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Operational Benefits of Advanced Metering Infrastructure

Louisville Gas & Electric – Kentucky Utilities Use Cases

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EXECUTIVE SUMMARY

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PRIMARY AUDIENCE: Distribution operations managers

SECONDARY AUDIENCE: System integration managers

KEY RESEARCH QUESTION

Advance Metering Infrastructure (AMI) systems have been deployed throughout the electric utility industry with capabilities to accurately record and transmit the metered usage of electricity. However, these AMI systems have different capabilities associated with supporting use cases related to operations.

RESEARCH OVERVIEW

This research explores the operations-based use cases supported by the AMI technology planned for deployment at LGE-KU. The document also describes the integration of the AMI system with other distribution systems to enable the use cases deemed valuable.

KEY FINDINGS

- The uses cases that do not require additional development have been proven at multiple utilities.
- The determination of sustained outages can be performed within the meter if properly tuned to the operation of the distribution system.
- Customer Communication systems can deliver quick and accurate outage information based upon AMI reports.
- The utilization of AMI pinging has proven the ability to identify outages that also have an associated down energized conductor hazard.

WHY THIS MATTERS

Understanding how to properly tune the AMI system with other distribution operations data sources enables the realization of many operation benefits.

HOW TO APPLY RESULTS

The use cases listed in the document should be further analyzed by the utility to determine the associated systems capabilities required, the expected value and the development cost for each. Based upon the specific utility's analysis, a development roadmap can be created that outlines the resources need for each use case and a timeline for development and deployment.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- AMI based operational beneficial use cases in production or being considered are often discussed in the Distribution Operations Interest Group (DOIG).

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ABSTRACT

Timely and accurate readings of customers' electricity usage have been the primary basis for the business case that has seen millions of advanced metering infrastructure (AMI) meters deployed, but there are other valuable uses for AMI systems and data. Some utilities have since realized great operational benefits, whereas others have kept the focus on consumption readings.

The utilities that have realized operational benefits have tuned their AMI system to be in sync with their distribution system. The operational benefits have rivaled those provided by supervisory control and data acquisition (SCADA) and the outage management systems. In a short time, distribution system operators have come to rely on the information generated by AMI meters to efficiently process outages, and they use its other operational information. In addition to measuring consumption, the meters have become a valuable sensor located at each customer premise.

The first two sections of this report summarize use cases that have been demonstrated by utility deployments of AMI meters. The first section is dedicated to the many use cases enabled by the simple process of the meter detecting a sustained outage at its point of connection. The second section uses data in addition to outages collected by the AMI meter. The third section describes use cases that require further development from the AMI vendors or vendors of auxiliary systems before the use case can be demonstrated.

Keywords

Advanced metering infrastructure (AMI)
Kentucky Utilities
Louisville Gas and Electric
Outage management system
Outage messages

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SERVICE RESTORATION BENEFITS FROM ADVANCED METERING INFRASTRUCTURE OUTAGE MESSAGES

Outage messages from advanced metering infrastructure (AMI) meters can create many efficiency managing tasks associated with service restoration. The ability to fully realize the efficiency is dependent on the design of outage determinations to be in sync with the operation of the distribution system and tuning the outage management system (OMS) to work in harmony with the AMI outage messages. A well-designed system can supersede customer calls as the primary method for identifying outages.

Engineering the Outage Reporting System

Although AMI meters' primary goal is to provide individual customer consumption data, the main goal for operations is to accurately distinguish between a momentary outage and a sustained outage. The utility should take great effort to ensure that inaccurate outage determinations do not create an outage prediction within the OMS. The most straightforward and accurate method for accurately distinguishing between a temporary and sustained outage is to program the meters to delay coding an outage as sustained until after the utility's protection system completes all its attempts to reenergize the system. This can be accomplished by adjusting the protection philosophy or by adjusting the outage threshold timer in the AMI meter.

Momentary outages occur when the system's protection and restoration schemes work as designed and either reenergize the system following a temporary fault or isolate permanent faults to the smallest number of customers through protection and restoration systems. The length of a momentary outage depends on the reclose times programmed into protective devices and the time required for automation systems to restore customers from alternative sources. A sustained outage occurs for the customers who lose power and must remain out until the utility acts to enable the customer to have their service restored.

Knowing about momentary outages is beneficial, and the data associated with them are employed in many use cases. But none of the use cases associated with momentary outages requires an immediate response by the distribution system operator (DSO) or a first responder. Thus, collecting data associated with momentary outages can occur with normal meter reading schedules. Sustained outages require the immediate attention of the DSO to manage the restoration of the customers. If the AMI, OMS, and supervisory control and data acquisition (SCADA) systems are designed to work together to identify sustained outages, restoration processes and customer outage communication can be greatly improved.

Outage Identification

The process to determine that an outage occurred is the same for most communication technologies, with just a few variables. The first variable is the **outage threshold** in the meter metrology portion of the meter. The outage threshold is the dip in voltage that will cause the power supply to the communication module to drop out. The outage threshold is usually expressed as a percentage of nominal voltage. Table 1-1 displays outage thresholds for Georgia Powers' deployed meters. The second variable is the **sustained outage threshold**. The sustained outage threshold is the duration for which the communication card experiences a loss of power from the meter before the meter transmits an outage event message. The outage threshold varies by meter manufacturer.

Table 1-1
Georgia Power outage threshold table for meters deployed

Form	Nominal Voltage	Sensus Gen2		L+G Focus AX		Elster A3	
		Detection Voltage	%	Detection Voltage	%	Detection Voltage	%
1S	120	–	–	84	70	–	–
2S	240	36	15	168	70	48	20
4S	240	48	20	–	–	–	–
9S	120	–	–	84	70	48	40
12S	120	–	–	84	70	–	–
16S	120	–	–	84	70	36	30

Notes:

All meters programmed with a six-cycle (minimum) delay when voltage drops to levels shown in table.

Nominal voltages selected based on meters primarily in use on our system.

In many meters, the outage threshold is a function of the design of the power supply, located in the metrology portion of the meter, and is a variable that cannot be changed. But the sustained outage threshold is calculated by the software. In many systems, the sustained outage threshold is configurable within the limits of the stored energy within the meter.

For early models of AMI, the capability of the stored energy to power the communication module was just a few seconds. Modern AMI meters have an internal capacitor or batteries that can keep the meter operating for a couple of minutes to many minutes. For AMI systems with a couple of minutes of stored energy, the sustained outage timer is a variable that can be manipulated to match the operation of the distribution system.

Determining Sustained Outage Threshold

Because the meter reset voltage is not maintained during the reclose attempts, the reclose times must be added together to get the total time to lockout. For example, a feeder breaker with a 3-second, 15-second, and 30-second reclose time could have a successful restoration 48 seconds after the start of the event. For this example, to be conservative, the sustained outage threshold should be set greater than 48 seconds so that only outages lasting longer than 48 seconds will be coded by the AMI system as sustained. Setting this wait time too low will result in some momentary outages being reported as sustained outages. Setting the sustained outage threshold too long will reduce the amount of time that the AMI system has to send data packets. For large outages, the reduction in transmit time might result in fewer outage events making it to the OMS. If reclosing times are consistently applied throughout the utility, the wait time can be set close to the sum of the reclose times.

The balance between accuracy and speed is of great concern. If a momentary outage is reported by the AMI system as a sustained outage, the DSOs will process the outage as sustained without any benefit.

Undesired Outage Message Filters

An effective outage reporting system should filter undesired sustained outages before they are passed to the OMS or filter the messages within the OMS. Filtering is often performed outside of the OMS and meter management system by a standalone application. This application will need to access data from multiple systems to identify messages that should be blocked from entering the OMS or identifying messages that might need to be differentiated within the OMS.

Meters with Active Work Orders for Their Location

Blocking the outage message for meters that have an active work order prevents outages from being reported on meters that are experiencing an outage due to normal work activities. This filter works very well for meter orders. Work that involves deenergizing a transformer is usually associated only with one of the many meters attached to the transformer. Thus, a crew will need to contact operations before deenergizing a transformer that is serving multiple customers because only one meter can be filtered out. Active work orders can also be scripted to block outages from all the customers connected to the same transformer as the meter identified by the work order. Because knowing a crew's work location benefits the DSO, having crews call before deenergizing a transformer is a good practice. If the DSO's workload allows, the DSO can allow the outages to migrate into the OMS and then verify that only the transformer involved is predicted and that all the meters associated with the transformer report an outage. Based on the outage information, the DSO can then take action to correct the model of any misassociated meters.

Inactive Meters

Meters that are inactive might have a filter that blocks their message, or the outage in the OMS might be marked as inactive. When responding to a single meter outage associated with an inactive meter, the inactive flag allows the operator to inform the first responders that the service is inactive. There have been cases where a crew responding to an inactive meter outage arrives to find unauthorized individuals removing the service conductors. There is also the option to completely filter out events associated with inactive meters. However, completely filtering them out could leave a hazardous situation for the public, such as an energized overhead service that has been torn from the house of an inactive account.

