analysis	Response Percent	Response Count
Extremely high value	7.7%	5
High value	32.3%	21
Valuable	40.0%	26
Some Value	16.9%	11
No value	3.1%	2

FIGURE 23 Value of Distribution Contingency Analysis

3 Summary of Survey Findings

This section summarizes the responses to the DMS survey questions.

- Demographics – Most responses were received from North American IOUs (35%). However, the survey participants included municipal utilities (21%), distribution cooperatives (15%), and Crown Corporation utilities (6%), as well as vendors (8%), consultants (6%), academic institutions (3%), and research organizations (4%).

- Current state of DMS deployment – Over one-third (41%) of utilities have at least partially deployed a DMS, and therefore, available DMS products are becoming more mature and field-proven. The same percentage of electric distribution utilities (41%) are considering a DMS or identifying the planning stages for the deployment of such a system.

- Outage Management, FLISR, VVO, and OLPF are among the most popular functions being considered for deployment. This is mainly because by deploying these functions, the utilities can improve their operational efficiency and reliability. There is also a growing interest in electronic mapping (a six percentage point increase from 2014 and 2015) and DER management (four and three percentage point increases from 2014 and 2015; respectively).

- An integrated approach to DMS/OMS is preferred by most survey participants, with over 80% preferring a solution architecture that allows the DMS and OMS to exchange data in digital fashion.

- Specific benefits identified in the survey that have been achieved by deploying a DMS include:
  - Control center personnel productivity improvement (53%)
  - Voltage profile improvement (58%)
  - Improved reliability of customer service; improved customer outage communications (68%)
  - Field workforce productivity improvement (53%)
  - Reduced electrical losses (53%), peak demand (40%), and energy consumption (32%)

- Almost three-quarters (72%) of the survey participants indicated that remote monitoring and control would be provided (at least in part) by SCADA facilities supplied by the DMS vendor. Over 82% of the survey participants reported that more than one mechanism was used to handle the DMS data acquisition and control requirements.

- Almost half (47%) of the survey participants were using (or planning to use) AMI data as a source of near-real-time information for the DMS applications.

- Sixty percent (60%) of survey participants indicated that they plan to monitor and control DERs. These utilities plan to control distributed generating resources; 22% plan to control available energy storage and 25% plan to control controllable loads (demand response).

- More than 85% of the responders indicated that they plan to communicate directly from the DMS to the DERs. One-third of the responders indicated that the DMS communicates (or will communicate) with the DERs via a separate stand-alone DERMS. Equal percentages of the participants indicated that they will use, or plan to use, either Ethernet (49%) or RF (49%) communication facilities for this purpose.

- While most participants (86%) were not sure about the standards for monitoring and controlling DERs, those who were sure responded in favor of Modbus (9%) and DNP3 (7%) as their communication standards of choice. This finding is most likely due to the basic familiarity of the electric utility industry with these established communication standards. As new DER-specific standards continue to be developed, it is expected that they will grow in popularity.

- Most survey participants (54%) indicated that they either have or plan to have one or more microgrids. Over three-quarters (more than 80%) of survey participants indicated that they are planning to deploy both island operation and grid-connected applications. The most popular microgrid application is fault detection and isolation (70%), in which the microgrid may be converted to island mode upon loss of the supply from the main electric utility.

- Most survey participants (over 50%) are currently uncertain whether their proposed DMS facility should be CIP-compliant. Some utilities (approximately 22% of the surveyed participants) indicated that portions of the system, such as facilities to control substation equipment that is classified as transmission, are often classified as critical infrastructure.

- Training and change management is also a concern (for 71% of responders), as it was in 2015 (58%). DMS implementation cannot be successful if end users (system operators) are not trained to use the new system software and if well-established business practices are not updated to address this new functionality.

- Development of a practical distribution state estimator and a practical distribution contingency analysis application was viewed favorably by survey participants.[1]

The survey is a cross-section of the industry with participation from multiple stakeholders including utilities, vendors, academic institutions, and government agencies.

[1] Although most of the DMS vendors have a state estimation function, these functions are not fully utilized, mainly because of a lack of available field measurements to run the state estimators. As monitoring distribution systems increase with the deployment of smart meters and DERs, the estimator will be a key function and will have practical use.

The survey captures the needs of these diverse stakeholders and documents the growing interest in DMS and its associated functionalities. While DMS, OMS, and SCADA are currently separate entities in the industry, there is indication that responders favor the integration of OMS, DMS and SCADA into a single system.

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