# Integrating AMI with Distribution Operations

*Use Cases That Benefit Distribution Operations*

**3002013423**

# Integrating AMI with Distribution Operations

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Technical Update, December 2018

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# ABSTRACT

Utilities have installed advanced metering infrastructures (AMI) for many years. From the early power line carrier systems to today's wireless options, all have effectively reported electricity usage. But, for many companies, the benefits of AMI to departments other than meter reading have been slow to materialize. There are many documented use cases for AMI that take advantage of the consumption meter's ability to act as an end-of-the-line sensor and controller. Available communication technologies that allow utilities to collect consumption data from AMI include drive-by radio systems, power line carrier systems, mesh radio systems and tower-based systems. Adding a temporary backup power source enhances a meter's ability to act as a sensor. This report contains a list of potential use cases for AMI that benefit operations based on data gathered at several utility workshops.

Many of the use cases are associated with reporting outages and can be grouped into three categories based on the kind of communication after AC power is removed. The three categories are meters with stored energy for a few seconds of operation; meters with stored energy for an extended period with a mesh backhaul system; and meters with stored energy for an extended period with a tower-based backhaul system. Many techniques are available to help utilities ensure that meters can accurately determine whether an outage is temporary or sustained. Because incorrectly reporting a temporary outage as a sustained outage creates nuisance busywork for distribution system operators (DSO), AMI systems that cannot accurately distinguish between temporary and sustained outages are often blocked from reporting outages. As a result, the potential benefits of AMI outage reporting are eliminated.

**Keywords**
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## Product Title: Integrating AMI with Distribution Operations: Use Cases That Benefit Distribution Operations

**PRIMARY AUDIENCE:** Advanced Meter Infrastructure Managers, Managers of Distribution Control Centers, Managers of Distribution Management Systems.

**SECONDARY AUDIENCE:** Distribution Operation Engineers, Distribution System Operators.

### KEY RESEARCH QUESTION

Utilities have been deploying advanced metering infrastructure (AMI) systems with many different technologies mostly driven by the immediate need to accurately collect data associated with electricity usage. With each utility's infrastructure and topology being unique, there are many different deployment strategies. This research aims to explore the factors which enables a utility to realize operational benefits associated with AMI deployments as well as document the challenges that each approach has meeting all the utility's desires.

### RESEARCH OVERVIEW

This research continues the research aimed at maximizing the investment in AMI equipment and communication systems for providing benefits to operations. This research also identifies best practices associated with distinguishing between temporary and sustained outages for the different types of AMI systems deployed.

### KEY FINDINGS

- Distinguishing between temporary and permeant outages is required for integration into the OMS system.
- The amount of time the meter can function without power determines if the meter can process outages locally.
- The voltage threshold for an outage varies by meter manufacture. This variance affects a few of the use cases

### WHY THIS MATTERS

This research has identified many beneficial use cases for AMI to support operational goals. The research provides examples of ways that utilities have modified their original AMI deployments to maximize the contribution to Operations.

## HOW TO APPLY RESULTS

This research can be the basis for a discussion between Operations and Metering before an AMI purchase occurs. This research can also help identify benefits that can be realized with current AMI deployments.

## LEARNING AND ENGAGEMENT OPPORTUNITIES

- Interested individuals might also consider attending a Distribution Operations Interest Group (DOIG). The DOIG brings together control center managers to discuss issues related to Distribution operations.
- Finding Live Down Conductors supplemental, provides individual utility support to deploy an AMI based system to identify live down conductors.

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**PROGRAM:** Distribution Operations and Planning P200, Distribution Operations P200C



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# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| AMI | advanced metering infrastructure |
| C&I | commercial and industria |
| CMI | customer minutes of interruption |
| CT | current transformer |
| DER | distributed energy resource |
| DMS | distribution management system |
| DOIG | Distribution Operations Interest Group |
| DSCADA | distribution supervisory control and data acquisition |
| DSO | distribution system operators |
| EPRI | Electric Power Research Institute |
| EV | electric vehicle |
| FLISR | fault location, isolation, and service restoration |
| HIAMI | Hazard Identification using AMI |
| OMS | outage management systems |
| SAIDI | system average interruption duration index |
| SCADA | supervisory control and data acquisition |
| VRU | voice response unit |

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# 1
# UTILIZING AMI OUTAGE MESSAGES

## Description

Customers frequently expect their utilities not only to be aware of outages but also to communicate outage information without any action by the customer. Utilities without advanced metering infrastructure (AMI) outage reporting capabilities can only meet this expectation for outages that occur behind equipment monitored with supervisory control and data acquisition (SCADA) systems. Without AMI meters that automatically send outage messages to the utility, outages behind devices such as hydraulic reclosers and fuses depend upon customers to notify the utility about the outage. An AMI system can report outages quickly and reduce the amount of time needed to identify the open protective device. By eliminating the need for customers to report outages, AMI systems can allow utilities to change the way that they process outage information and communicate with affected customers.

## Momentary Versus Sustained Outages

Momentary outages occur when a system's protection and restoration schemes work as designed to re-energize the system following a temporary fault or to isolate permanent faults to affect the smallest number of customers. The length of a momentary outage depends upon the reclose times programmed into protective devices and the time required for automation systems to restore customers from alternate sources. By contrast, a sustained outage is one in which customers lose power until the utility can restore service.

Knowledge about momentary outages is beneficial, and momentary outage data is employed in many use cases. Because none of the use cases associated with momentary outages require immediate response from the distribution system operator (DSO) or a first responder, collecting momentary outage data can occur as part of normal meter reading schedules. Sustained outages require the DSO's immediate attention to manage power restoration. If AMI, outage management systems (OMS), and SCADA systems can work together to identify sustained outages, restoration processes and customer communications about outages can be greatly improved.

## Outage Identification

In general, an AMI meter can be separated into two distinct modules: the metrology module and the communication module. Communications modules rely on established interoperability standards that allow a utility to choose a communication system that best suits their needs and deploy the associated communication module in any meter that supports the standard regardless of manufacturer. The AMI communication module support several important outage-reporting functions. Data processing in the module determines whether an outage is temporary or sustained, and stored energy in the communication module allows it to continue operation after the power supply from the meter is disconnected. The communication module also contains a clock to execute timing functions.

If a meter manufacturer integrates the communication and metrology modules into a single unit, the utility must rely on the communications method implemented by the manufacturer. However, despite the departure from the standard, integrating communications and metrology can provide some additional functionality. Meters that deviate from the standard are often built by companies whose products include both meters and AMI communication technology. Some polyphase meters also perform outage functions in the metrology portion of the meter.

The process to determine whether an outage occurred is the same for most communication technologies, with just a few variables. The first variable is the **outage threshold voltage** (Table 1-1) in the metrology portion of the meter, which represents the dip in voltage that causes a drop in power to the communication module. The outage threshold voltage is usually expressed as a percentage of nominal voltage, and varies depending on the meter manufacturer. The second variable is the **sustained outage timer**, which is the amount of time that the communication module experiences a loss of power from the meter before it transmits an outage event message.

**Table 1-1**
**Outage threshold table for Georgia Power's deployed meters**

| 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 |

*All meters programmed with a six cycle (minimum) delay when voltage drops to above levels
*Nominal voltages selected based on meters primary use on our system

Because the outage threshold is a function of the power supply in the metrology portion of the meter, it is not a variable that can be changed. By contrast, the sustained outage timer is calculated by the communication module software, and many systems allow the timer to configured within the communication module's stored-energy limits.

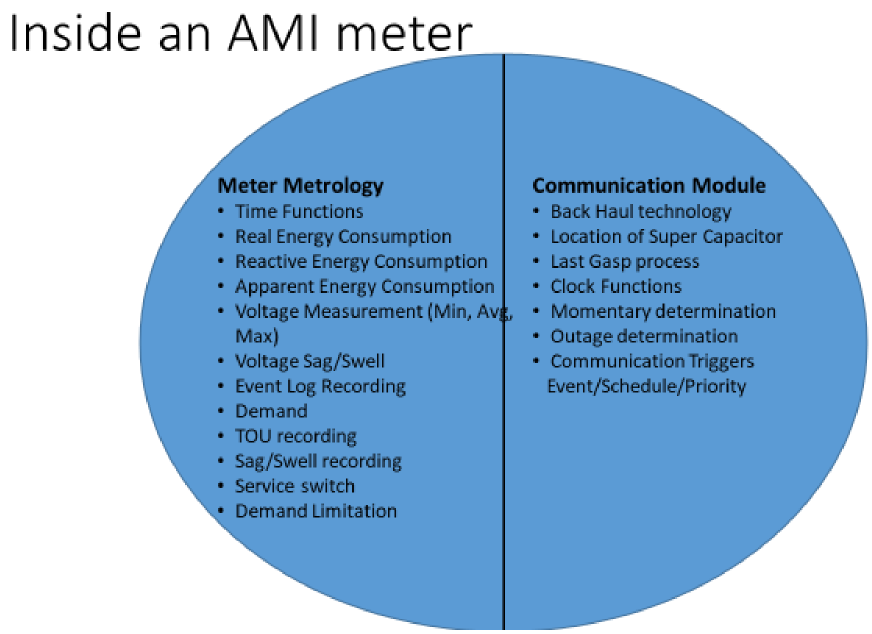


**Figure 1-1**
**Metrology and communication modules in an AMI meter**

For early models of AMI, stored energy could power the communication module for only a few seconds. Modern AMI meters rely on an internal capacitor that can maintain the communication module's operation for several minutes. If the stored energy is limited, the sustained outage timer is set to zero. If only a few minutes of stored energy are available, the sustained outage timer can be set anywhere from a few seconds up to 100 seconds. For AMI systems with many minutes of stored energy, the sustained outage timer can vary between a few seconds and several minutes.

### *Determining Sustained Outage Timer*

Because meter reset voltage is not maintained during reclose attempts, reclose times must be added together to establish the total time to lockout. For example, a feeder breaker with a 3-second, 15-second and 30-second reclose times could have a successful restoration 48 seconds after the start of the event. To be conservative, the sustained outage threshold would be set at greater than 48 seconds so that the AMI only identifies outages lasting longer than 48 seconds as sustained outages. Setting the wait time too low will result in some momentary outages being reported as sustained outages, while setting the sustained outage threshold too high can result in customers reporting their outage to the utility faster than the AMI system. In addition, setting the sustained outage timer too long will reduce the amount of time during which the AMI can send data packets. During large outages, the reduced transmission time may result in fewer outage events reaching the OMS. If reclose times are consistently applied throughout a 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 the AMI system reports a momentary outage as a sustained outage, the DSO will process the outage as sustained. The effort required to process a momentary outage that is incorrectly reported as a sustained outage has prompted some utilities to stop all AMI outage reporting.

Typically, AMI systems that do not accurately distinguish between momentary and sustained outages are not fed into the OMS system, or a process is in place to stop all outages from reaching the OMS system when operations cannot manage the workload associated with the false outage events. In such a case, no AMI outage data is considered better than erroneous AMI outage data.

Some AMI systems are shipped with a default sustained outage threshold of 30 seconds, which is long enough to accurately identify many momentary outages but may be shorter than the time to lockout. If a third reclose attempt is successful and the total time to lockout is greater than 30 seconds, outage messages will be created for customers who were restored with a successful third reclose.

Figure 1-2 provides a graph of successful late reclose attempts versus windspeed, taken from EPRI report 3002011006, highlights that the success of a third reclose rises as wind speed increases. Although this data represents only one utility's experience, the increase in successful third reclose attempts illustrates why utilities with a 30-second sustained outage threshold disconnect the AMI system from the OMS during storms. At some point, increased wind speed will result in major damage and greatly reduce the probability of a successful reclose. While a fifth wind speed measurement is not included in the graph, the possibility of successful reclose at higher speeds is greatly reduced because most if not all operations would result in a lockout.

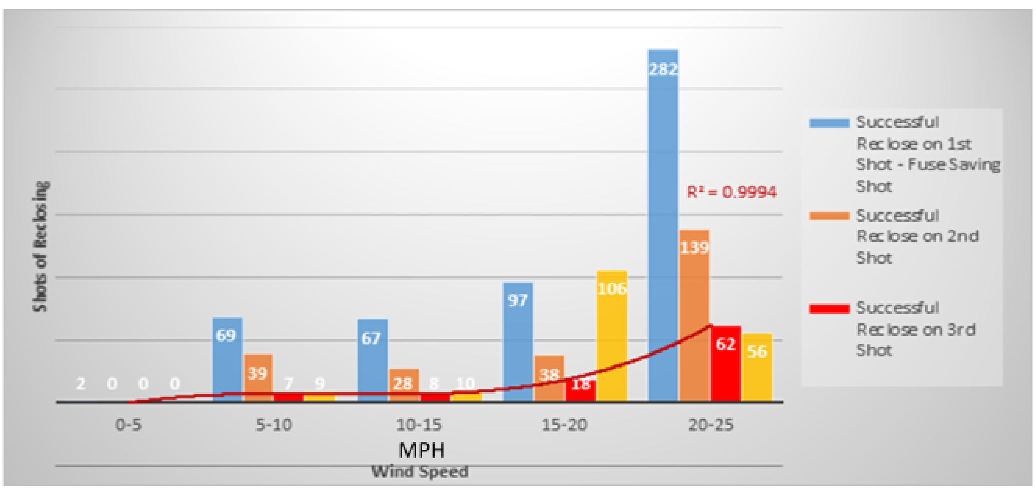


**Figure 1-2**
**Successful late reclose attempts versus windspeed**

### *Outage Flow for AMI Meters with Limited Capabilities After Power Loss*

AMI meters that cannot function beyond reclose times are not able to determine whether an outage is temporary or sustained. Utilities and AMI vendors rely on filtering and association processes to identify which outage messages should be passed as sustained outages; however, these processes tend to add time to the outage reporting process. Since no single process is completely effective, multiple processes are used. As a practice, when processes cannot effectively distinguish between a temporary and a sustained outage, outage messages will be completely filtered out and the utility will depend upon customer calls and/or distribution SCADA (DSCADA) to identify outages.