Meters with an Active Tamper Alert

Some meters report both an outage and a tamper alert together when the meter is removed. Outage events associated with a tamper event are generally blocked from the outage process. The tamper message is still sent through the tamper response process.

Meters That Do Not Reliably Distinguish Between Sustained and Momentary Outages

If a utility has a mixture of meters where some (usually an early vintage) do not accurately distinguish between sustained and momentary outages, that utility might choose to pass outage information only from the meters that can distinguish between the different outages. Filtering the early-vintage meters reduces the need for more complicated filtering applications.

Meter Ranges

When a filtering system is designed, it is a common practice to have a filter based solely on the meter number or a range of meter numbers. This allows the utility to filter out a vintage of meters or meters that are used for alternative purposes.

Single Customer Outages

Single customer outages are often filtered out in areas that have electricians who are permitted to remove meters to work on customer's facilities. Although this practice reduces truck rolls to planned customer outages, filtering these outages also keeps single customer outages from being reported. Some utilities have applied this filter only during normal business hours. During hours when electrician work is not common, the single customer outage events pass to the OMS.

Single customer outages inherently have different investigation techniques. Many events will require the first responder to enter the customer's property. To protect the first responder from startling a homeowner, utilities have initiated additional work processes for dispatching single AMI-only events (customer does not call). The business rule may include the requirement that the customer be contacted to make them aware that a crew will be investigating. Another option is to dispatch someone to inspect the transformer and service from the street without trespassing on the customer's premises until contact is established.

Picking the Meter with the Desired Outage Threshold Voltage

In many meters, the voltage threshold is a function of the hardware and is not a variable that can be changed. Depending on the segment of the distribution system to which the meter is connected, a higher dropout voltage might be desired. In particular, identifying blown fuses on delta-wye transformers and outages associated with ungrounded systems is best supported by a high dropout voltage. For meters with a programmable voltage threshold, the voltage threshold can also be manipulated to provide the optimum outage detection. Following are two scenarios that will be reported as an outage for meters with a high threshold voltage but will not be reported as an outage if the voltage threshold is low. It should also be noted that many polyphase meters monitor the voltage on only one phase and will not report an outage for some single-phase conditions.

Identifying Blown Substation High-Side Transformer Fuses

Many substations use fuses to provide transformer protection. If the transformer is also a delta-wye configuration, a single blown high-side fuse will cause low voltage on two phases of the distribution system. The phaser diagram is shown in Figure 1-1. A blown fuse on Phase 2 of the substation transformer will affect the voltage on phase B and C of the distribution system. Because Va + Vb + Vc = 0 and Va is nominal, the voltage at the meter for customers connected to phase B or phase C will be nearly 50% of nominal.

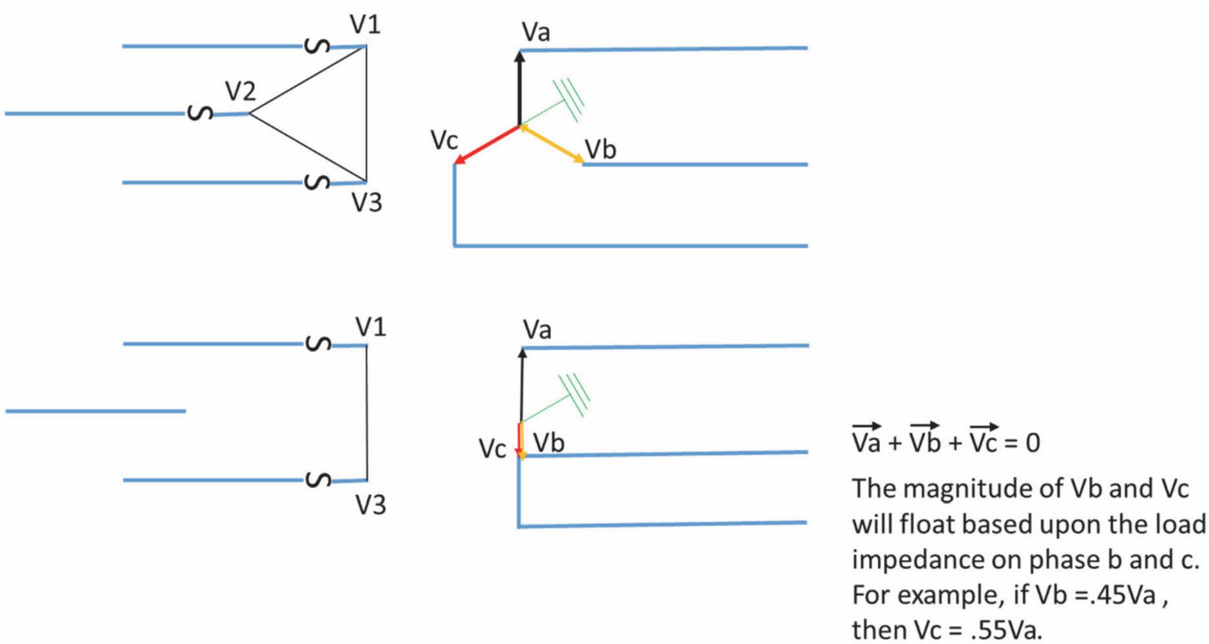

Figure 1-1
Vector representation of high-side transformer fuse open

Because the outage threshold for meters is different for different makes and models of meters, some meters might report an outage while other meters report on a low-voltage alarm. If outages are reported, the OMS will create a predicted outage on the feeder breaker. The DSO will be prompted to investigate.

If low-voltage AMI alarms are not imported into the OMS, the distribution system operator might not know about the condition until customers call. If customers report dim lights to a customer service agent, the agent might create a power quality report instead of an outage report.

Identifying Outages on Ungrounded Distribution Systems

Ungrounded distribution systems might also have a reduced voltage instead of a complete voltage collapse. By selecting meters with a high outage voltage threshold, the meters will report an outage for phases that are being back-fed through transformer windings from the unfaulted phases.

OMS Impacts

The OMS functions by using many prediction rules. Although these rules were created to use a small number of customer calls to create an outage association, the same rules can be used with mass outage reports from AMI meters. But there is some additional functionality created by the predictable speed at which AMI can report outages.

Identifying Nested Outages by Locking Outage Predictions

AMI has the potential to identify nested outages. As AMI outage reporting continues to get faster and more accurate, OMS prediction rules can be adjusted to take advantage of the speed and quantity of outage reporting. One such OMS rule is the time in which outages are locked and prevented from being associated with a larger outage. For example, if the time to lock the outage is set at 5 minutes, a fuse outage that occurs at least 5 minutes prior to an upstream recloser lockout would be locked in as a nested outage. Events that are locked will be identified to system operations as a separate event from the larger event.

In severe weather events when multiple faults are occurring near each other, AMI meters could be reporting outages within proximity of time. Although it is possible to compare the outage start times of AMI outage messages to identify nested outages, this computation is not commonly pursued because field crews are expecting multiple cases of trouble and require a manual inspection of the entire line before energizing. These inspections include the reporting and modeling of open protective devices before closing source devices to restore service.

Outages Restored by FLISR Systems

Outages restored by FLISR (*FLISR* stands for *fault location, isolation, and service restoration*) systems pose an additional challenge for AMI systems. Figure 1-2 illustrates an outage associated with a FLISR restore. In this example, an outage threshold of 60 seconds would report an outage to the OMS, and an outage threshold of 120 seconds would accurately report the outage as a temporary outage.

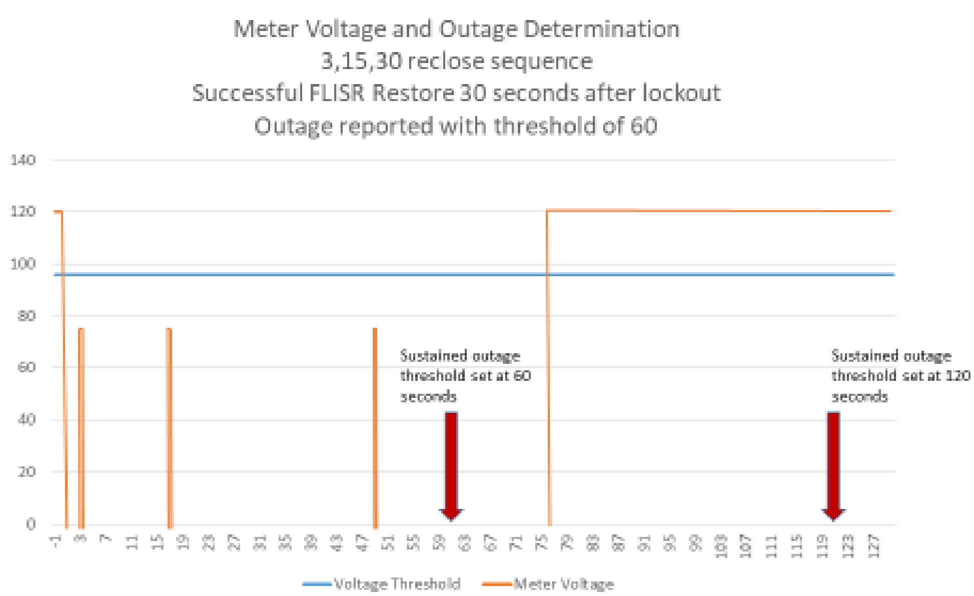

Figure 1-2
Determining outages restored by FLISR systems

Because many AMI systems will have a shorter outage threshold than the total restoration time of most automated FLISR systems, this type of outage will be reported by the AMI meters as sustained. As long as the actions taken by the automatic FLISR application are modeled in the OMS in the correct order, the OMS should predict an outage, create a nested outage, and then close the outage event for the areas restored by the FLISR actions.