### Outage Threshold Voltage Event

When a meter initiates an outage trigger to the communication module, the module disconnects from the power supply and begins to operate using its internal power source (usually a supercapacitor). The communication module initiates a low-power mode and saves critical information in nonvolatile memory. Since the amount of stored energy in the communication module is limited, the sustained outage timer is set at 0 seconds. Thus, as soon as the outage threshold voltage is met, the communication module sends an outage event. If the voltage recovers and maintains a level above the threshold before the internal supercapacitor is depleted, the meter will transmit a power restore message.

### Power Restore Messages

If voltage recovers and maintains a level above the outage threshold after the internal capacitor is depleted, the meter must first connect to the mesh backhaul system before transmitting a restore message. If multiple meters are involved in the outage event, reestablishing the network can take up to ten minutes (the exact amount of time can vary based on the manufacturer of the meter).

### Discarding Messages

Because many transmitted outage messages will be associated with a temporary fault or a fault cleared by another protective device, AMI systems try to cancel outage events that can be identified as temporary. The following processes are used to cancel outage messages before the message reaches the OMS outage prediction algorithm.

#### *Matching Outage Events with Restoration Events*

If an outage message can be linked to a restore message, the outage message can be discarded. AMI vendors provide processes in their collection systems to match outage and restore messages from the same meter. These processes must include a time delay to allow the meters to reestablish the mesh network and transmit the power restore message. Some filter systems hold outage messages for up to 15 minutes before attempting to match an outage event to a restoration event.

#### *Discarding Old Outages Affected by Buffering*

The outage creation time is embedded in the outage message from the meter. To prevent buffered outage messages from reaching the OMS, filters discard any outage greater than X minutes old, where X is the age of the outage (defined as the current time minus the outage creation time embedded in the outage message). The value of X must be greater than the wait time for linking to restore messages. If the system can buffer outages, failure to discard old outages can result in some restored outages being classified as still out.

### *Matching Outage Events to SCADA Events*

Tables that relate meters to SCADA devices ensure that if a successful SCADA close operation occurred within a specified time band of the outage time, the outage is discarded. This filter will remove all outages associated with the SCADA device operation.

If a utility relies on "fuse saving" protection philosophy, a permanent fault behind a protective fuse will result in a successful reclose a SCADA-controlled recloser, because the fuse would isolate the fault when the reclosing device begins to operate on delayed curves. Even though all the customers behind the fuse would experience a sustained outage, their outage messages would be filtered out and not passed to the OMS.

If a utility relies on a "trip saving" protection philosophy, a permanent fault behind a protective line or transformer fuse would be isolated by the fuse before the operation of a reclosing protective device. If a utility constantly operates in a trip-saving mode, the SCADA filter could be placed early in the outage filtering process.

Operating in trip-saving mode and filtering SCADA outages can allow a utility to look for restoration messages even if installed meters have limited ability to remove delays.

### *Matching to OMS Close Events*

This filter operates in the same way as the SCADA event filter, except the information about upstream protective devices is generated by the OMS instead of the SCADA system. Outages which are already delayed are filtered out if they are associated with a power restore event in the OMS. Since the OMS already has connectivity tables, this process can be easier to implement than manually creating SCADA relationship tables. If SCADA sends status data to the OMS, the OMS will already reflect all SCADA restorations.

### *Scripted Pinging*

Pinging is the process by which an AMI system interrogates a meter. Meters that respond to the interrogation are known to be energized. Some utilities script a ping attempt to reduce the potential of false outages clearing all the other filters. Meters that respond to the ping attempt are discarded, and meters that do not respond may be pinged multiple times before the outage is allowed to pass to the OMS.

### *Relationship Pinging*

Similar to the SCADA tables, a successful ping in relationship pinging indicates that all meters associated with the same protective device are energized, and all of the related outages are discarded. Relationship pinging may be limited to clearing high-level predictions such as feeder breakers or reclosers. Limiting relationship pinging to high-level outages reduces the probability of mapping errors incorrectly associating customers.

### *Enabler Switch*

Utilities typically install a software block for periods of high activity. For utilities that rely on their AMI communication network for SCADA control, blocking the entire outage process can help remove some of the data congestion associated with pinging. However, the system may still be congested as a result of the number of outage messages sent or when portions of the communication network are lost.

### *Outage Flow for AMI meters with Extended Capability—Mesh Communication Systems*

In mesh AMI systems, the meter is part of the communication backhaul, and the supercapacitors must keep the wireless network functional to collect and transmit packets from nearby meters. Most modern AMI meters include an option that allows a supercapacitor to stay functional beyond normal reclose times (generally up to 120 seconds). These meters can accurately distinguish between a temporary outage a sustained outage at the meter, and only send outage events for sustained outages. Because erroneous outages are not sent, these systems can be integrated into the OMS without the delays associated with the filters used in earlier systems. Although not all filters are removed, in most cases the remaining filters can be performed within a few seconds.

#### Outage Threshold Detected

When the meter initiates an outage trigger to the communication card, the communication card disconnects from the power supply and begins operating on its internal power source (usually a supercapacitor). The communication module initiates a low-power mode, saves critical information in nonvolatile memory, and begins a timer to determine whether the outage is temporary or sustained. If the voltage recovers and maintains a level above the outage threshold, the outage is written into memory as a temporary outage, the timer is reset, and normal operations resume.

Figure 1-3 illustrates detection of a temporary outage and voltage recovery before the time threshold. If the voltage does not recover above X% of nominal and maintain the voltage for at least 2 seconds before the sustained outage threshold timer expires, the event is considered a sustained outage.

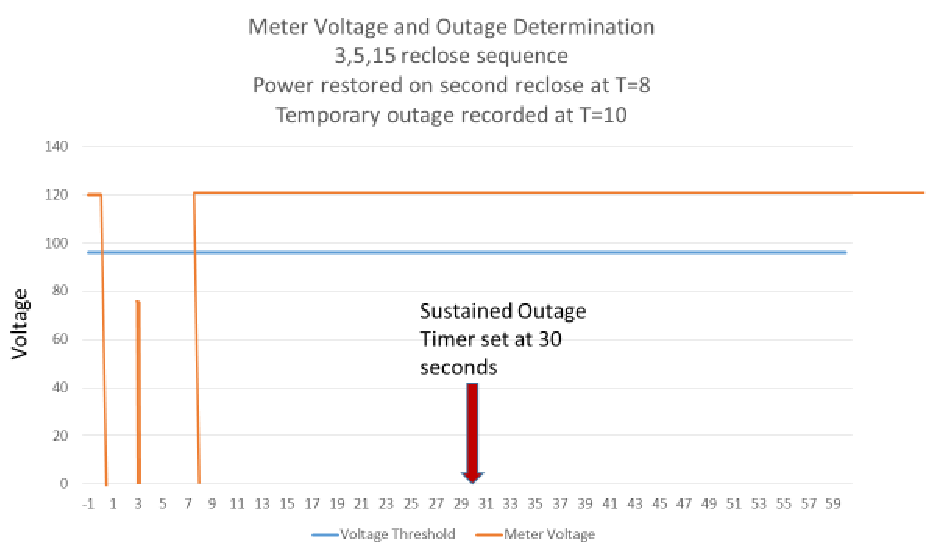


**Figure 1-3**
**Temporary outage detected; voltage recovers before time threshold**

Figures 1-4 and 1-5 both represent events that will create a sustained outage report. In these illustrations, the outage timer is set at 30 seconds. Because mesh-type AMI communication modules are part of the backhaul network and must remain actively receiving and transmitting packets, the module's capacitor is limited in operation time. The outage threshold timer is variable, and extending the time reduces the number of messages that can move through the mesh system. Generally, the outage timer is set between 30 and 60 seconds, which leaves 60 seconds of packet transmission.

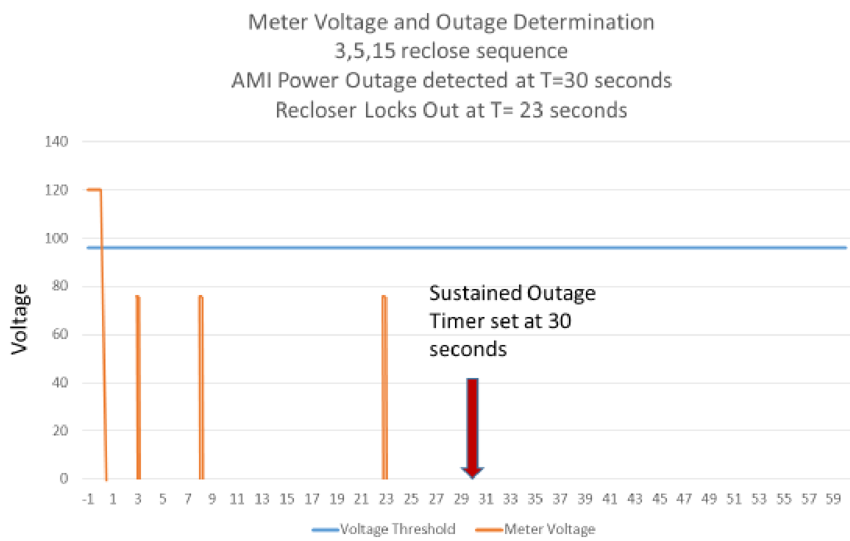


**Figure 1-4**
**Sustained outage detected; voltage does not recover**

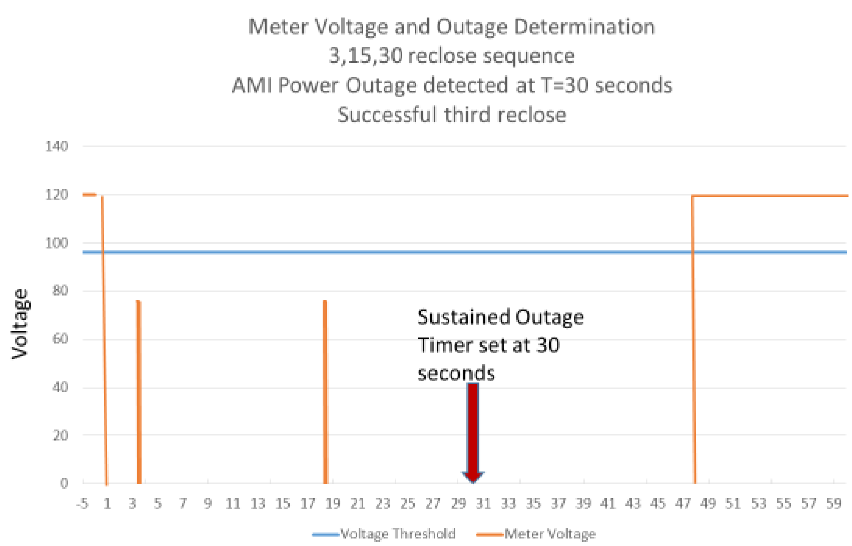


**Figure 1-5**
**Temporary outage identified as sustained; voltage recovers after time threshold**

### Hibernation Mode

After critical information has been saved, the device will enter a hibernation mode that includes disabling radio transmissions. The device will stay in this mode until power is restored or until the sustained outage timer threshold is reached.

### Temporary Outage

If power is restored before the device reaches the sustained outage threshold, the outage is temporary. A radio-detected temporary outage event is recorded, and the temporary counter is incremented. Normal operation resumes immediately.

### Sustained Outage

If the outage exceeds the sustained outage timer, then the device turns on its radio and schedules an outage packet to be sent almost immediately (after a brief and random amount of time has passed). The meter begins receiving outage messages from other meters that have also exceeded the sustained outage timer.

### Endpoint Power Outage Message Transmission

Once all critical data is stored, the communication module schedules the transmission of the endpoint power outage message to occur after a random number of seconds (typically around 15). At the scheduled time, this packet will be sent into the mesh network, which will forward it to the destination collector. The communication module sends only one packet to the network. If the selected device does not respond, the communication module will try alternative devices until the packet is successfully transmitted or the module runs out of energy.

## *Outage Flow Chart for AMI Meters with Extended Capabilities—Tower-Based Communication*

In tower-based AMI systems, including cellular systems, the meter attempts to communicate directly with a radio tower. This design allows the supercapacitor to provide power to the modem's radio in short bursts instead of constantly receiving and transmitting packets. The supercapacitors in modern AMI meters with tower-based communication can stay functional well beyond normal reclose times. In these systems, the sustained outage timer can be set up to 120 seconds while still maintaining sufficient reserve power to communicate the outage message. These meters can accurately distinguish between a temporary outage and a sustained outage, and only send outage events for sustained outages.