Because the FLISR action could occur very close in time to the meters reporting their outage, the AMI outage messages might impact the outage management system by creating a prediction to an area that has just been restored. Prior to AMI, buffered messages from voice response systems created the same issue within the OMS. To prevent restored areas from being predicted out, OMSs have a time delay setting that will group outage messages with restoration activities. For example, in Figure 1-3, within 5 minutes of restoration occurring, any outage messages from customers or meters that come in from the restored area will be auto-closed.

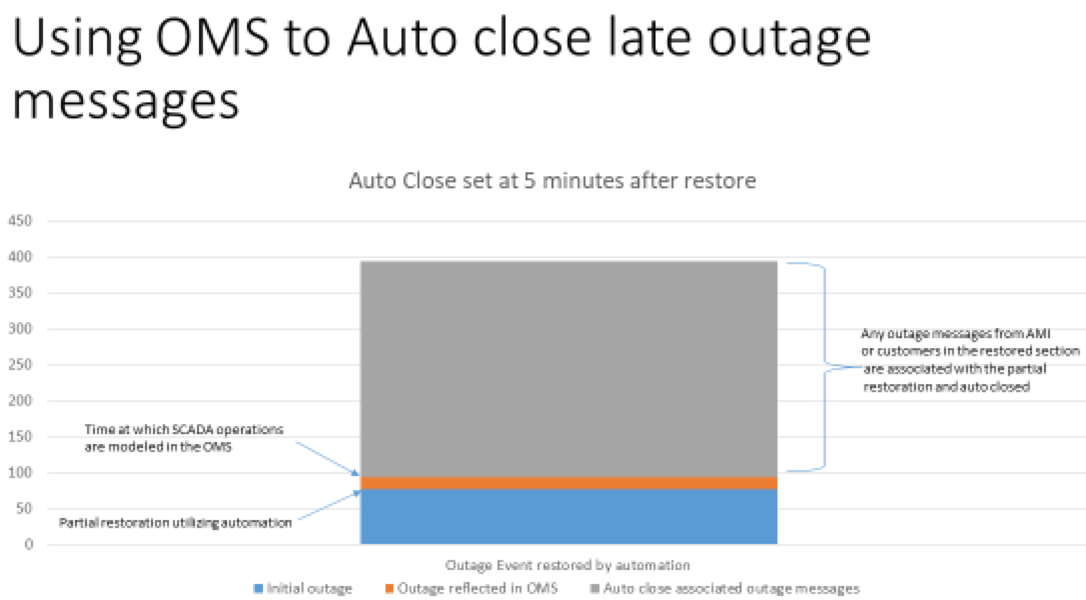

Figure 1-3
Using OMS to close FLISR restored outages

Linking Meters to a Transformer and Capturing the Latitude and Longitude

When the geographic information system (GIS) became the source of information driving the OMS to create predictions, a relationship between the meter account and the premise ID was created. When an AMI meter is installed, it will inherit the premise ID association. The relationship between the meter and the premise ID is the primary linkage for outage messages to be used by the OMS. If past OMS experience has proven the linkage to the premise ID to be a constant source of misinformation, the cost associated with training meter installers to read GIS maps and verify the correct premise ID association might be warranted. Whereas verifying the premise ID association could require additional training and cost, capturing the meter's global positioning system (GPS) coordinates requires little training and can be built into the tools used by the AMI installers. The association of the AMI meter to its physical location enables many use cases that depend on a visual representation of the data. Depending on the meter, the GPS coordinates can be stored in the meter (ANSI C12.19 standard, Table 6) and transmitted with certain messages. If the meter does not support the storage of GPS data, the GPS data can be stored in a back-office association table and added to various messages during processing.

Visually Showing Customer Calls and AMI Outages in the OMS Map

The OMS will receive both customers' reported outage calls and AMI meter outage messages. The OMS can be configured to distinguish between the different outage messages. The OMS can distinguish the outage type by deploying different icons or using the same icon with different colors. The visualization of outages on the OMS outage map provides the operator with a tool to further analyze the current state of the distribution system. Visually representing outages also enables the operator to look for patterns associated with outage events.

AMI Outage Visualizations Outside of the OMS

In addition to showing AMI outages in the OMS maps, utilities can realize other benefits from displaying AMI-related data on a map using the GPS coordinates of the AMI meter. Some AMI vendors have visualization packages, or the utility can design its own visualization to meet their particular use case.

Business Continuity for a Loss of the OMS

If outages are shown on a map that overlays the distribution system, operators can use the outage information to manually perform the function of an OMS. Ideally, the outages would be removed from the map once AMI restore messages are received from the same meters. This is a very effective backup to the loss of the OMS.

High-Level Storm Management

AMI outage and restore messages overlaid on a distribution system map can be used by distribution executives to monitor the outages and the associated restoration efforts during major events. Outages are typically shown in one color, and restorations are shown in a different color. Although the number of AMI outages does not have a direct correlation to the amount of damage to the distribution system, seeing the restorations in near-real-time will show the progress being made by restoration efforts.

Enhanced Customer Outage Information

Many customers expect today's utility to know about their outage and communicate information to them about it without the customer taking any action. Without AMI outage reporting, utilities are able to meet this expectation for outages only behind SCADA-monitored equipment. Without AMI meters sending outage messages, outages behind devices, such as hydraulic reclosers and fuses, will depend on customers notifying the utility about the outage. An AMI system can report outages quickly and greatly reduce the time it takes to accurately determine the open protective device. When notifications from the customers become unnecessary, the utility can change the way it processes outage information and provide information to the customer in a manner that was not possible before an AMI deployment.

Proactive Customer Communication of an Outage Using an AMI-Driven OMS

Customers desire information about their outage. Once a sustained outage occurs, the customer would like to receive a notification from the utility confirming that the utility is aware of the outage. Utilities with an AMI system that accurately distinguishes between a sustained and momentary outage can meet the customer's expectations by quickly (usually within 90 seconds) communicating with the customer that the utility is aware of their outage. For some, this might be a text message or an automated phone call. Customers who do call the utility can be greeted with recorded messages confirming that the utility is aware of the outage as part of the automated voice response system. Customer service agents will also know that the OMS is already aware of their outage. The notification messages can also include account information, such as the address associated with the outage. This allows customers to know the power status at remote locations, such as vacation properties or vacant rentals.

Customer Main Breaker Issues

If outages from your AMI meters consistently create a prediction in your OMS system before customer calls, your customer communication systems can be designed to give customers messages that accurately reflect the state of their service. If the customer's account does not match an existing outage prediction, the system informs the customer that the utility's analytics does not indicate that the customer is experiencing an outage and that they should check their main breaker or contact the maintenance department if the meter is associated with a multifamily account. Many customer calls are associated with internal breaker issues. The system can be further advanced by giving the customer the opportunity to have their meter interrogated. The associated meter is pinged for health and voltage. If the ping is successful, the customer would again get the message directing them to check their breaker. If the ping was unsuccessful, the customer would hear a message confirming their outage, and the system would create an outage ticket and a follow-up work order to determine why the meter did not report the outage. If the customer decides to forgo the automated process and talk directly to a customer service representative, the representative has the same information, including instructions on how to reset a breaker.

Outages for Customers with Multiple Accounts

An outage report by phone from a customer with multiple accounts can be difficult to accurately process. Many customers might not know the identifying attributes of their service, such as account number, meter number, or even the address the utility has on file. Once the customer has linked their phone or email to an account, they will receive outage communications for all accounts.

Outages for Large Commercial and Industrial Accounts

Many commercial and industrial (C&I) accounts have advanced meters that have a different communication medium than the standard AMI meter. Many C&I meters were not designed to report power outages. Utilities have found that it is beneficial for large C&I meters to also report outages, even if the meter uses a different communication system or involves a process separate from standard AMI meter outages. The utility might have to invest in a separate metering monitoring system to proactively report outages associated with their larger customers.

Intermittent Service Problems

Many utilities develop special procedures for single customer outages reported only through the AMI system. One step in the process might be to immediately ping the meter. Occasionally, operations will ping a meter associated with a single meter outage that was reported by the AMI meter and receive a ping response that shows that the meter is energized and has good voltage. Meters that ping on are taken out of the outage process and are dispatched to someone who is equipped to study the service to determine what caused the sustained outage determination. Examples include a bad meter, connection issues, or cable degradation. This allows problems to be corrected before they result in an extended outage or equipment damage.

Enhanced Reliability Indices

If the meter adheres to the ANSI C12.19 standard and implements both the outage and restoration events and the history table and/or profile tables, the meter will have a record of every outage and restoration event. Because the record includes a time stamp, the data within the tables can be used to create very accurate reliability indices. The data within the tables can be collected with normal usage data packets. By calculating indices outside of the OMS, the indices are not impacted by erroneous predictions or human error associated with manually entering outage start and restore times. Utilities have successfully transitioned from reliability indices calculated from the OMS, which are dependent on accurate modeling and data entry, to indices calculated from the start and stop times from the AMI meters. Note that although not all outage messages from AMI meters make it to the OMS systems, all outage events are kept within the outage tables.

Down Energized Conductor Identification

When an energized conductor breaks and falls to the ground, there is the potential for the impedance of the fault to limit the fault current associated with the event. Because most protective devices detect a fault condition by measuring or reacting to the elevated level of current, faults that have limited fault current might go unrecognized by protective devices and remain energized. The occurrence of conductors that remain energized creates a hazard that has been difficult to mitigate. The Electric Power Research Institute (EPRI) has researched multiple options to identify these hazardous conditions (see, for example, the 2018 EPRI report *Modern Approaches to High-Impedance Fault Detection* [3002012882]). One option is to analyze data from an AMI system to help identify broken energized conductors before a visual inspection occurs.

AMI, Outage Management System, and SCADA Data

The process of identifying down conductors with AMI data was first proven by correlating data from advanced metering infrastructure, OMS, and SCADA. Outages within the OMS are either “predicted” or “confirmed.” For confirmed outages, SCADA or an operator acknowledges that the outage is real. When SCADA data from a recloser indicate that the recloser is open, the OMS system will create a confirmed outage and aggregate all outage reports downstream of the recloser into the outage event. If the SCADA system indicates that a recloser is closed but the OMS collects advanced metering infrastructure outages that exceed the prediction setting, the OMS will create a predicted outage at the recloser. The predicted outage must be analyzed by an operator to determine if SCADA or the prediction engine is incorrect.

Through experience, outage events with a SCADA and an OMS conflict were found to be the result of multiple fuse outages or from having an unintended break in the system. A visual review of the outages proved useful in determining which type of event caused the conflict.

Multiple Fuse Outages

If the number of fuse outages behind the recloser exceeded the prediction rules, the fuses' outages would be combined into one outage event behind the recloser. For these events, the operator would determine which fuses were opened based on their associated outage notifications and create confirmed fused outages within the OMS. The predicted recloser outage would be cleared and transformed into multiple fuse outages.

An Open Point in the Main Line

There are times when a jumper or switch might burn open or a conductor breaks to create an open point in the line. Because manual switches, jumpers, and line segments are not predictable devices within the OMS, the outages behind the open point would be grouped and predicted at the recloser. When these events are visually viewed by the operator, a pattern occurs that is easily recognizable. Because all these events create a type of hazard, the operator is prompted to act. Figure 1-4 is a representation of the visualization tool.

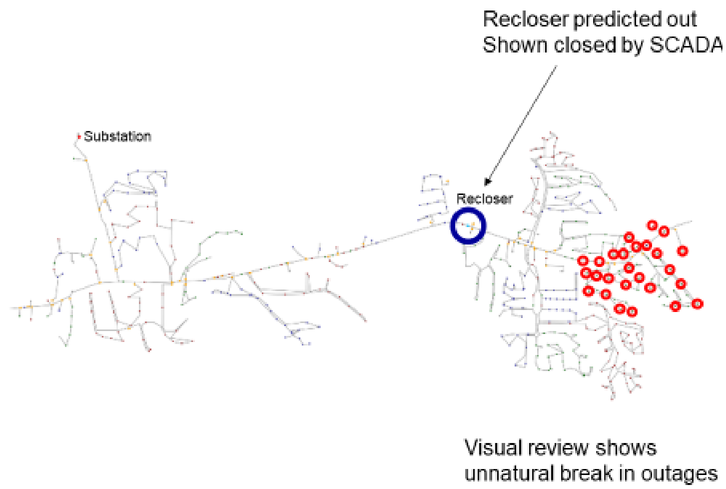

Figure 1-4
Outage pattern of an open point

AMI and OMS Data

The success of identifying down conductors behind SCADA reclosers prompted the investigation of creating an application to identify when AMI data might conflict with an OMS prediction for protective devices without SCADA data. This application is used to identify AMI and outage management system conflicts for outages predicted behind non-SCADA reclosers and fused taps. The process begins by identifying and pinging a meter close to the protective device, known as the *bellwether meter* (see Figure 1-5). Pinging is the act of communicating to the meter with a short, quick message. If the meter does not respond to the ping, the bellwether meter is considered deenergized, indicating that the protective device is open. If the meter does respond to the ping, the meter is known to be energized, indicating that the protective device is closed and in conflict with the OMS prediction. Conflicts between AMI and OMS should be presented to the operator for a review to determine the proper action. Figure 1-6 is a process diagram used by the application that identifies AMI and OMS conflicts.