### Voltage Drop Detected

When the meter initiates an outage trigger to the communication module, the module disconnects from the power supply and begins operating on its internal power source (usually a capacitor.) The module enters a low-power mode, saves critical information in nonvolatile memory, and begins a timer to determine if the outage is temporary or sustained. If the voltage recovers and maintains a level above the threshold, the outage is recorded as a temporary outage, after which the timer is reset and normal operations resume. If the voltage does not recover and maintain voltage before the sustained outage threshold timer expires, the event is considered to be a sustained outage.

Figure 1-6 shows an event that will not create a sustained outage report. In tower-based AMI systems, communication modules are not part of the backhaul network and can wake and transmit instead of continuously transmitting packets and receiving packets. As a result, the capacitor in the communication module can function much longer than 120 seconds, which makes it possible to set the outage threshold time between 5 and 120 seconds and ensure sufficient energy to transmit the outage message.

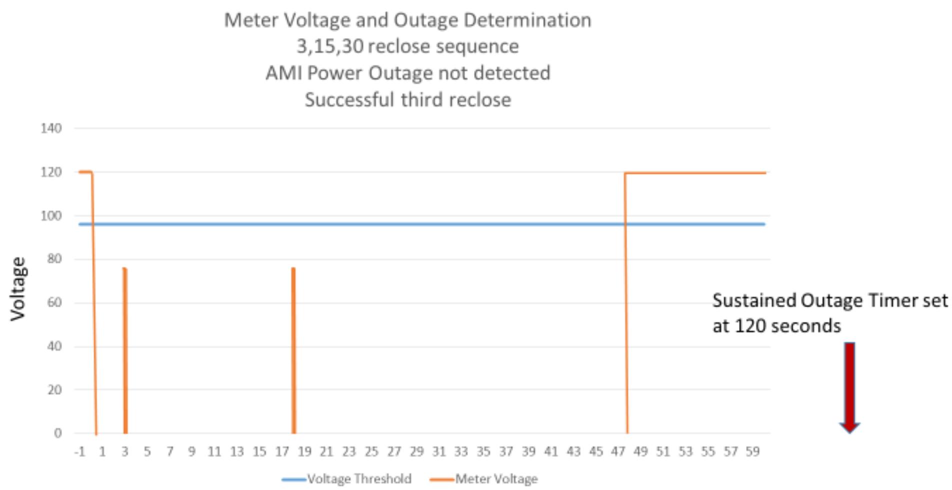


**Figure 1-6**
**Temporary outage detected with successful late reclose**

## Hibernation Mode

After critical information has been saved, the device will enter into a hibernation mode. It will stay in this mode until power is restored or until the sustained outage duration threshold is passed.

## Temporary Outage

If power is restored before the device reaches the sustained outage duration threshold, the outage is temporary. A temporary outage event is recorded. and the counter of temporary events is incremented. Normal operations resume immediately.

## Sustained Outage Message

If the outage is not momentary and lasts longer than the sustained outage timer, the device will schedule an outage packet to be sent. The meter creates its own schedule through a random number generator, and the time before sending the packet can be between 0 and 32 seconds. The random wait time minimizes radio collisions that may occur when all meters experiencing the outage try to communicate with the tower headend. After sending the outage message, a new random schedule is created, and an additional outage message is sent. This process repeats until the stored energy in the capacitor is depleted. If power returns during these repeat attempts, the process is stopped and no additional outage messages are sent.

### Creating Bellwether Meters

For some use cases, such as identifying the location of downed energized conductors, the outage status of a particular meter—known as a bellwether meter—can provide more information than the general population of meters. Some utilities create different rules to increase the probability that a bellwether's outage message is delivered successfully. If a set of bellwether meters is identified, their sustained outage timer can be programmed to respond more quickly to an outage than the general population of meters, which increases the probability that the bellwether meters' outage message will be received. But, if a bellwether meter randomly selects a wait time that is greater than the difference between the bellwether's sustained outage timer and the general population's sustained outage timer, there is still a chance that the bellwether meter's message may occur at the same time as another meter's message. To avoid a potential radio collision, bellwether meters can have their outage timer set to ensure that their outage messages are transmitted before the sustained outage timer for the general meter population is exceeded.

## *Outages Restored by FLISR systems*

Outages that are restored by fault location, isolation, and service restoration (FLISR) systems pose additional challenges for AMI systems. Figure 1-7 illustrates an outage associated with a FLISR restore. In this example, an outage threshold of 60 seconds would report an outage to the OMS while an outage threshold of 120 seconds would accurately report the outage as a temporary outage.

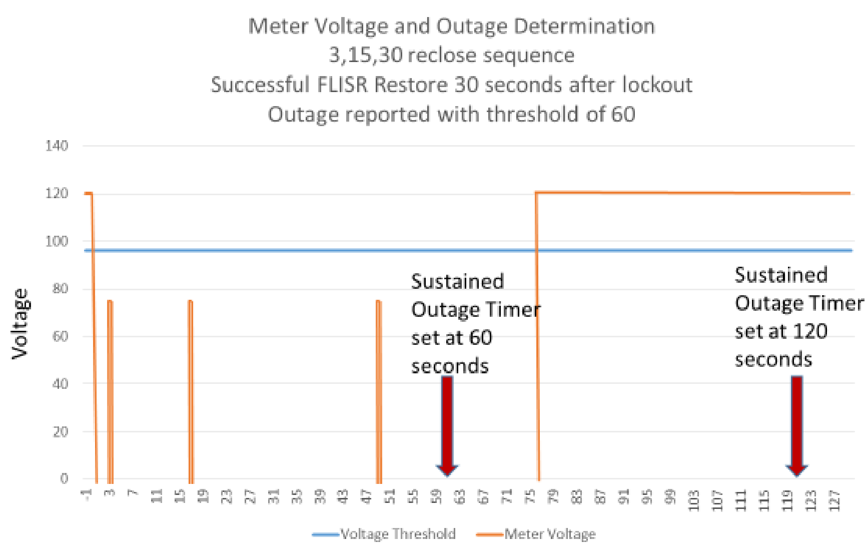


**Figure 1-7**
**Determining outages restored by FLISR systems**

If the OMS has a data connection to SCADA, automated partial restoration activities can be accurately reflected in the OMS. To prevent buffered outage messages from repredicting, OMS systems use a time-delay setting that groups outage messages with restoration activities. In Figure 1-8, outage messages from customers or meters in the restored area will be automatically closed within five minutes of restoration, similar to discarding outage messages associated with a SCADA operation. Selecting a wait time that is too long might result in associating a new customer call from a nested outage with the restore event.

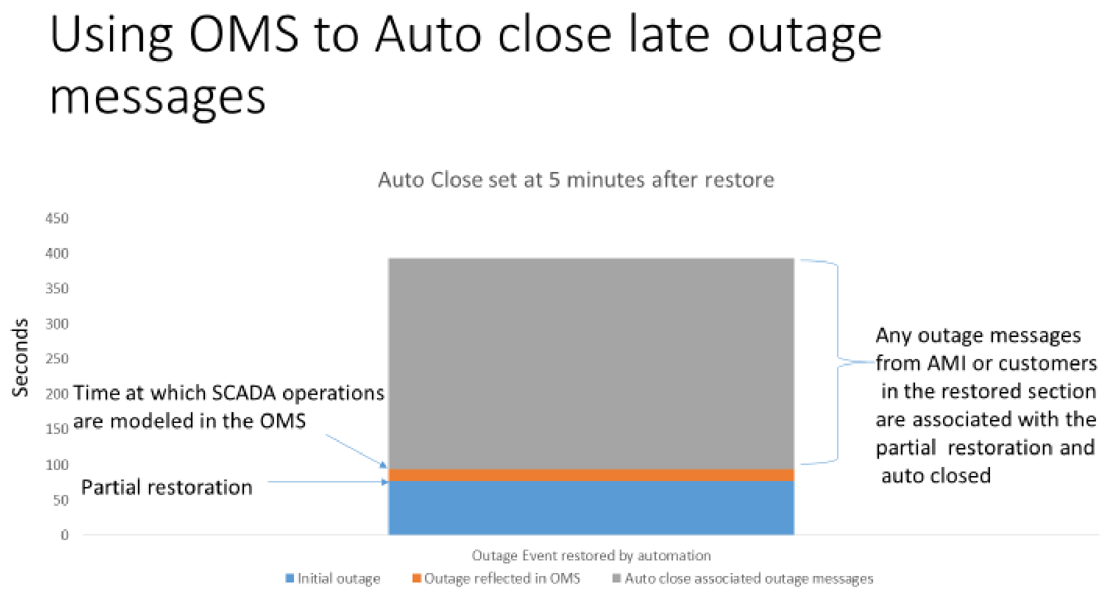


**Figure 1-8**
**Using OMS to close FLISR-restored outages**

### Undesired Outage Message Filters

An effective outage reporting system can filter undesired sustained outages before they are passed to the OMS or filter the messages within the OMS. Common filters are discussed below.

#### *Meters With Active Work Orders for Their Locations*

Blocking the outage message from 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-related work orders. Because work that involves de-energizing a transformer is usually only associated with one of many meters attached to the transformer, a crew must inform operations before de-energizing a transformer that serves multiple customers because only the meter identified in the work order may be filtered out. Active work orders can also be scripted to block outages from all customers connected to the same transformer as the meter that has the work order. Since knowing a crew's work location is beneficial for the DSO, requiring that crews call in before deenergizing a transformer is a good practice. If the DSO's workload allows, the DSO can allow those outages to enter the OMS and then verify that 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 correct the model.

#### *Inactive Meters*

Inactive meters might have a filter that blocks their messages, or the outage in the OMS might be marked as inactive. When responding to single meter outage associated with an inactive meter, the inactive flag allows the operator to inform 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 service conductors. While it is possible to completely filter out events associated with inactive meters, doing so can create a hazardous situation such as tearing energized overhead service from the house of an inactive account.

### *Meters With Active Tamper Alerts*

Some meters report both an outage and a tamper alert when the meter is removed. Outage events associated with tamper events are generally blocked from the outage process, and the tamper message is 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 including some that are cannot correctly distinguish sustained and momentary outages, the utility can choose to only pass outage messages originating from the meters that can distinguish types of outages. Filtering the older meters reduces the need for more complicated filtering.

### *Single-Customer Outages*

Single-customer outages are often filtered out in areas where electricians remove meters to work on customer facilities. While this practice reduces truck rolls to planned customer outages, filtering these outages can keep single-customer outages from being reported. Some utilities apply this filter only during normal business hours so that single-customer outage events pass to the OMS at times when electrician work is not common.

Single-customer outages require different investigation techniques. Many events 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 in which a customer does not call. The business rule may require contacting the customer to make them aware that a crew will be investigating. Another option is to dispatch a responder to inspect the transformer and provide service at street level without entering the customer's premises until contact is established.

## Outages for Customers With Multiple Accounts

Phoned-in outage reports from customers with multiple accounts can be difficult to process because customers may be unable to provide an account number or a meter number. In fact, in some cases, a customer may not even be able to provide the address associated with the account. If the outage is reported by the customer's meter instead of the customer, operations will receive the location and other information needed to respond to the outage.

AMI meters can be valuable in campus designs where data from multiple meters is combined into a single bill. When an AMI meter associated with a transformer reports an outage, the exact location of the outage is known. Because large commercial and industrial (C&I) sites can also benefit from AMI meters, utilities may choose to deploy an AMI meter to provide accurate and timely information when C&I customers deploy meters that use a different communication protocol or that do not report outage events. Three-phase meters are normally powered from just one phase. If single-phasing protection exists, a separate process will be needed to identify outages on a phase that does not provide communication power.

### Nested Outage Predictions

A nested outage is a small outage associated with a much larger outage. Consider 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 consider the possibility of multiple fault events, and after clearing the fault on the recloser or breaker, the responders might leave the area not knowing about the blown fuse. In this case, the nested reason for the outage (the blown fuse) must be separately identified later. If an AMI meter has used all of its stored energy to report the initial outage, it cannot send another outage message and the utility will not be aware of the outage until a still-out customer calls. If a customer behind the blown fuse has already called to report the outage, they may assume that the utility already has all the information it needs when in fact the utility is not aware of the customer's continued outage. In this case, the customer may not call until their frustration increases. Frustration can be compounded if the OMS associates a customer's initial call with the larger outage and sends the still-out customer a message that their power has been restored. A customer who receives an incorrect power-on message may be more likely to call the utility and report their continued outage, but as a general practice, sending power restore messages to customers whose power is off creates a negative customer experience.

#### *OMS Association Rules*

AMI has the potential to identify nested outages. As AMI outage reporting becomes faster and more accurate, OMS prediction rules can be adjusted to take advantage of its speed and quantity. One prediction rule establishes which outages are locked and prevented from being associated with a larger outage. For example, if an outage is set to be locked at five minutes, a fuse outage that occurs at least five minutes before an upstream recloser lockout would be locked in as a nested outage. Events that are locked will be identified to system operations as separate from the larger event. Locking the event as a nested outage also ensures that customers experiencing the nested outage do not receive a power restore message when the larger outage is restored. However, care should be taken when lowering the amount of time before an outage is locked. If the time is set lower than the AMI outage reporting supports, a large single event might be predicted as many smaller events.