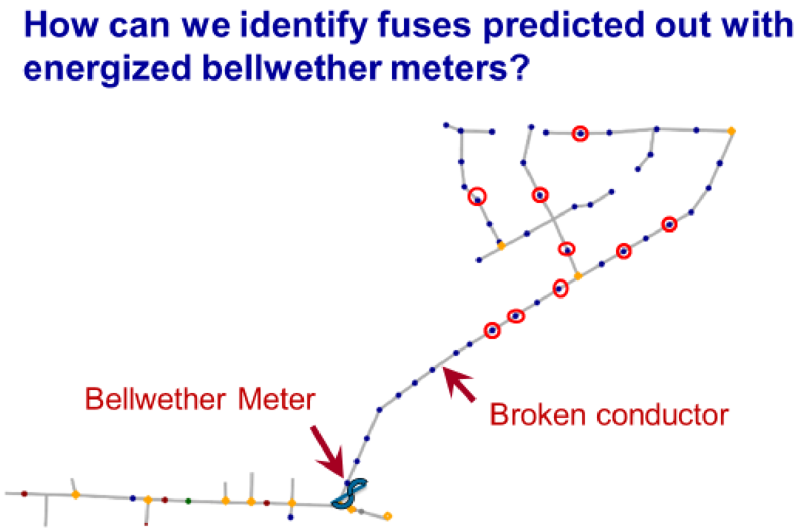

Figure 1-5
Bellwether meters

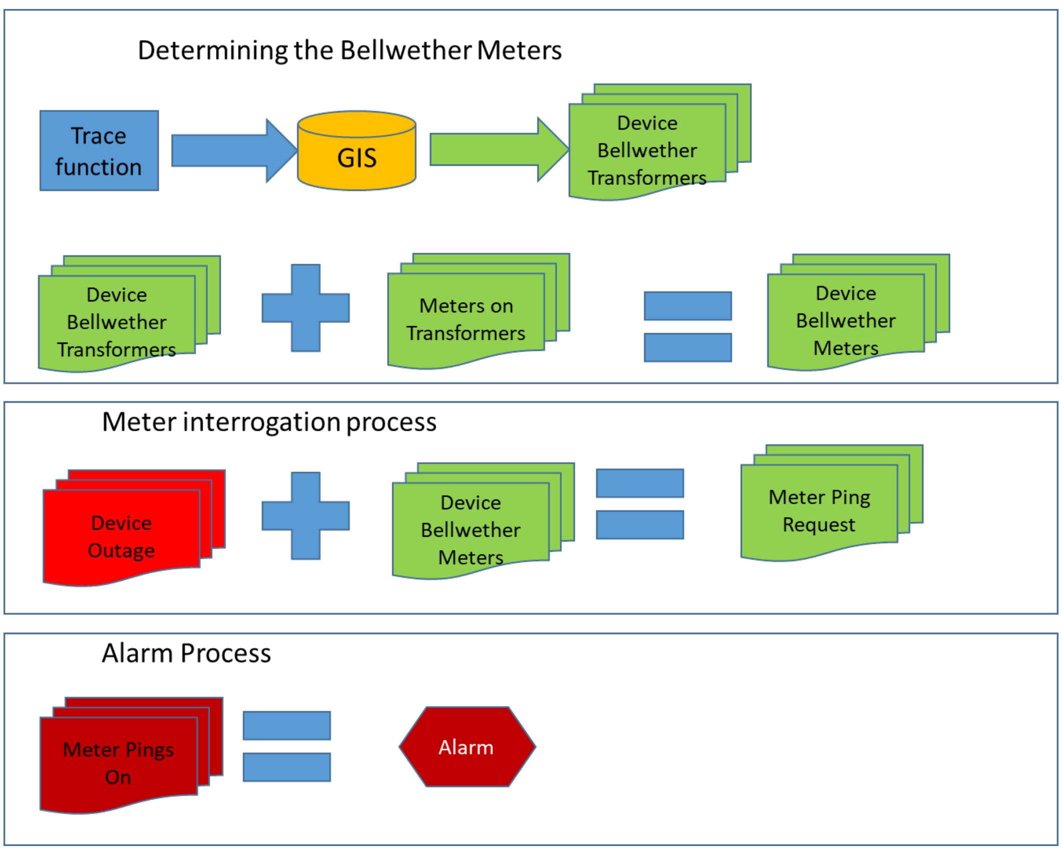

Figure 1-6
Process chart for AMI/OMS conflict identification

Challenges of Delta Systems

Some utilities operate portions of the distribution system without a ground reference. Numerous outages were analyzed on ungrounded systems to determine if the same application could create a visualization of events with a broken conductor. The results were promising. Although events on the three-phase portion of the system can mask the outages, the events associated with only two phases (considered single-phase) could be identified with the same AMI pinging logic (see Figures 1-7 and 1-8). There is a potential to analyze the voltage sags to try to identify a back-feed condition.

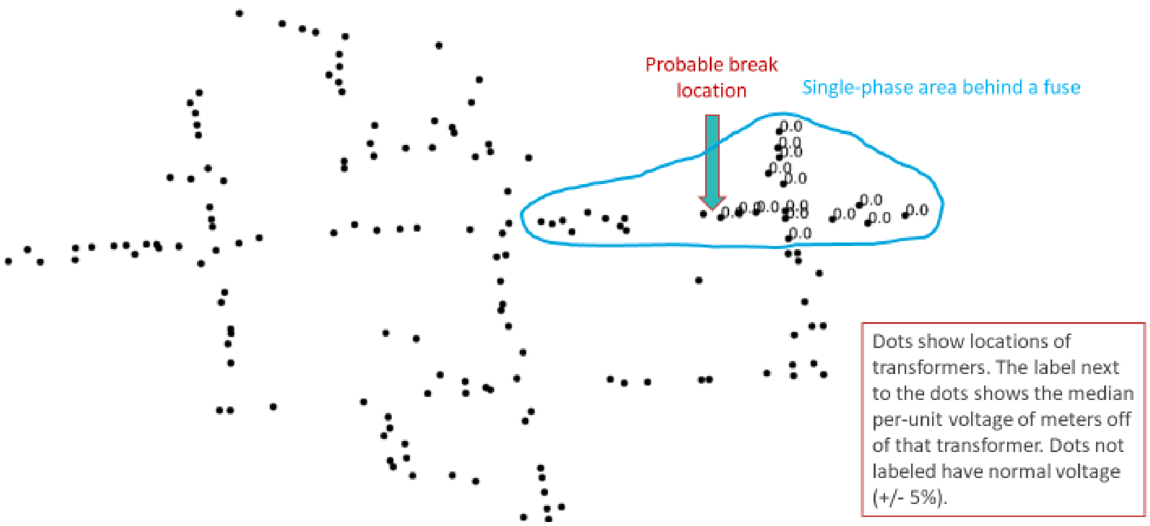

Figure 1-7
Outage event on single-phase delta system

Figure 1-8
Outage event on three-phase delta system

2

USE CASES SUPPORTED BY ANALYZING AMI DATA

A large volume of data within AMI meters is available to operations. Some of these data are used in near-real-time, whereas other data might be collected during normal data collection schedules. In 2012, EPRI tabulated the data captured from a few AMI meters. Table 2-1 lists some of the data available, which vary by meter manufacturer. The data available also vary by the communication module used. In general, using a meter manufacturer that is not the same as your AMI system provider will result in fewer features available. Also noted in Table 2-1 are the intervals available. The interval figure gives the user the range at which other values can be averaged. For example, if you desired 1-minute average voltage, you would not pick meter B1 or E1, which would be able to return only 15-minute averages.

Table 2-1
Parameters provided by sample meters

METER										
Designator	A1	B1	C1	D1	E1	A3	B3	C3	D3	E3
STEADY-STATE PARAMETERS										
Voltage	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Current	✓		✓	✓		✓	✓	✓	✓	✓
Real (kW)	✓	✓	✓	✓		✓	✓	✓	✓	✓
Reactive (kVAR)	✓		✓			✓	✓	✓	✓	✓
Apparent (kVA)	✓					✓	✓	✓	✓	✓
Displacement Pwr Factor	✓			✓		✓	✓	✓	✓	
Total Power Factor			✓				✓	✓	✓	✓
Frequency	✓			✓		✓	✓	✓	✓	✓
Phasors	✓			✓		✓	✓	✓	✓	✓
THD	✓					✓	✓	✓		✓
TDD	✓					✓		✓		✓
Harmonic Quantities	2nd Hrm					✓	Up to 24th	2nd Hrm		Up to 127
Interharmonics										✓
Harmonic Phase Angle										✓
K Factor										✓
Crest Factor										
+/-/0 Sequence										
Flicker										✓
Imbalance						✓				✓
DEMAND										
Real (kW)	✓	✓	✓	✓		✓	✓	✓	✓	✓
Reactive (kVAR)	✓		✓			✓	✓	✓	✓	✓
Apparent (kVA)	✓		✓			✓	✓	✓	✓	✓
Current	✓			✓		✓	✓	✓	✓	
ENERGY										
Watt-hours	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Var-hours	✓		✓			✓	✓	✓	✓	✓
VA- hours	✓		✓			✓	✓	✓	✓	✓
CONTINUOUS TRENDING / DEMAND INTERVALS										
Intervals	1 to 60 Min	15	1 to 60 Min	1 to 60 Min	15	1 to 60 Min	1 to 60 Min	1 to 60 Min	1 to 60 Min	1 second +
Trend Calculations	Max/Min/Avg	Min	Max/Min/Avg	Max/Min/Avg	Min	Max/Min/Avg	Max/Min/Avg	Max/Min/Avg	Max/Min/Avg	Max/Min/Avg
EVENT RECORDINGS										
Text Based	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Oscillograph										✓
Samples per Cycle										Up to 512
TRIGGERS / ALERTS										
Outage					✓		✓		✓	✓
Thresh. Limits (V, I, Harm)					✓		✓		✓	✓
Transients										✓

Transformer Windings Shorts and Regulator Misoperation Identification

Utilities have shown success in identifying failed or failing equipment based on information from AMI meters. Average voltage information can be used to identify transformers with windings shorted and can identify regulators and switched capacitors that are not operating properly. If voltage information is combined with circuit data, the type of problem identified can be scripted, which allows repair orders to be automatically created and dispatched. Voltages that are out of range on a single meter are dispatched as a bad meter. Voltages out of range for multiple meters on a transformer create a repair order to swap the transformer. Voltages out of range for multiple transformers are investigated for regulator or capacitor problems.

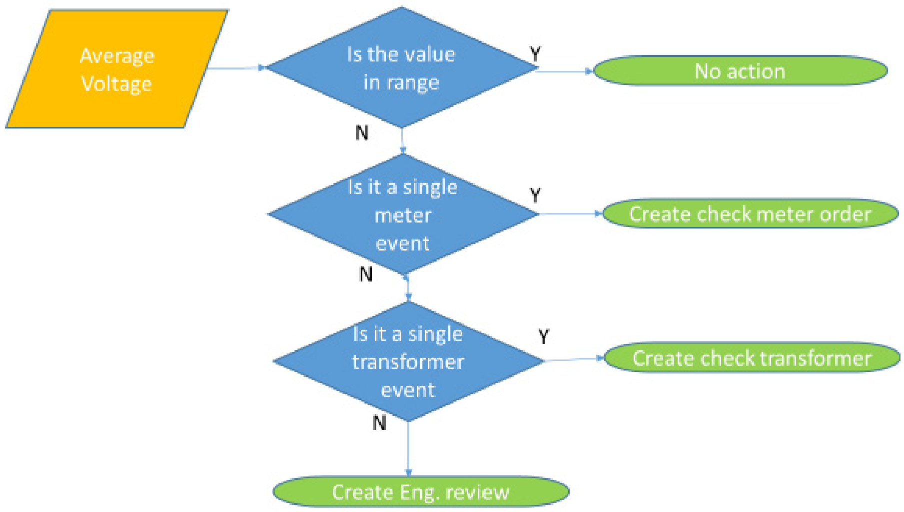

Figure 2-1
Flow chart for sustained voltage out of range

Near-Real-Time Voltage Visualization

If the average voltage of a meter is outside of the normal band but is not low enough to be considered an outage, the meter can be programmed to send the voltage reading to a visualization system. The visualization system resembles a heat map with both high and low voltage readings shown. Once the average voltage is within the acceptable voltage band, the meter again sends its voltage reading and is removed from the heat map. Some meters might be able to perform 1-minute averages, but others are limited to 4-hour averages. The length of time over which the meter averages the voltage depends on the capabilities of the metrology portion of the meter.