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

#### *Reverse OMS Predictions*

OMS systems and AMI restoration messages can also be used to identify nested outages. The OMS system uses the AMI restore message to "predict" restorations. OMS systems can predict nested outages based upon 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 confirmed open are predicted to be open based on restore prediction rules similar to outage prediction rules (protective devices without X number of restore messages within a defined time period) to identify nested outages. To further enhance a prediction's accuracy, the system can ping a subset of meters behind a protective device that has no restore messages before creating a nested outage. During a large event, this kind of system could help identify transformer outages that may have been missed during line inspection. For mesh systems, a time delay to allow the network to reestablish itself will be required.

The utility must determine the timing of customer restoration messages. For example, should the utility immediately notify customers that their outage is complete when the source device is closed, or should the utility wait for the OMS and AMI restoration prediction systems to confirm that the customer is not part of a nested outage (which might take 10 to 20 minutes)? When an AMI restore message is received, the OMS will confirm the connected transformer energized and send a power-on message to all customers connected to the transformer. After a predefined amount of time, the OMS would ping transformers that did not have any AMI restore messages.

### *Visualization of Outages and Restorations*

#### Stand-Alone Visualization Systems

Outages reported from the AMI system can be visualized in the OMS and/or other systems. Many utilities record an AMI meter's latitude and longitude at installations, which allows them to use stand-alone visualization software to show outages and restorations. Some AMI vendors offer visualization packages as part of their management software. If a system independent of the OMS is used, the stand-alone system can also serve as a business assurance application for an OMS application failure event. These maps are also helpful during large events by providing restoration managers near real-time information about outage and restoration activities .

#### DMS and OMS Visualization

The distribution management system (DMS) and OMS can visually display the location of AMI calls in relation to their associated transformer. The DMS and/or OMS can visualize AMI and customer-reported outages separately, providing valuable information to the system operator.

Visualization of AMI restore messages can also help system operators identify nested outages, which appear as a group of outages surrounded by restored outages.

### Visualization of Islanding

Visualization of outages and restore messages is helpful in identifying downed energized conductors as well as intentional or unintentional islands. In addition, large-area islands and power restore messages can help identify single meters that are improperly energized as a result of customer generation. Visualization of islanding may not be an option for mesh systems because meters that are not part of the island may be required to return messages to the AMI system.

### Initial Customer Communication of an Outage Using OMS

When an outage occurs, the vast majority of customers want to know that the utility is aware of their outage. Most customer communication systems—including voice response units (VRU), web-based forms, text messages, and email—can receive outage status from the OMS and inform customers that their outage is already in the system. Some AMI systems can transmit information about sustained outages to the OMS in under 90 seconds. Quick identification of a sustained outage allows proactive customer communication in which the utility notifies customers about an outage before they attempt to contact the utility.

As a result of mapping errors, proactive outage messaging from OMS predictions can cause incorrect messages. For example, if the customer's location is not accurately represented, the utility might inform customers about an outage that is not affecting them. However, strategies exist that can help ensure that customers receive accurate information. For example, the utility can use OMS-based messaging that requires the customer to initiate contact (such as viewing a web page or listening to a VRU message) before providing outage information. Waiting for a customer to initiate contact reduces the utility's risk of communicating incorrect outage information because customers affected by an outage are most likely to call the utility.

### Initial Proactive Customer Outage Communication Using Only AMI

Outage information sent to customers is generally tied to events in the OMS system. However, the AMI system could generate initial proactive communications. These messages might not include an estimated restoration time because the OMS still needs to evaluate the outage.

A benefit of sending messages based on an AMI sustained outage report is the elimination of errors caused by customers mislinked to the wrong transformers or phase. Such a system may need to be augmented with OMS messaging when SCADA predicts or confirms outages of protective devices with large customer counts. Such augmentation is necessary because most AMI systems are unable to receive 100% of outage messages for large customer events.

### Intermittent Service Problems

Many utilities develop special procedures for single-customer outages that are only reported through the AMI system, such as immediately pinging the meter. Occasionally, operations may ping a meter associated with an AMI-reported single-meter outage and receive a ping response indicating that the meter is energized and has good voltage. AMI systems with meters that can determine whether an outage is sustained or temporary can remove meters that respond to the ping and dispatch them to an individual or department equipped to determine what caused the sustained outage determination (such as a bad meter, connection issues, or cable degradation).

### Customer Main Breaker Issues

Many customer calls are a result of internal breaker issues. If outages from AMI meters consistently create a prediction in an OMS system before a customer calls, the customer communication systems can deliver messages that accurately reflect the customer's service. If the customer's account does not match an existing outage prediction, the system can inform the customer that the utility's data does not indicate an outage and direct the customer to check the main breaker or contact the maintenance department (if the meter is associated with a multifamily account).

Pinging the customer's meter for health and voltage can deliver useful information. If the ping is successful, the customer would again be instructed to check their breaker. (Customers who insist on speaking with a service representative will receive the same information and instructions as customers who communicate with the automated system.) If the ping is unsuccessful, the customer would be informed that their outage is confirmed, and the system would create an outage ticket and follow-up work order to determine why the meter did not report the outage.

## Reliability Indices

The outage record and the outage time stamp can increase the accuracy of reliability indices in several ways to.

### *Single-Phase Outages Modeled as Three-Phase*

AMI-reported outages can be analyzed to highlight reclosers that were modeled as having all three phases open when only one or two were involved in the outage event. Changing a three-phase recloser outage to a single-phase outage can dramatically reduce the number of minutes reported to the system average interruption duration index (SAIDI). 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 can also help correct mapping errors.

### *Outage Associations*

The outage starts times for all meters associated with an outage should be close to the same time. Identifying outages with meter start times outside of an acceptable range can make it possible to identify separate outages associated by the OMS. An OMS will use the earliest prediction as the start time of the outage. For example, consider a transformer outage starting at noon that affects four customers. The outage is predicted in the OMS but not confirmed by an operator. At 2:00 p.m., the feeder serving the transformer opens and creates an outage for an additional 2000 customers. The feeder outage is restored at 3:00 p.m. At 4:00 p.m., customers on the transformer call back and are re-predicted out. The transformer is restored at 5:00 p.m. The following calculation shows the reported customer minutes of interruption (CMI) compared to the significantly lower actual CMI:

Reported CMI = 2004 x (15-12) + 4 x (17-15) = 6020 minutes
Actual CMI = 2000 x (15-14) + 4 x (17-12) = 2020 minutes

A process that analyzes outage start times would flag this event for investigation. By correcting the start time of the larger event, 4000 minutes would be removed from the reliability index.

## Identification of Overloaded Hydraulic Reclosers

While momentary outages may confuse an OMS, they are useful when 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 return; after a short period of time, the remaining load returns and causes the recloser to trip again. In a high-load weather event, the trip and reclose sequence can happen many times. After weather events that increase demand, momentary outages can be plotted on a map to identify hydraulic reclosers that are operating due to load. The map plots customers who experienced momentary outages that exceed a utility-selected number during the weather event. Pockets of outages that appear behind hydraulic reclosers indicate a recloser that was probably operating due to load. Without AMI, these operations may go unnoticed until the recloser fails or customers complain.

## Identification of Downed Energized Conductors

Faults that are not cleared by standard protective devices pose a risk to the public. Utilities have long sought effective ways to identify events that leave the public exposed to energized downed conductors. Recent EPRI work (report 3002010163) suggests that some of these events can be reliably detected and located using AMI with SCADA and OMS.

A manual process of evaluating predicted OMS outages associated with closed SCADA devices has proven effective at identifying possible hazards. But, most utilities' protective devices (such as hydraulic reclosers and fuses) do not have SCADA monitoring. Thus, there is a need to develop an automated process to use data from multiple sources to identify events on non-SCADA devices that might create a public hazard.

Designing and implementing pilot programs will help the broader industry gain experience with the integration challenges associated with detecting downed conductors. EPRI has an active supplemental project to coordinate and capture information from multiple utilities that are piloting AMI-based technology. CPS Energy has joined the supplemental project and deployed a pilot system. The CPS pilot and other EPRI research associated with detecting high impedance faults are discussed in EPRI report 3002012882, *Modern Approaches to High-Impedance Fault Detection.*

### *Pilot at CPS Energy*

CPS Energy has implemented a system that uses AMI to automatically check for and locate downed conductors. Their system, known as Hazard Identification using AMI (HIAMI), is the first known use of AMI to automatically detect downed conductors by pinging, and was enabled for the entire CPS Energy system in August, 2018. HIAMI checks every reported outage downstream of fuses and reclosers. At the time this report was written, the HIAMI had not identified any downed conductors although several events were triggered.

Figure 1-9 shows an early event that HIAMI detected where a location was estimated with high confidence. The red marks indicate transformers with meters that did not respond to pings. The HIAMI data was not analyzed until days after the event and the outage notes were not descriptive, so what happened in this case is uncertain, but the pattern matches a broken conductor at the start of the side tap.

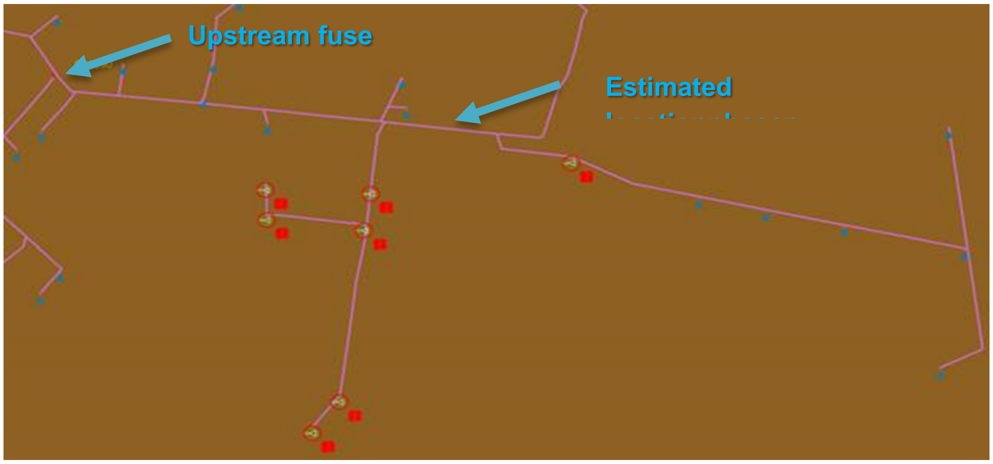


**Figure 1-9**
**Example of a HIAMI event at CPS Energy where a location was identified**

The main components in the CPS Energy control center are:

- ABB outage management system
- Silver Springs AMI system
- IBM middleware to provide an interface between the AMI and OMS

The AMI system is integrated into the OMS. Power-off notifications from meters feed into the OMS system, and control center operators can also ping meters through the OMS.

HIAMI is implemented on the same server as the OMS system. All HIAMI interactions with other systems occur through connections to the ABB OMS. HIAMI is composed of the following pieces of code:

- hiami.sh is a small shell script to run hiami.sql to check for new outages. If any new outage events are found, the script then runs hiami.py. This script is triggered to run periodically.
- hiami.sql is a query to check for new outages.
- hiami.py is a Python script that runs on the OMS server and handles most of the processing. It uses database queries and procedure calls to interact with the ABB OMS, and relies on the Python package cx_Oracle to interface with the OMS database. The Python package NetworkX is part of the tracing algorithms.

HIAMI only needs to interface with the OMS, which has outage information in database tables and can initiate pings to meters and record ping responses. HIAMI uses the OMS' public programming interface to initiate pings as an Oracle procedural call.

The HIAMI algorithm contains the following steps:

- Look for new outages in the OMS outage table or outages with updated phasing or devices (to handle rolled-up outages).
- For each new outage in or on a fuse or recloser, run the following. Each outage is processed in parallel.
  - Pick out the device ID.

- Initiate a downline subtree trace in the OMS to collect the circuit information past the protective device.
- Pull the results from the subtree trace and convert to a network model. Remove open points so the circuit is strictly radial. If the network model has less than X feet of overhead line, stop the algorithm (to skip checking circuit sections that are mostly underground).
- Run a trace on the network model to find the bellwether transformer(s). This algorithm is adapted from the code in Appendix B.
- Look up the meters on the bellwether transformer(s).
- Initiate pings to all meters on the bellwether transformer(s).
- Repeat the following up to five times.
  - Wait 30 seconds.
  - Count the number of pings that responded.
  - If the count is greater than zero, do something.
- Repeat the following up to five times.
  - Wait 30 seconds.
  - Count the number of pings that have responded.
  - If the count is greater than zero, exit the loop.
- If the count is greater than zero, run the following:
  - Run follow-up pings to help identify location.
  - Wait for responses from follow-up pings (up to 2.5 minutes).
  - Run the algorithm to estimate location and confidence in location.
  - Add an entry on this event to a special table in the OMS. Every new entry in this table triggers an email to the main CPS Energy developer for action and review.

Every flagged outage includes the following information:

- Outage ID
- Timestamp
- Device
- Region
- Circuit
- Device phasing
- Outage phasing
- Location estimate (a line segment identifier)
- Location ratio indicator
- Number of bellwether meters
- Number of bellwether meters that responded as up

The events most likely to involve a broken conductor are those where the outage phasing only involves one phase; the location estimate is given; the location ratio indicator is close to 1.0; and more than one bellwether meter responded to the ping.

It is important to distinguish between AMI meters and non-AMI meters in the HIAMI algorithm. When searching for bellwether transformers, HIAMI only considers transformers with AMI meters.

Several lessons are being learned about how to test HIAMI. To allow tests on outages in different scenarios, it is important that all systems testing HIAMI have pingable AMI meters. Using restore outages on the production OMS has been beneficial for testing tracing and ping capabilities. HIAMI can be run manually on any outage still in the OMS, including restored outages. When HIAMI is run on a restored outage, the bellwether meter pings return as up, and follow-up pings are sent to meters on all transformers past the protective device. CPS Energy has experienced high success rates for pinging with HIAMI.

The CPS Energy pilot program is confirming several uses for HIAMI beyond detecting downed conductors, including using HIAMI to help operators identify both false outages and false rollups.

False outages can occur when the OMS rolls up some outages to devices in cases where there are no real electrical outages. This can happen as a result of customers incorrectly reporting outages grouped in one area, and as a result of momentary interruptions that allow AMI power-off notification past filtering in the AMI outage system. When HIAMI runs on these outages, the bellwether meter(s) will ping up, so HIAMI sends follow-up pings to all transformers. The HIAMI location estimator will fail to locate anything because there is no string of outaged transformers at the end of a section. The lack of a location and the follow-up ping responses prove to the operator that there is not an outage on this section, and they can clear this outage.

False rollups can happen when there are multiple separate outages in an area, including both real and falsely reported outage events. If operators can identify these, they can push outages upstream. The HIAMI system will catch most false rollups because the location estimate will indicate low prediction confidence. Outages in a false rollup will be scattered instead of concentrated at one location. A graphical view of the transformers with outages will allow operators to quickly identify a false rollup and push the outages back down.

Another source of false alarms is data errors, including graphic information system (GIS) errors that generated false HIAMI alarms. A common error identified since HIAMI became operational results from incorrectly mapping a meter to the bellwether transformer. If the meter is upstream of a fuse that operated, the bellwether transformer will ping up when HIAMI runs, and the location algorithm will indicate a break just past the bellwether transformer. Figure 1-10 shows an example of a meter that was identified as being on the bellwether transformer but was likely on the transformer just upstream. This situation demonstrates the value in pinging multiple meters on the bellwether transformer and recording both the number of bellwether meters that reported up and the number that did not respond. If only one of five bellwether meters reported up and all other transformers on that section are showing as down, a data error is likely.

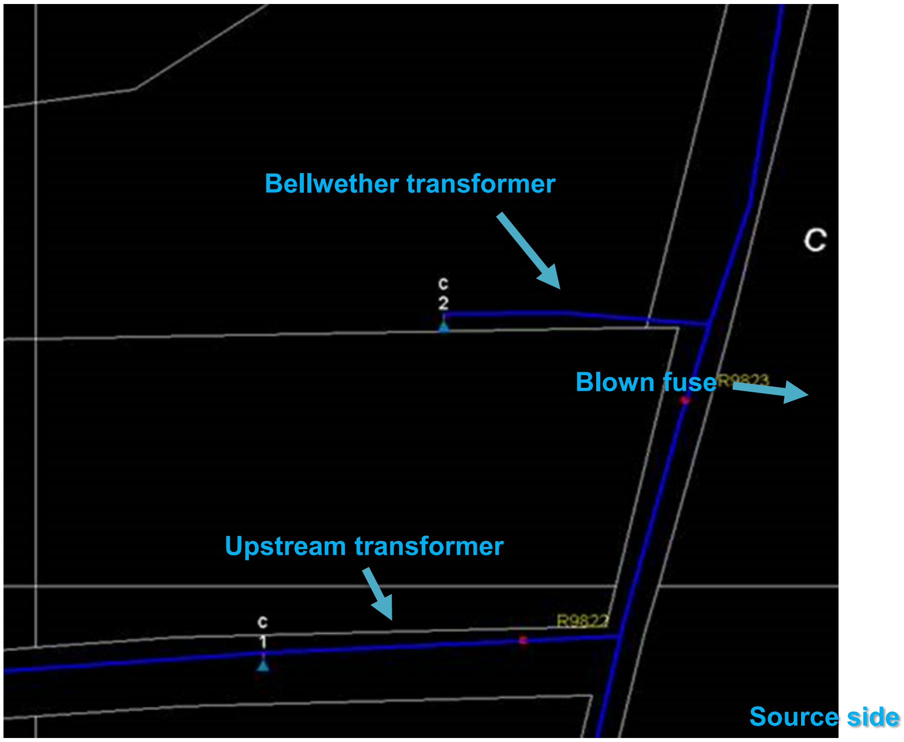


**Figure 1-10**
**False alarm from a meter mapping error**

CPS Energy will continue to run HIAMI to collect information on how well it works, identify issues in operations, and determine how to best integrate it into their operational processes. CPS Energy is considering a number of options to improve HIAMI functionality, including:

- *SCADA integration*. Currently, the OMS system is not connected to SCADA. If SCADA were connected to OMS, HIAMI could check status information on SCADA reclosers to identify mismatches between OMS and SCADA status.
- *Visualizati*on. Customer outage calls and AMI outage messages are graphically displayed in the OMS, but HIAMI ping results are not. Visualizing the results of follow-up pings would allow operators to more quickly understand the outage pattern and determine whether a downed conductor is likely or if it is a false alarm resulting from a data issue or false rollup.
- *Web interface*. A web dashboard with information on HIAMI events would allow control center managers and operators to better respond and manage these events.

## Substation High-Side Transformer Fuses

Many substations use fuses to provide transformer protection. If the transformer uses delta-wye configuration, a single blown high-side fuse will cause low voltage on two phases of the distribution system. The phasor diagram is shown in Figure 1-11. A blown fuse on Phase 2 of the substation transformer will affect the voltage on phases B and C of the distribution system.

Since Va + Vb + Vc = 0 and Va is nominal, the voltage at the meter for customers connected to phase B or phase C will be near 50% of nominal.

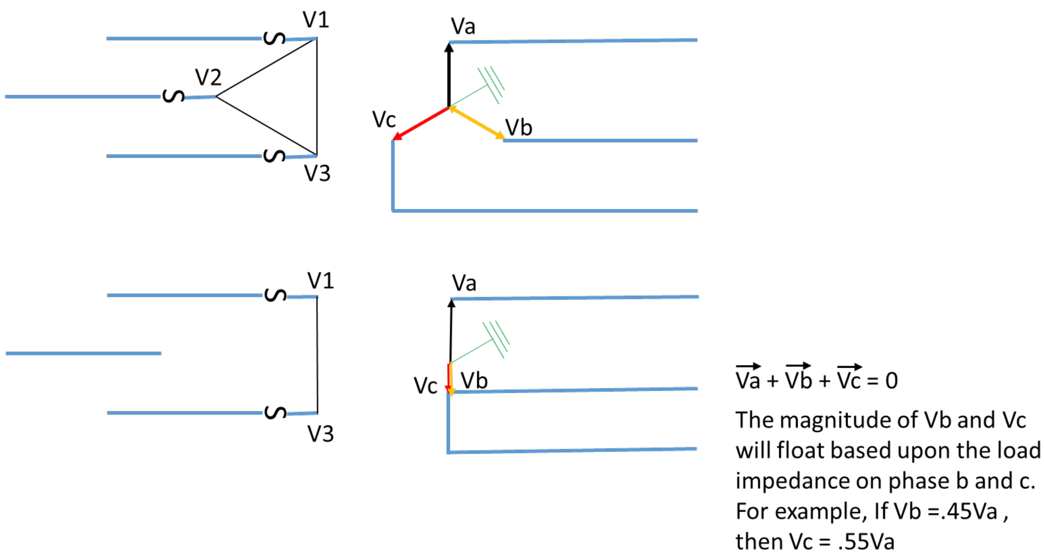


**Figure 1-11**
**Vector representation of high-side transformer fuse open**

Since meter outage threshold varies by make and model, some meters may report an outage while others report a low-voltage alarm. If outages are reported, the OMS will create a predicted outage on the feeder breaker, or create multiple fuse and transformer outages if the breaker is not allowed to be a predicted device. (Predicted devices are determined by an OMS setting used by utilities with a data connection between SCADA and the OMS). In both cases, the DSO will be prompted to investigate.

If low-voltage AMI alarms are not imported into the OMS, the DSO might not know about the condition until customers call. However, if customers only report dim lights, an outage might not be created in the OMS.

Table 1 2 illustrates Georgia Power's outage threshold for their deployed meters.

**Table 1-2**
**Georgia Power Outage threshold table for meters they deploy**

| 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 |

*All meters programmed with a six cycle (minimum) delay when voltage drops to above levels
*Nominal voltages selected based on meters primary use on our system

Note that only the Landis+Gyr meters have a voltage threshold high enough to detect a blown fuse as an outage.

# 2

# UTILIZING OTHER AMI MESSAGES AND FUNCTIONS

## General AMI Functions

AMI meters can provide a significant amount of data to operations. Some of this data can be used in near real-time while other data might be obtained during normal data collection schedules. In 2012, EPRI tabulated the data captured from a group of AMI meters. Table 2-1 contain some of the available data. The data varies by meter manufacturer and by the type of communication module in use. In general, using a different meter manufacturer and AMI system providers will result in fewer available features. Table 2-1 also contains information about available intervals. The interval figure provides the range at which other values can be averaged. For example, neither meter B1 or E1 are suitable for obtaining a 1-minute average voltage because they can only return 15-minute average voltages.

**Table 2-1**
**List of 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 | | | | | | | | | | ✔ |

**Table 2-1 (continued)**
**List of parameters provided by sample meters**

| Meter | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Designator** | **A1** | **B1** | **C1** | **D1** | **E1** | **A3** | **B3** | **C3** | **D3** | **E3** |
| **Steady-State Parameters** | | | | | | | | | | |
| 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 + |

## Identification of Transformer Windings Shorts and Regulator Misoperation

Utilities have shown success at identifying failed or failing equipment based upon information from AMI meters. Average voltage information can be used to identify transformers with windings shorted, and can also identify regulators and switched capacitors that are not operating properly. If voltage information is combined with circuit data, the type of problem can be identified and trigger a script to automatically create and dispatch repair. Voltages that are out of range on a single meter are dispatched as a bad meter, while 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.

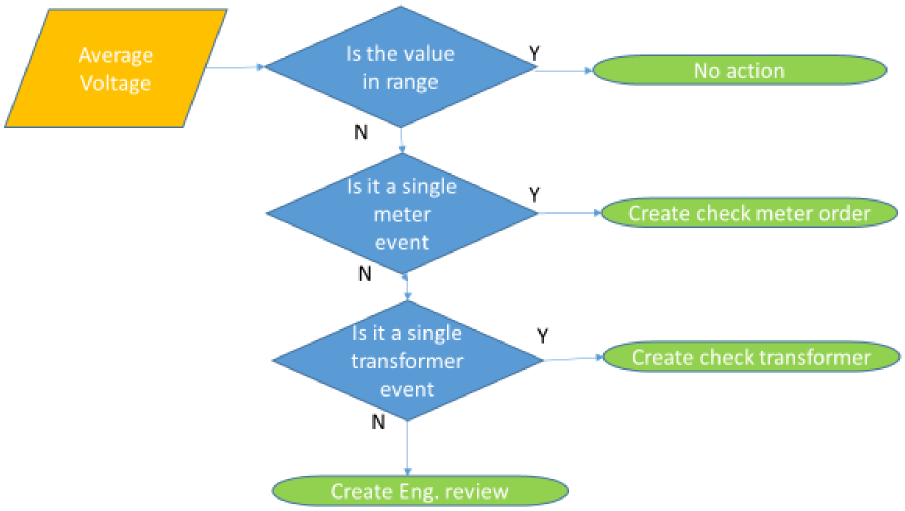


**Figure 2-1**
**Flow chart for sustained voltage out of range**

### Near Real-Time Voltage Visualization

If the average voltage of a meter is outside of the normal band but 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 that displays both high- and low-voltage readings. Once the average voltage is within the acceptable voltage band, the meter sends its voltage reading again and is removed from the heat map. Some meters may be able to perform 1-minute averages while other are limited to 4-hour averages. The metrology portion of the meter determines the length of time over which the meter averages the voltage.

### Voltage Feedback for Conservation Voltage Reduction (CVR) Systems

Voltage data from AMI meters can provide feedback to CVR systems [4] (Dominion 2012). The CVR system can ping identified bellwether meters after each voltage step reduction. If the ping indicates that the voltage is close to the established limit, the CVR system does not perform another step reduction. AMI makes additional CVR reductions possible. Systems that depend upon planning studies to determine the amount of reduction are inherently conservative to avoid creating voltage events below the standard limits. AMI meters also account for actual secondary voltage drop. Many planning models estimate a secondary voltage drop. In lieu of selecting bellwether meters, the CVR system can monitor low-voltage alarms to create the low limit of reduction.

### Analyzing Feeder Voltage Profile

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

- During solar generation hours, the series with the lowest voltage becomes the series with the highest voltage. 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 and capacitor management is being considered.
- The illustration shows areas where the transmission voltage might be high or where the substation transformer may be set on the wrong tap to deliver nominal voltage.
- The data is consistent enough to be evaluated by back-office application to identify circuits that are approaching or exceeding voltage limits. The same process would identify circuits with low voltage.
- AMI voltage data alone may be enough to identify individual solar installations.