Voltage Feedback for CVR Systems

Voltage data from AMI meters can provide feedback to CVR systems. By identifying bellwether meters, the CVR system can ping the bellwether meters after each step-in voltage reduction. If the ping indicates that the voltage is close to the established limit, the CVR system does not perform another step reduction. By using AMI, additional CVR reductions can be realized. Systems that depend on planning studies to determine the amount of reduction are inherently conservative to not create voltage events below the standard limits. AMI meters also account for actual secondary voltage drop. Many planning models estimated a secondary voltage drop. In lieu of selecting bellwether meters, low-voltage alarms can also be monitored by the CVR system to create the low limit of reduction.

Analyzing Feeder Voltage Profile

AMI meters generally report an average voltage, a maximum voltage, and a minimum voltage. The rate at which the data are collected is independent of the time over which the meter calculates the average. The average readings may be minute averages to hour(s) averages. Figure 2-2 presents the voltages reported from a circuit analyzed by Arizona Public Service. Their meters were collecting 1-hour averages; the data are presented each hour over the course of 24 hours. The distance between the data sets in each hour illustrates the range for the meter average voltage across the feeder. Each series represents a group of similarly located meters. The graph in Figure 2-2 highlights the following:

- The series with the lowest voltage becomes the series with the highest voltage during solar generation hours. This might indicate small service wire or undersized transformers at the solar installations.
- Almost all the meters on the feeder exceed the high-voltage threshold when solar panels are generating.
- This feeder does not have substation regulation. To create additional hosting capacity, adding feeder regulation along with capacitor management is being considered.
- Figure 2-2 can also identify areas where the transmission voltage might be high, or the substation transformer could be set on the wrong tap to deliver nominal voltage.
- The data are consistent enough to have a back-office application evaluate the data to identify circuits that are approaching or exceeding voltage limits. The same process would identify circuits with low voltage.
- AMI voltage data alone might be enough to identify individual solar installations.

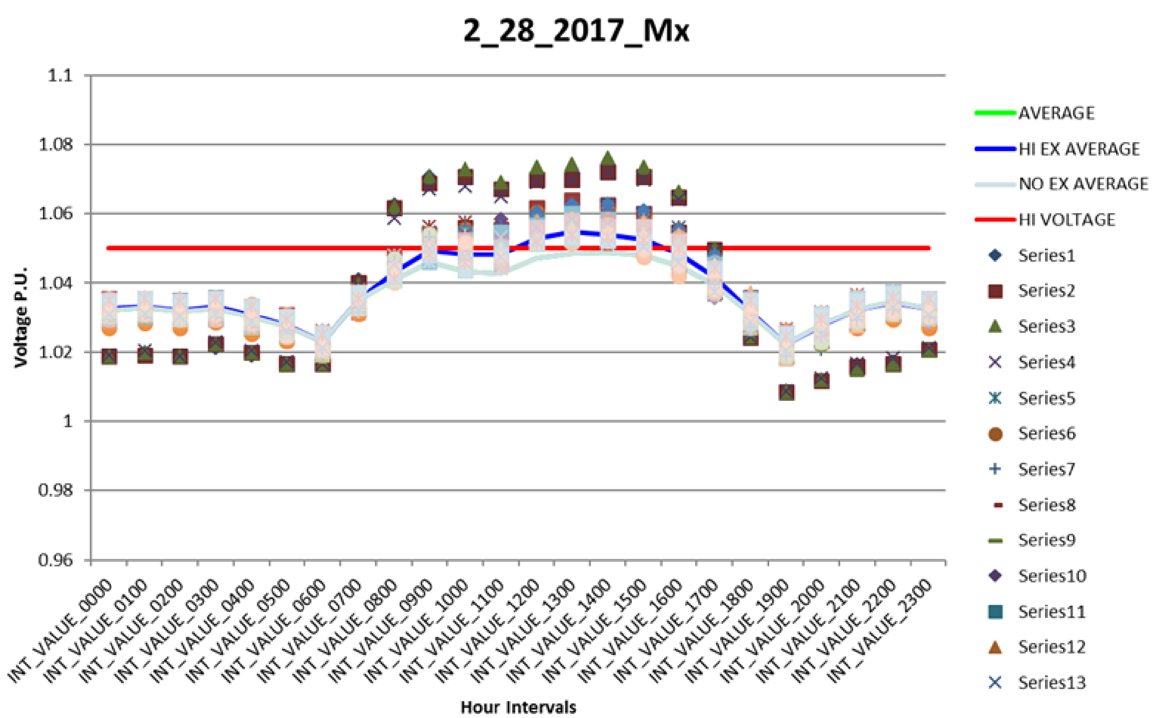

Figure 2-2
Arizona Public Service plot of voltage profiles

Capacitor Health and Control

By adapting a meter socket, the neutral current of a capacitor bank can be monitored using a standard 120-V residential AMI meter. This arrangement can be used on both fixed and switched capacitors. Voltage and kVA data are returned from the meter daily. Based on these data, failed capacitor cans, capacitors with blown fuses, and capacitors with misoperating switches are identified.

Figure 2-3 represents how the AMI meter is connected through a current transformer (CT) to the capacitor. A CT is used to connect to the neutral to keep surges through the neutral from damaging the meter.

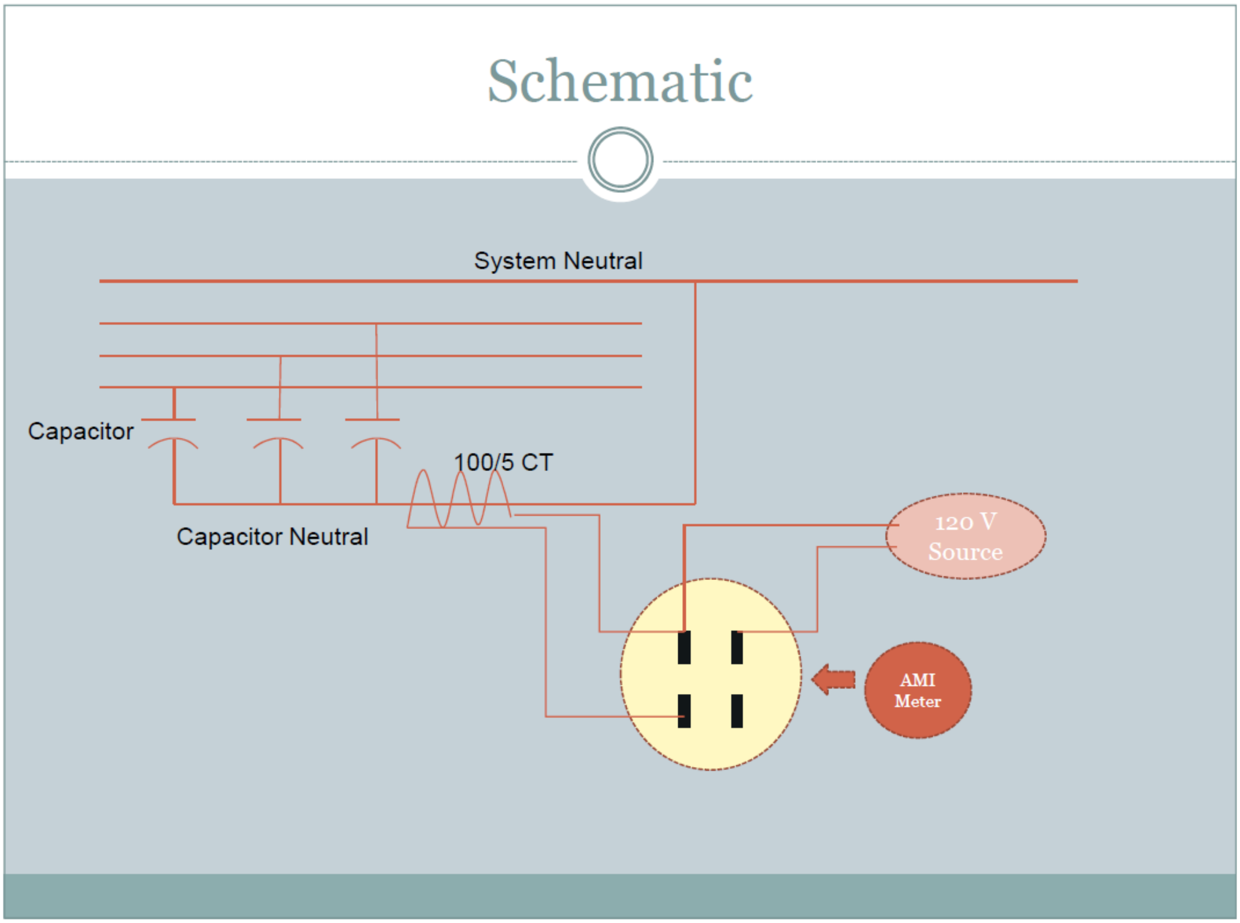

Figure 2-3
AMI capacitor monitor

Following the success of the AMI-based capacitor monitor to identify health issues, a second meter adapter was created that has electronics to monitor and control a switched capacitor based on the status of an AMI meter with connect and disconnect capabilities (see Figure 2-4). The electronics in the adapter monitors the load spade of the AMI meter. If the load spade is energized, after a delay, the electronics send a close pulse to the capacitor switches. If the load spade becomes deenergized, after a delay, the electronics send an open pulse to the capacitor switches. The AMI meter becomes the monitor and the controller and completely replaces the capacitor control. This type of monitor and control are dependent on a centralized volt-var system to control the position of the AMI meter, which, in turn, controls the position of the capacitor switches. A more detailed article about this process can be found in the February 2013 issue of *T&D World* magazine.

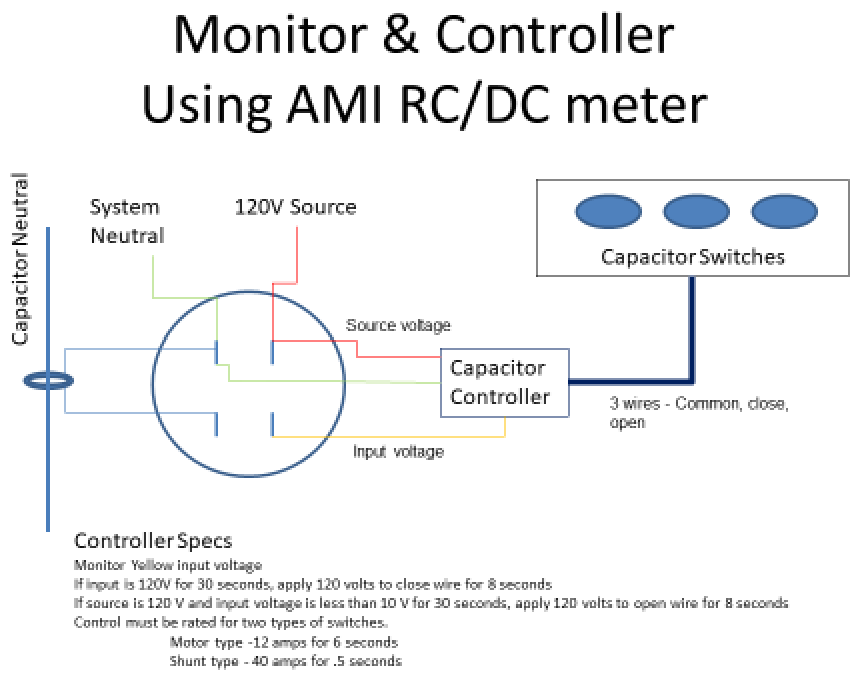

Figure 2-4
AMI capacitor monitor with control module

Identify Mapping Errors

Customers are increasingly interested in more information associated with their service, especially proactive communication from the utility with information about their outages. The relationships between the customer's meter, the service transformer, the phase to which the transformer is connected, and the protective devices are critical in allowing utilities to provide accurate information. AMI offers several opportunities to identify mapping errors.

Using Outages

For single-phase faults and transformer faults, mislinked AMI outage notifications create predicted outages on uninvolved transformers or phases. The outages are identified by the system operators. Many OMSs allow the system operator to move the AMI meter to a different transformer. This move is then incorporated into the database that links the meter to the new transformer for all future events. When multiple meters are mislinked, utilities have created processes for the operator to request a map change. Because every mislinkage meter creates an outage event that the operators must manage, it is in the operator's interest to correct the map whenever practical.

Using Momentary Outages

Following a successful single-phase reclosing event, AMI momentary data can be compared to AMI phase linkage to identify mismatches. In addition to the reliability benefits of single-phase reclosing, feeder breakers that have single-phase reclosing can be used to correct meter linking on the entire feeder. Every single-phase fault can be used to update the map.

Using Voltage Data

Feeders with single-phase regulation have had their voltage data analyzed to determine if sufficient grouping can be done to identify phases. EPRI published a report in 2018 [1] with the following key findings:

- Correlation and regression models performed reasonably well for the six feeders evaluated using only voltage measurements.
- A method to reduce the amount of data needed for phase identification was to intentionally create a change in voltage on one phase. With individually regulated phases, this was easy, quick, and almost foolproof.
- Prediction accuracy rates were higher in cases when both the voltage and consumption data were included in the regression analysis.

Overutilized and Underutilized Transformers

Many utilities have used AMI usage and demand data to identify overutilized or underutilized transformers. Obviously, the larger the transformer, the more value there is in keeping it from failing from overload or replacing it with a smaller transformer. The process is very straightforward for transformers with only one customer served from the transformer. Each utility has its own criteria for what percentage above or below nameplate they are willing to accept. The same process can be applied to smaller transformers by summing the AMI meters that are linked. This process will identify overloaded transformers and can identify transformers that have many mislinked meters.

Past 24-Hour Transformer Loading for Replacements

Extreme weather events associated with extreme heat or cold can create many transformer outages. Having the past 24-hour loading data for transformers enables operations to make an informed decision as to whether a transformer should be replaced or simply refused. Because refusing a transformer is many times quicker than changing the transformer out for a larger size, having loading information readily available can dramatically impact the restoration time.

Individual Solar Distributed Energy Resources Identification

By looking for changes in voltage, interval load, and power factor, a standard residential AMI meter can identify the presence of solar photovoltaics so that the utility can properly model and plan the distribution system. The addition of radiance and/or wind data can further enhance identification and establish baseload projections that can be used to approximate the generation size. The data points required and the specific algorithms are being determined. If successful, customers with rooftop solar who did not register their installation with the utility can be identified.

Individual Electric Vehicle Charging Identification

By looking for changes in voltage, load, and power factor, a standard residential AMI meter might be able to identify the presence of an electric vehicle (EV) charging system so that the utility can properly model and plan the distribution system. The data points required and the specific algorithms are being determined. If successful, customers with EV chargers who did not register their installation with the utility can be identified, planned for, and educated about any rates that would encourage off-peak charging.

Feeder Solar Distributed Energy Resources Identification

By plotting average voltage on a feeder, feeders with high voltage away from the substations are being used to identify the feeders that have enough solar penetration to impact the voltage profile. This can also be accomplished by comparing average voltage readings between meters close to the substation (V1) with those further down the line (V2). Circuits are flagged when the differential (V1-V2) exceeds a preset negative number.

Customer Heating Method Identification

After a high number of transformer failures during a period of abnormally cold weather, a Dominion Energy investigation proved that many of the failures could be contributed to customers changing their home heating source from gas to electric. If Dominion could use AMI to determine the heat source for each customer, the transformers serving those customers could be identified and resized before failures occur. Dominion began an AMI analytics effort to identify the heating method of each customer.

In 2017, Dominion installed a data repository designed to capture and store the vast amount of data that AMI can generate. Using the interval data from their residential meters, Dominion was able to successfully group customers by their heating method by grouping customers based on their sensitivity to temperature. Although AMI provided 30-minute usage resolution, Dominion is performing the same analytics on monthly data to determine if the resolution provided by AMI is critical for successful heating determination.

Reliability Indices Audits

Many utilities have kept the calculation of reliability indices within the OMS and used the time stamps within AMI meters as a tool for validating or correcting outage records to increase accuracy.

Single-Phase Outages Modeled As Three-Phase

AMI reported outages can be analyzed to highlight reclosers that were modeled as all three phases open when only one or two phases were involved in the outage event. Changing a three-phase recloser outage to a single-phase outage can dramatically reduce the number of SAIDI minutes reported. These instances can be found by sorting three-phase outages by the number of AMI reported outages per phase. Outages with one or two phases with low representation should be studied. The process will also help correct mapping errors.

Outage Associations

The outage start times of all the meters associated to an outage should be close to the same time. Having a process to identify outages with meter start times outside of an acceptable band can identify separate outages that have been associated by the OMS. An OMS will use the earliest prediction as the start time of the outage. For example, a transformer outage with four customers occurs at noon and is predicted in the OMS but not confirmed by an operator. At 2:00 PM, the feeder serving the transformer opens, creating an outage for an additional 2000 customers. The feeder outage is restored at 3:00 PM. At 4:00 PM, customers on the transformer call back and are re-predicted out. The transformer is restored at 5:00 PM.