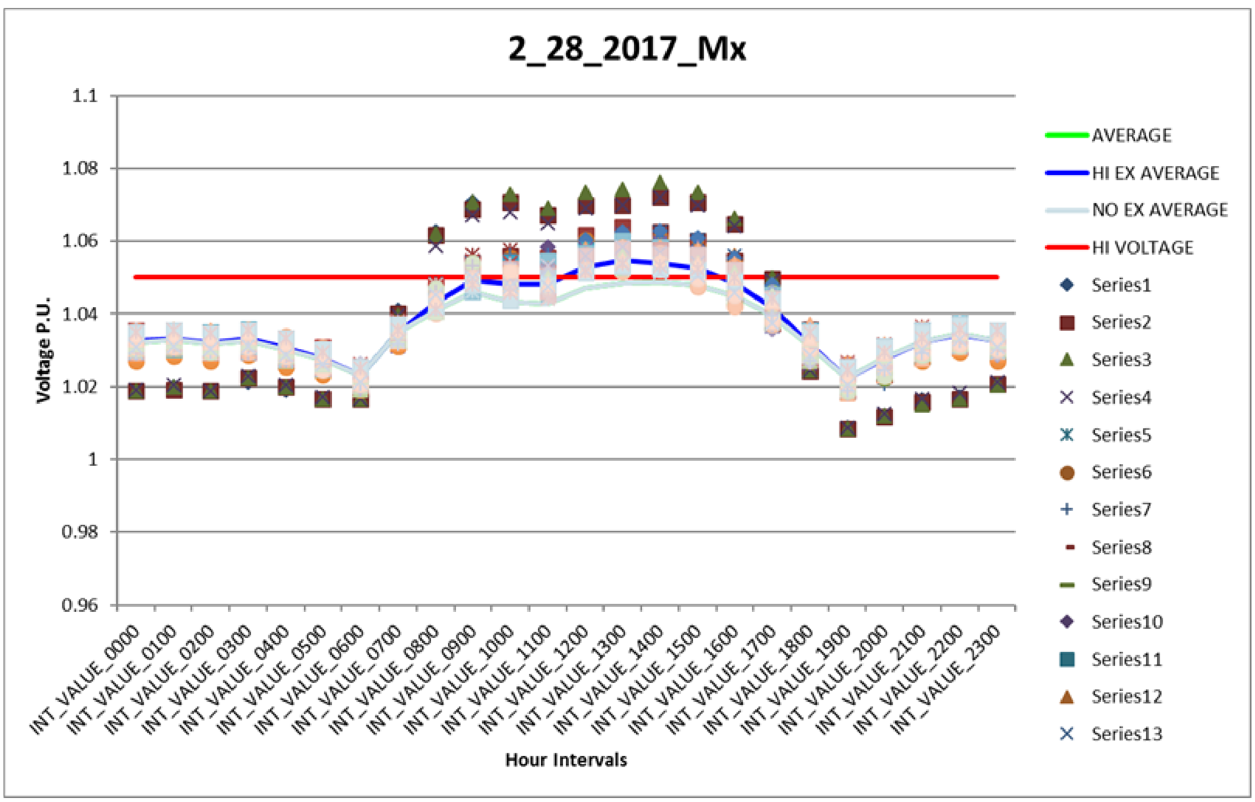


**Figure 2-2**
**Arizona Public Service plot of voltage profiles**

## Capacitor Health and Control

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

Figure 2-3 illustrates how an 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.

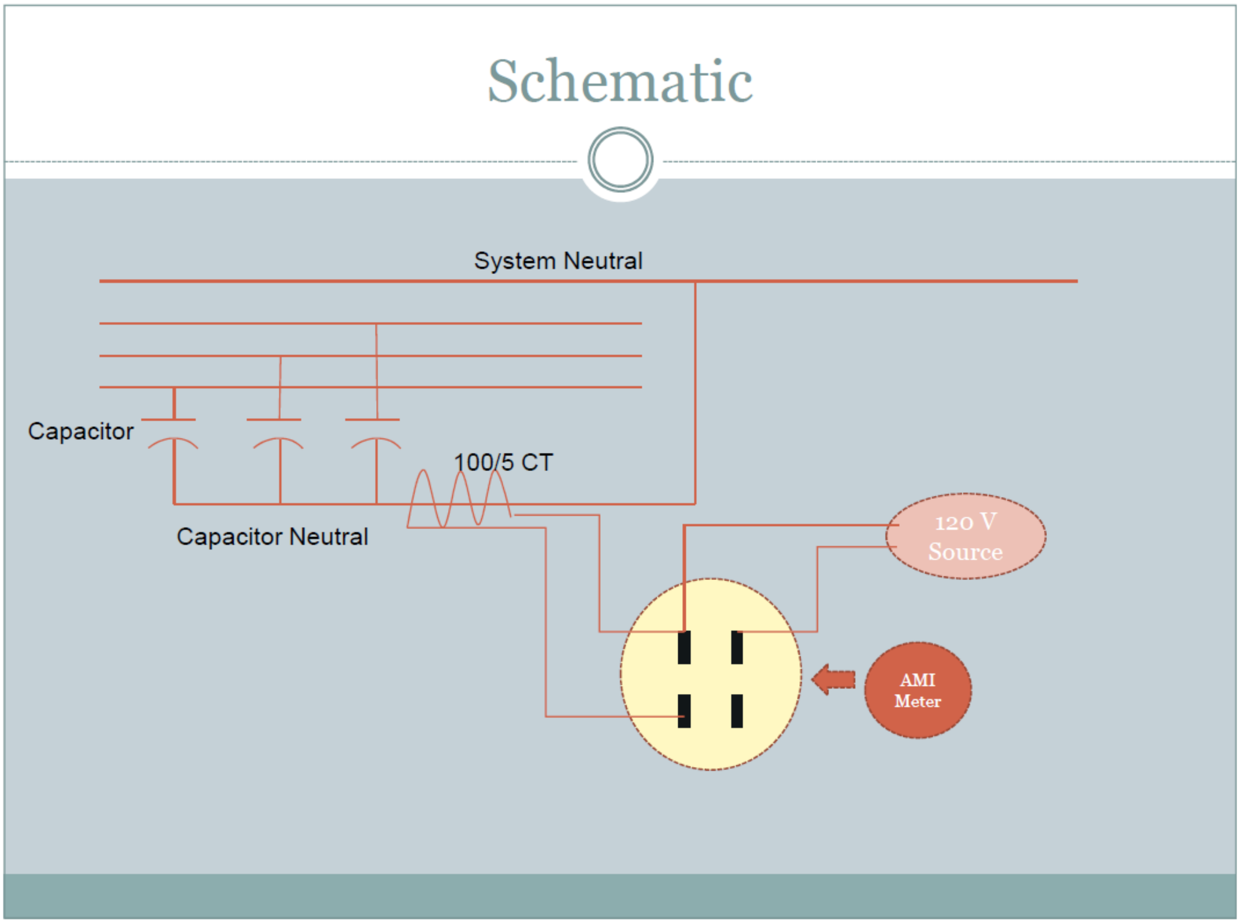


**Figure 2-3**
**AMI capacitor monitor schematic**

Following the AMI-based capacitor monitor's success in identifying health issues, a second meter adapter was created. The second meter has electronics to monitor and control a switched capacitor based upon the status of an AMI meter with connect and disconnect capabilities. The electronics in the adapter monitor the load spade of the AMI meter. If the load spade is energized, the electronics send a close pulse to the capacitor switches after a delay. If the load spade becomes deenergized, the electronics send an open pulse to the capacitor switches after a delay. The AMI meter becomes the monitor and controller, and completely replaces the capacitor control. This type of monitor and control depends upon a centralized volt/var system to control the position of the AMI meter, which in turn controls the position of the capacitor switches. Georgia Power owns the patent for this process, and the adapter can be purchased. A more detailed article about the process is located in the February, 2013 edition of T&D magazine.

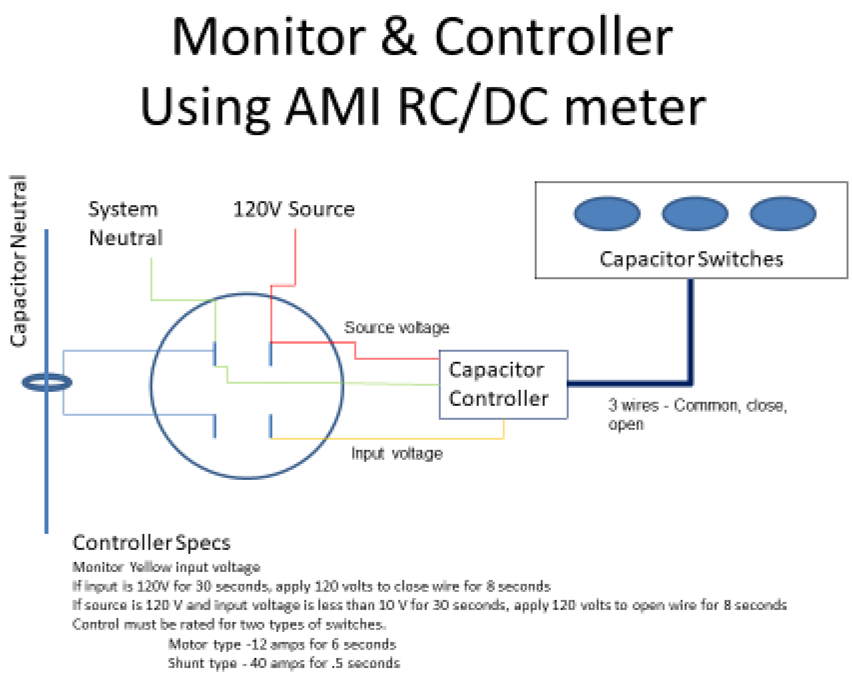


**Figure 2-4**
**AMI capacitor monitor with control module**

### Identification of Mapping Errors

Customers increasingly desire more information about their services, including proactive communication by the utility about outages. To provide accurate information, the relationships between the customer's meter, the service transformer, the phase to which the transformer is connected, and the protective devices are critical. 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 OMS systems allow the system operator to move the AMI meter to a different transformer. This move is then incorporated into the database, linking 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. Since every mislinked meter creates an outage event that operators must manage, it is in the operators' 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 with 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. AMI meters report these events as an outage.

### *Using Zero Crossings*

A recent development is measuring the time to a zero crossing to identify a meter's phase. In a tower-based AMI system, a single tower command can be sent to all meters within the tower's range (see Rhoades 2018). The meters respond to the command by measuring the amount of time between receiving the command and the occurrence of the next voltage zero crossing. The time value is included in the data returned at the next reading. Meters are then grouped by the time captured. In general, three groups of time are created that represent the three different phases. These groups are then compared to transformer linkage and the mapping databases to identify meters that do not match their current linkage. Phase identification can be performed by comparing the time to known bellwether meters, or by grouping meters and applying changes based upon the assumption that most meters within the GIS are correct. By assuming that most meters are correct, he entire process can be scripted and periodically executed to ensure accurate customer linkage. Each group will be four to five milliseconds apart.

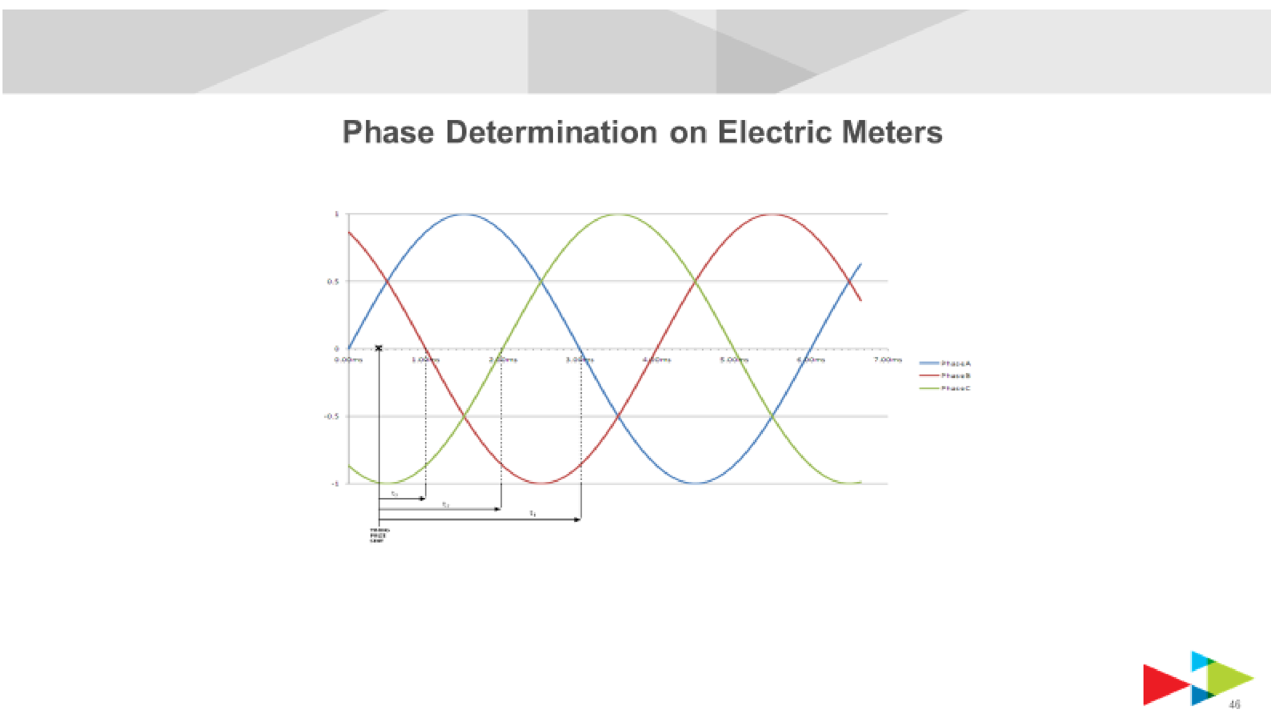


**Figure 2-5**
**Time to next zero crossing from Alabama Power**

## Test 3 Results

| Feeder Number | Meters Matching GIS | Meters Not Matching GIS | Meters Not Reporting | Total Meters | Error |
|---|---|---|---|---|---|
| 1 | 490 | 15 | 149 | 654 | 2.20% |
| 2 | 1188 | 255 | 484 | 1872 | 13.62% |
| 3 | 760 | 68 | 428 | 1256 | 5.41% |

**Figure 2-6**
**Alabama Power phase identification test**

Not all AMI meters at Alabama Power can perform the zero crossing measurement. The meters that can are manufactured by the same company that manages the communication system, and the AMI metrology and the communication module are integrated. The meters that are built for interoperability cannot perform zero crossing measurement and are represented in Figure 2-6 as “meters not reporting.”

### *Using Voltage Data*

Voltage data from feeders with single-phase regulation have been analyzed to determine if sufficient grouping can be done to identify phases. EPRI published a report in October 2018 with the following key findings:

- Correlation and regression models performed reasonably well for the six feeders evaluated using only voltage measurements.
- Intentionally creating a change in voltage on one phase reduced the amount of data needed for phase identification. 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.

### Over- and Underutilized Transformers

Many utilities rely on AMI usage and demand data to identify over- and underutilized transformers. The larger the transformer, the greater the value in preventing failure due to overload or replacing it with a smaller transformer. The process is straightforward for transformers that serve only one customer. Each utility has criteria for the percentage above or below nameplate capacity they are willing to accept. The same process can be applied to smaller transformers by summing the AMI meters that are linked. This process can identify overloaded transformers and may also identify transformers that have many mislinked meters.

### Past 24-Hour Transformer Loading for Replacements

Extreme weather events including severe heat or cold can cause many transformer outages. Access to past 24-hour loading data for transformers enables operations to make an informed decision whether a transformer should be replaced or simply refused. Because refusing a transformer is much faster than replacing a transformer, readily available loading information can dramatically impact restoration time.

### Individual Solar Distributed Energy Resource (DER) 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 base load projections which can be used to approximate generation size. The required data points and specific algorithms for this task are being determined. If successful, a utility will be able to identify customers with rooftop solar panels who did not register their installation.

### Identification of Individual Electric Vehicle (EV) Charging

By looking for changes in voltage, load and power factor, a standard residential AMI meter may be able to identify the presence of electric vehicle 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 that did not register their installation with the utility can be identified, planned for and educated about any rates that would encourage off peak charging. A detailed study is located in EPRI report 3002000582.

### Identification of Feeder Solar DER

By plotting a feeder’s average voltage, feeders with high voltage away from the substations can identify the feeders with enough solar penetration to impact the voltage profile. This can also be accomplished by comparing the average voltage reading of meters close to the substation (V1) with those further down the line (V2). Circuits are flagged when the difference in average voltage (V1-V2) exceeds a predetermine negative number.

### Identification of Customer Heating Method

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

In 2017, Dominion installed a data repository designed to capture and store the vast amount of AMI- generated data. Using interval data from residential meters, Dominion was able to successfully group customers by heating method by grouping customers based upon their sensitivity to temperature. Dominion presented their findings at the CIGRE US National Committee 2018 Grid of the Future Symposium in a Presentation titled Residential Customer Clustering at Dominion Energy: Towards Big Data Analytics. While AMI provided 30-minute usage resolution, Dominion is performing the same analytics on monthly data to determine whether AMI resolution is necessary for successfully identifying heating methods.

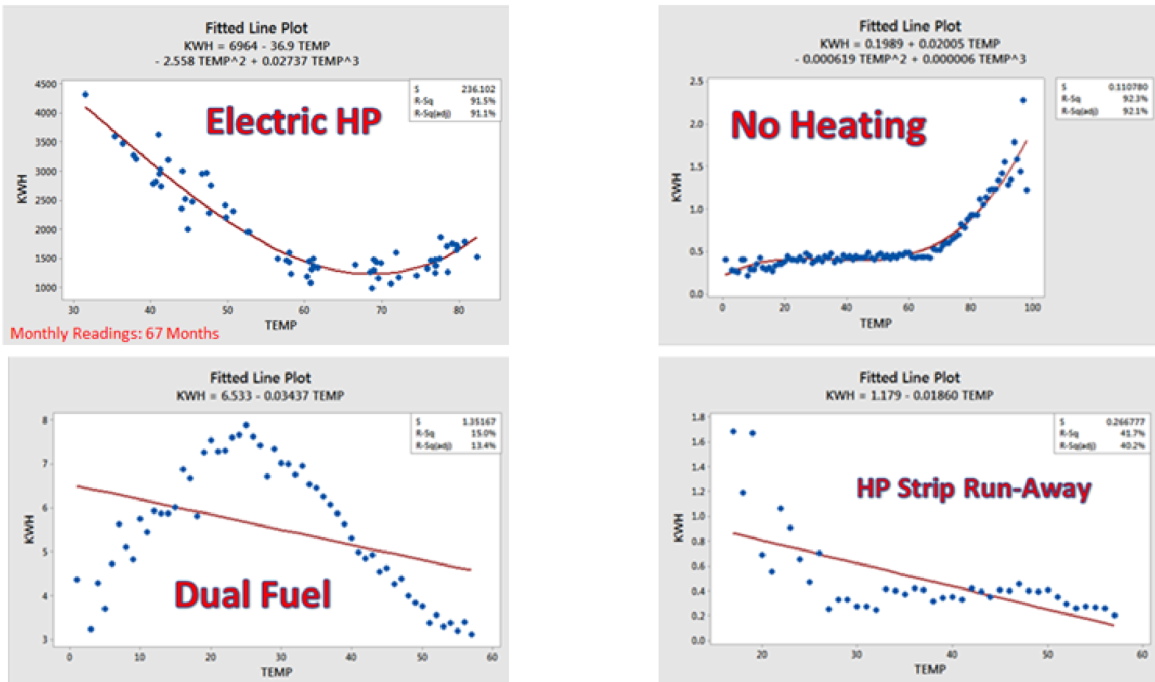


**Figure 2-7**
**Identification of heating method at Dominion Energy**

### Step Restoration with Reconnect / Disconnect Meters

If meters with built-in disconnects 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. Possible causes of temporary overload conditions include cold load or the disconnection of DER during the disturbance. The logic to disconnect could include a temperature variable so that the disconnect only occurs at high or low temperatures. This function would extend an outage, but the extension would be minimal and only occur during high-load periods. A wait time of two minutes would be sufficient to allow DER to reconnect. A longer wait time might be needed to mitigate cold-load issues. If all residential meters have disconnect ability, using a random number (within a predefined range) for the wait time can prevent all the meters from reconnecting at the same time.

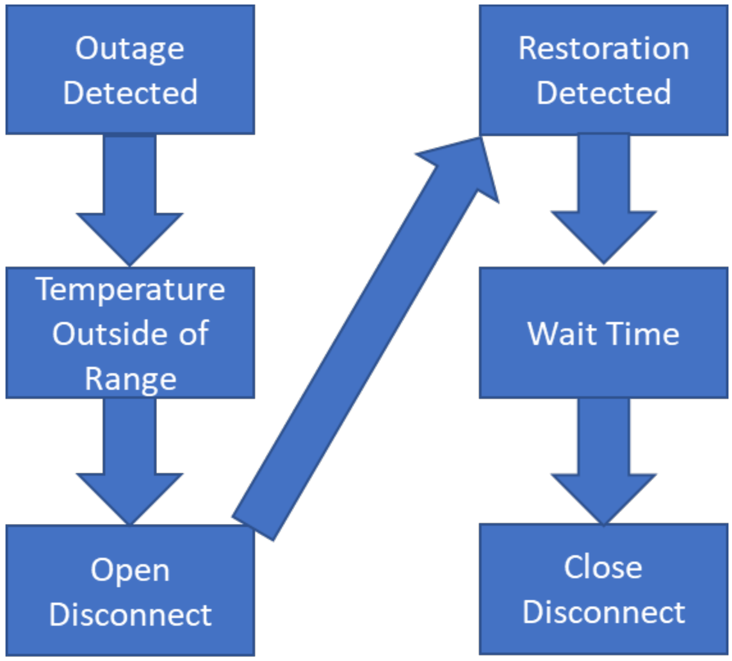


**Figure 2-8**
**Step restoration using internal meter disconnect**

### Under Frequency Load Shed with Reconnect / Disconnect Meters

Meters with a built-in disconnect switch can mitigate generation disturbances by opening for under frequency. The meter's under frequency pickup is set to open the meter 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. After disconnecting for under frequency, the meters must receive a close command from the AMI system before reconnecting the load. While AMI under frequency can be designed to operate faster than substation-based relays, it does not mean that substation-based under frequency will be eliminated. However, if substation-based under frequency remains in place, the substation relays are the only devices which would be periodically tested to meet reliability requirements. The system developed to close the meters when 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 disconnected for auxiliary reasons.

### Targeted Load Shed with Reconnect / Disconnect Meters

Meters with a built-in disconnect switch can 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 upon the desired KW reduction or select meters by feeder. By using AMI meters as the disconnect, the circuit can remain in service for critical loads and important services. Upon activation, the meters must receive a close command from the AMI system before restoring load. Because load shed events often result in rolling blackouts, the selected meters must be organized to facilitate reconnection. If self-contained meter load is insufficient to allow a second block of disconnects, the utility may 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 thus limits its ability to identify neutral problems. However, three-phase meters have a neutral connection and have proven effective at identifying phase to neutral voltage swings that indicate corroded or loose neutral connections. Utilities have successfully created software applications that seek loose neutral conditions associated with C&I meters.

### Current Transformer Issues (Three-Phase Meters)

The data from three-phase meters can be analyzed to identify current transformer problems as well as any wiring errors associated with potential or current transformers. Because these errors are normally associated with large customers, failing to identify these issues can result in lost revenue due to inaccurate metering. Utilities have established unmonitored processes to identify data abnormalities that indicate onsite construction or material issues.

### SCADA Alternative

Before pad-mounted 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 12kV distribution system. This type of installation might require calling out a first responder with different skills than one 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. But, the cost of adding SCADA to old substation-based equipment, which usually has electromechanical relays, can be very expensive.

As an alternative to installing SCADA, utilities begun monitoring the C&I three-phase meter to identify outages at these facilities. Because C&I meters are constructed differently than other AMI meters, they may not be able to use the same processes to communicate information. In Table 2-1, which contains a list of parameters provided by sample meters, meters A3 and C3 cannot indicate outages or low voltage. These meters require a back-office application to analyze data collected from normal polling to identify low voltage and create an outage event. In addition, C&I meters without internal stored energy stop communicating any data when power is lost. To address this issue, utilities rely on back-office systems to convert multiple failed communication attempts into an outage. If communication fails multiple times, the system might have to wait several minutes before converting failed communication attempts into an outage message.

The meters B3, D3 and E3 in Table 2-1 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
# REFERENCES

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*Use of Smart Meter and SCADA Data to Predict Phase Connections and More*. EPRI, Palo Alto, CA: 2018. 3002013761.

*Automated Discovery of Plug-in Electric Vehicle Charging Using AMI Meter Data*. EPRI, Palo Alto CA: 2013. 3002000582.