Equation 2-1
Reported versus actual customer minutes of interruption (CMI)

Reported CMI = 2004 x (15-12)hrs + 4 x (17-15)hrs = 361,200 customer minutes
Actual CMI = 2000 x (15-14)hrs + 4 x (17-12)hrs = 121,200 customer minutes

Overloaded Hydraulic Reclosers Identification

Momentary outages can confuse an outage management system. However, they are useful at identifying overloaded hydraulic reclosers. Hydraulic reclosers trip when the current approaches two times the rated current. When the recloser operates, some of the load does not immediately come back. After a short period, though, the load will return and make the recloser trip again. In a high-load weather event, the trip and reclose sequence can happen many times. Following weather events that cause an increase in demand, momentary outages can be plotted on a map (using map coordinates) to identify hydraulic reclosers that are operating due to load. The map plots customers with greater than X momentary outages within the weather period. Pockets of outages that appear on the map behind hydraulic reclosers indicate a recloser that was probably operating due to load. Without AMI, these operations might go unnoticed until the recloser fails or customers complain.

Nested Outage Predictions

A nested outage is a small outage associated with a much larger outage. A good example is a blown fuse on a feeder that is deenergized for a different fault event. After the feeder is restored, the customers behind the fuse will remain out. Unless the outage is associated with a major weather event, first responders might not assume that there are multiple fault events. After clearing the fault on the recloser or breaker, the first responder might leave the area unaware of the fault behind the fuse. The outage must be identified later and because the AMI meters will have already used all of their stored energy, the nested outage is dependent on customer calls to re-predict. If the customers behind the fuse have already called, they might not realize that they need to call again, until their frustration increases. The customer’s initial call will be associated with the larger outage by the OMS and completed. Sending power on messages will prompt customers to call sooner. But notifying a customer that their power is on when it is still off can also create a negative customer experience.

OMS Association Rules

AMI has the potential to identify nested outages. As AMI outage reporting continues to get faster and more accurate, OMS prediction rules can be adjusted to take advantage of the speed and quantity of outage reporting. One such OMS rule is the time in which outages are locked and prevented from being associated with a larger outage. For example, if the time to lock the outage is set at 5 minutes, a fuse outage that occurs at least 5 minutes prior to an upstream recloser lockout would be locked in as a nested outage. Events that are locked will be identified to system operations as a separate event from the larger event. Locking the event as a nested outage also keeps customers associated with the nested outage from getting a power restore message when the larger outage is restored. Care should be taken when reducing the time waited before an outage is locked. If the time is set below what the AMI outage reporting can support, a large single event might be predicted as many smaller events.

In severe weather events, utilities expect multiple cases of trouble and require field crews to inspect the entire line before energizing. These inspections include the reporting and modeling of open protective devices before closing source devices to restore service. By modeling the nested outages, utilities prevent customers from getting erroneous restore messages.

SCADA Alternative

Before pad-mount transformers were available, some large customers would be served from a small substation connected to the distribution system. For example, a large plant might have a 12/4-kV ground-type substation served from the 12-kV distribution system. This type of installation might require the call-out of a first responder with a different skill set than those responding to a standard distribution customer. The same type of customer might have difficulty reporting an outage through the normal outage process. To monitor the service, standard substation SCADA could be installed. However, adding SCADA to old substation-based equipment that usually has electromechanical relays can become very expensive.

As an alternative to installing SCADA, utilities have turned to monitoring the C&I three-phase meter located at these facilities to identify outages. The process might not be able to use the same processes as other AMI meters due to the different construction of C&I meters. As indicated in Table 2-1, meters A3 and C3 do not have indication for either outages or low voltage. Meters without either indication must have the data collected from normal polling analyzed by a back-office application to identify low voltage and create an outage event. Some C&I meters stop communicating any data when the power is lost (they do not have an internal stored energy source). For meters that stop communicating, utilities have put in place back-office systems that will convert multiple failed communication attempts into an outage. If the communication is known to have numerous failures, the system might have to wait several minutes before converting failed communication attempts into an outage message. Meters B3, D3, and E3 all report outages and low voltage, but, typically, only one phase will be monitored for outages. If the substation can experience single-phase outages, an alternative process must be developed. The processes to monitor these installations can be repurposed to monitor all C&I meters.

3

USE CASES THAT REQUIRE ADDITIONAL DEVELOPMENT

Identifying Nested Outages with Reverse OMS Predictions

OMSs and AMI restoration messages can also be used to identify nested outages. The OMS uses the AMI restore message to “predict restorations.” OMSs have the topology required to predict nested outages based on the absence of restore messages sent from the AMI meters. Following a restore event (closing a protective device in the model), protective devices that are not already confirmed open are predicted open using restore prediction rules similar to outage prediction rules (protective devices without X number of restore messages within a defined period) to identify nested outages. To further enhance the accuracy of the prediction, the system can ping a subset of the meters behind a protective device that does not have any restore messages before creating a nested outage. In a large event, this system would be very helpful at identifying transformer outages that were missed by the line inspection. For mesh systems, a time delay to allow the network to reestablish itself will be required.

Step Restoration with Reconnect/Disconnect Meters

If meters with a built-in disconnect have a stored energy source that can open the disconnect without ac present, the disconnect switch can be used to mitigate temporary overloads that might occur during restoration activities. The temporary overload condition might be a result of cold load, or it might be the result of distributed energy resources (DER) disconnecting during the disturbance. The logic to disconnect could include a temperature variable so that the disconnect occurs only during high or low temperatures. This function would extend an outage, but the extension would be minimal and occur only during high-load periods. A wait time of 2 minutes would be sufficient. If all the residential meters have disconnect ability, the reconnect wait time can be a random number within a range to keep all the meters from reconnecting at the same time.

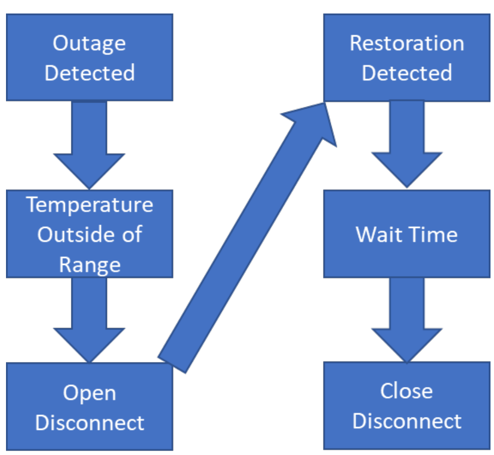

Figure 3-1
Step restoration using internal meter disconnect

Under-Frequency Load Shed with Reconnect/Disconnect Meters

Meters that have a built-in disconnect switch can be used to mitigate generation disturbances by opening for under-frequency. The under-frequency pickup of the meter is set to have the meter open before the substation-based under-frequency relays open the feeder breaker. By using AMI meters as the disconnect, the circuit can remain in service to serve critical loads and important services, such as traffic lights, gas stations, and some businesses. Upon disconnecting for under-frequency, the meters must receive a close command from the AMI system before reconnecting the load. Having AMI-based under-frequency does not mean that substation-based under-frequency is eliminated. AMI under-frequency can be designed to operate first, faster than substation-based relays. But by keeping substation-based under-frequency in place, the substation relays are the only devices that would be periodically tested to meet reliability requirements. The system developed to close the meters once the generation stabilizes would need to include a feedback loop to identify meters that did not respond to the close command and block the close of meters that were disconnected for auxiliary reasons.

Targeted Load Shed with Reconnect/Disconnect Meters

Meters that have a built-in disconnect switch can be used to mitigate generation shortfalls by opening from a command originating in a load shed application. The load shed application could either select the number of meters based on the desired kW reduction or select meters by feeder. By using AMI meters as the disconnect, the circuit can remain in service to serve critical loads and important services, such as traffic lights, gas stations, and businesses. Upon activation, the meters must receive a close command from the AMI system before restoring load. Because load shed events often result in a rolling blackout, the meters selected must be organized in a manner that facilitates reconnection. If there were not enough self-contained meter load to allow a second block of disconnects, the utility could decide to leave the initial group out for an extended period or move to feeder-level disconnection. Ideally, the decision to establish the AMI-based load shed approach would include the mass deployment of capable meters.

Neutral Problems

In general, single-phase self-contained meters do not have a neutral reference. This limits the meter's ability to identify voltage swings between the phase conductors and the neutral and in turn limits its ability to identify neutral problems. However, three-phase meters do have a neutral connection and have proven very effective at identifying phase-to-neutral voltage swings that identify corroded or loose neutral connections. Utilities have successfully written applications that look for loose neutral conditions associated with C&I meters.

CT Issues (Three-Phase Meters)

The data from three-phase meters can be analyzed to identify CT problems as well as any wiring errors associated with potential or current transformers. Because these errors are normally associated with large customers, not identifying these issues can cause large loss of revenue due to inaccurate metering. Utilities have established unmonitored processes to identify data abnormalities that indicate onsite construction or materials issues.

4
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