# A
# APPENDIX

## Past AMI-Related EPRI research

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| Call Center of the Future | 2018 | 3002013920 | https://www.epri.com/#/search/3002013920/ | DMD |
| This report surveys the currently most widely used advanced meter application protocols and examines what would be required to create a single unified standard. It gives an overview of the technical attributes of the candidate standards, DLMS/COSEM and ANSI C12.22, and describes a plausible path by which the industry might arrive at a single world standard. | 2018 | 3002013398 | https://www.epri.com/#/search/3002013398/ | 161F |
| Test tool built with inexpensive off-the-shelf components allows users to test and troubleshoot Wi-SUN-compliant RF communications devices. | 2018 | 3002010501 | https://www.epri.com/#/search/3002010501/ | 161F |
| AMI Application Readiness | 2017 | 3002006204 | https://www.epri.com/#/search/3002006204/ | DMD |
| Dynamic Reliability Metrics | 2016 | 3002008801 | https://www.epri.com/#/search/3002008801/ | DMD |
| Outage Awareness Use Cases | 2016 | 3002008801 | https://www.epri.com/#/search/3002008801/ | DMD |
| Identifying Load and DER Anomalies | 2016 | 3002008800 | https://www.epri.com/#/search/3002008800/ | DMD |
| Detecting Overloaded Transformers | 2016 | 3002008799 | https://www.epri.com/#/search/3002008799/ | DMD |
| Meter and Transformer Phase Validation | 2016 | 3002008797 | https://www.epri.com/#/search/3002008797/ | DMD |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report provides information on AMI and DSCADA applications to inform the business case for adoption. Ten applications are discussed, each of which are considered high value/interest. | 2015 | 3002007029 | https://www.epri.com/#/search/3002007029/ | DMD |
| Fault-Location Analytics | 2015 | 3002007029 | https://www.epri.com/#/search/3002007029/ | DMD |
| This report provides information on AMI and DSCADA applications to inform the business case for adoption. Ten applications are discussed, each of which are considered high value/interest. | 2015 | 3002006992 | https://www.epri.com/#/search/3002006992/ | DMD |
| Individual Customer Outage Notifications | 2015 | 3002006992 | https://www.epri.com/#/search/3002006992/ | DMD |
| Optimizing Estimated Restoration Time | 2015 | 3002006992 | https://www.epri.com/#/search/3002006992/ | DMD |
| This technical update report examines some of the opportunities and hesitations for a utility to examine when considering implementing an open AMI system, including such issues as responsibility for integration of the system components, which entities provide the required maintenance expertise, and some potential economic effects on the industry. | 2015 | 3002006917 | https://www.epri.com/#/search/3002006917/ | DMD |
| Using AMI to Detect Energy Theft | 2015 | 3002006892 | https://www.epri.com/#/search/3002006892/ | DMD |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This paper describes the current state of AMI requirements and highlights five specific areas that are essential to consider in order to future-proof the system. | 2015 | 3002006738 | https://www.epri.com/#/search/3002006738/ | DMD |
| This document describes the first edition of a reference implementation of the IEEE 802.15.4g / Wi-Sun communication standard. EPRI developed this reference software during 2015 to provide the market with a vendor-neutral implementation and utilities with a baseline against which vendor products can be evaluated. | 2015 | 3002005587 | https://www.epri.com/#/search/3002005587/ | 161F |
| This document is a guidebook for utilities that details a recommended practice for AMI system prognostics and health management (PHM). The procedures outlined herein are intended to guide utility test procedures that provide insight into the remaining useful service life of AMI systems. | 2015 | 3002005471 | https://www.epri.com/#/search/3002005471/ | 161F |
| AMI Applications Member Survey | 2015 | 3002004682 | https://www.epri.com/#/search/3002004682/ | DMD |
| PEV Load Pattern Analysis | 2014 | 3002004903 | https://www.epri.com/#/search/3002004903/ | P18 |
| Managing AMI and Other Big Datasets | 2014 | 3002004085 | https://www.epri.com/#/search/3002004085/ | DMD |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report provides test results for an evaluation of ANSI residential solid-state electricity meters. The testing was performed to determine whether the accuracy of these meters is impacted by conducted noise in the 2KHz to 150KHz frequency range. | 2014 | 3002003249 | https://www.epri.com/#/search/3002003249/ | 161F |
| This report introduces the idea of utility devices becoming "platforms" rather than just "products." Where a product would have fixed functionality for its service life, or functionality that only the manufacturer can update, a platform would be open to the owner, and available to perform new functionality as enabled by applications (apps) that the owner may choose. This report provides an update on an initiative to define and demonstrate an open application platform for advanced meters. | 2014 | 3002002859 | https://www.epri.com/#/search/3002002859/ | 161F |
| This document provides the results of a research project aimed at addressing a concern in the advanced metering infrastructure (AMI) and outage management system (OMS) family of use cases. | 2014 | 3002002858 | https://www.epri.com/#/search/3002002858/ | 161F |
| This study evaluated the effect on solid state meters due to hot socket conditions and considered the potential for internal temperature sensors for detection. | 2013 | 3002001298 | https://www.epri.com/#/search/3002001298/ | 161F |

| Description | Year | Report Number | Report Link | Source |
| --- | --- | --- | --- | --- |
| There is a clear need in the industry to understand the applications in which advanced metering infrastructure (AMI) systems and data can be used. This white paper investigates how utilities that have implemented AMI systems are actually using these systems. | 2013 | 3002001098 | https://www.epri.com/#/search/3002001098/ | 161F |
| This report presents the results of a survey conducted by EPRI's IntelliGrid program in October 2013 of utilities that have deployed advanced metering infrastructure (AMI) systems on how they actually use these systems. These utilities represent more than 50 million meters deployed. The companies began deploying their systems as early as the late 1990s to as recently as 2013. | 2013 | 3002001077 | https://www.epri.com/#/search/3002001077/ | 161F |
| This project examines issues related to establishing and maintaining reliable long-term communication with end-use devices for load management purposes. The impetus for this project was a broad set of challenges encountered by utilities conducting pilots and projects based on potential new communication technologies and architectures. | 2013 | 3002001057 | https://www.epri.com/#/search/3002001057/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| Most of the advanced metering infrastructure (AMI) systems available today are proprietary systems that lock utilities into a single vendor, limit flexibility, and raise costs. This report describes a roadmap for developing genuinely interoperable AMI. | 2013 | 3002001043 | https://www.epri.com/#/search/3002001043/ | 161F |
| Detecting PEVs Using AMI Data | 2013 | 3002000582 | https://www.epri.com/#/search/3002000582/ | P18 |
| This report is intended to assist personnel responsible for cyber security in AMI deployments. The methodology presented provides a walkthrough for a process that can be used to leverage an existing body of work to assess cyber security in an AMI system. This methodology can assist in identifying vulnerabilities, threats, impacts to the AMI system, and guidance for mitigating the overall level of risk. | 2013 | 3002000389 | https://www.epri.com/#/search/3002000389/ | 161F |
| This technical update provides utilities with an overview of recent activities within AEIC and their subcommittees and working groups. | 2013 | 1024390 | https://www.epri.com/#/search/1024390/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| In 2013, the IntelliGrid program will launch a project to document the applications, impacts, value chains, benefits, and costs of AMI deployments. This paper provides background information for this project by defining the stakeholders in an AMI deployment, compiling a list of possible applications for AMI systems and determining the impacts of these applications. | 2012 | 1026826 | https://www.epri.com/#/search/1026826/ | 161F |
| This project addresses the issue of managing events and alarms by developing standard security objects for AMI systems. Creating a common definition for the structure, content, and semantics of AMI alarms and events will increase the security interoperability for AMI systems, ensure that a common set of security objects is supported, and enhance the integration of AMI systems with SIEMs and IDSs. | 2012 | 1024427 | https://www.epri.com/#/search/1024427/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report explores the possibility of using retail broadband networks for Smart Grid applications, particularly those related to residential customer integration. The report provides insight into the architecture required for future advanced metering infrastructure (AMI) systems, specifically exploring the potential of customer broadband systems and methods for determining the need to deploy private utility networks. | 2012 | 1024306 | https://www.epri.com/#/search/1024306/ | 161F |
| This report presents the results of a scoping study conducted to identify options and approaches to sub-metering of residential loads, distributed generation, and storage. The study was carried out through broad stakeholder engagement in a series of three workshops focused on metering / advanced metering infrastructure (AMI), solar photovoltaics (PV), and electric transportation. | 2012 | 1024305 | https://www.epri.com/#/search/1024305/ | 161F |
| This paper presents results from measurements of radio-frequency (RF) emissions from one specific type of smart meter. These tests were conducted as an initial step in responding to questions from the public concerning RF exposure levels from wireless smart meters. | 2011 | 1022270 | https://www.epri.com/#/search/1022270/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report presents results of an extensive laboratory assessment of the impact of DC load currents (including half-wave rectified loads) on the metrological accuracy of residential solid-state electricity meters. Sampled surveys were conducted to determine whether products producing DC currents are prevalent in residential premises. In addition, regulations and codes were studied to determine whether such products could naturally appear in the marketplace going forward. | 2011 | 1022008 | https://www.epri.com/#/search/1022008/ | 161F |
| This report describes emissions from wireless smart meters produced by two manufacturers that are currently in operation within a large service territory in the U.S. | 2011 | 1021829 | https://www.epri.com/#/search/1021829/ | 161F |
| This paper provides lessons learned from more than 30 smart metering implementations, based on the direct experiences of utility smart metering project teams. | 2010 | 1021627 | https://www.epri.com/#/search/1021627/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report documents an investigation of the characteristics of RF fields associated with Itron Smart Meters. The project was undertaken to improve understanding of public exposure to the RF emissions produced by smart meters and to respond to public concerns about potential health effects. | 2010 | 1021126 | https://www.epri.com/#/search/1021126/ | 161F |
| This paper explores a range of public perception issues related to smart meters and summarizes the actual situation for each. | 2010 | 1020908 | https://www.epri.com/#/search/1020908/ | 161F |
| This short paper focuses on questions that have arisen with regard to residential radio-frequency exposure from Automatic Meter Reading technology (or the use of so-called Smart Meters™), a component of AMI, which over time is replacing conventional electrical meters. | 2010 | 1020798 | https://www.epri.com/#/search/1020798/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report examines technologies currently being used in North America and elsewhere to implement HAN connections – narrowband and broadband wireless (IEEE 802.15.4, IEEE 802.11) and broadband powerline carrier (Homeplug AV). It analyzes some meter design and environmental factors that affect link reliability, and the features and capabilities of the underlying technologies enabling reliable communications through challenging conditions (noise and other interference). | 2010 | 1018986 | https://www.epri.com/#/search/1018986/ | 161F |
| This report identifies key cyber security requirements and suggests basic security approaches for safeguarding the many interfaces of advanced metering infrastructure (AMI) systems. These requirements, which were developed through a clearly defined security assessment procedure, are generic, but they can be used to develop more specific security requirements based on actual configurations and environments. | 2009 | 1020601 | https://www.epri.com/#/search/1020601/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report presents the findings of a study of how in-premise communication networks might be used to enable appliances to automatically identify the electric meter through which they are powered. The investigation addresses the scenario where in-premise networks overlap and multiple candidate meters exist. The ability for end-devices to determine their own power-consumption characteristics by communicating with their source meter was also studied. | 2009 | 1020318 | https://www.epri.com/#/search/1020318/ | 161F |
| This report summarizes the findings of an advanced metering infrastructure (AMI) roadmap project that was conducted for the distributors of the Tennessee Valley. These distributors, collectively represented by the Tennessee Valley Public Power Association (TVPPA), along with the Tennessee Valley Authority, are developing a long-term Smart Grid vision for the valley and believe that the diversity of AMI systems in the region can form a foundation for advanced applications. | 2009 | 1019330 | https://www.epri.com/#/search/1019330/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report is a study of how advanced metering infrastructure (AMI) systems and data can be used to benefit distribution operations and management. It includes an overview of common distribution applications and provides for each: 1) a description of how the application is commonly implemented and 2) an assessment of how AMI might be used to benefit this application. | 2009 | 1017835 | https://www.epri.com/#/search/1017835/ | 161F |
| This report provides the results of various tests performed on residential revenue meters, including tests of accuracy under reverse power conditions, accuracy in the presence of harmonics, and survivability in the presence of electrical surges. | 2009 | 1017833 | https://www.epri.com/#/search/1017833/ | 161F |
| This report describes the testing required to ensure the proper long-term functioning of an installed home area network (HAN) at utility customers' premises. | 2009 | 1016839 | https://www.epri.com/#/search/1016839/ | 161F |
| This report presents the results of accelerated life testing of solid-state domestic residential meters. | 2009 | 1016048 | https://www.epri.com/#/search/1016048/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This paper presents a review of the ANSI C12.22 standard and provides utilities with understanding of its various parts. The report includes a survey of AMI vendors to understand how it is being applied, and how / where utilities may receive value. | 2008 | 1018530 | https://www.epri.com/#/search/1018530/ | 161F |
| The AMI and Demand Response Evaluator software, Version 2.0, permits a utility to discover the possible functions of an advanced metering infrastructure (AMI) or demand response (DR) system, and to determine the benefits and requirements arising from selecting particular functions. | 2008 | 1018294 | https://www.epri.com/#/search/1018294/ | 161F |
| This report describes the use of advanced metering infrastructure (AMI) technology to minimize non-technical losses. | 2008 | 1016049 | https://www.epri.com/#/search/1016049/ | 161F |
| This report describes the use of advanced metering infrastructure (AMI) technology to minimize non-technical losses. | 2008 | 1016049 | https://www.epri.com/#/search/1016049/ | 161F |

| Description | Year | Report Number | Report Link | Source |
|---|---|---|---|---|
| This report presents the results of ongoing accelerated life testing of solid-state domestic residential meters. The project team performed reliability and accelerated life testing of meters in accordance with International Electrotechnical Commission (IEC) and American National Standards Institute (ANSI) standards. | 2007 | 1013968 | https://www.epri.com/#/search/1013968/ | 161F |
| This report provides information useful for utilities in evaluating the expected life of electronic revenue meters. | 2006 | 3002014409 | https://www.epri.com/#/search/3002014409/ | 161F |
| This report provides information useful for utilities in evaluating the expected life of electronic revenue meters. | 2006 | 1012440 | https://www.epri.com/#/search/1012440/ | 161F |

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