

VOICES of Experience

Leveraging AMI Networks and Data

March | 2019



**Advanced Grid
Research**

OFFICE OF ELECTRICITY
US DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy by National Renewable Energy Laboratory under contract No. DE-AC36-08G028308, Subtask OEPG.10294.03.01.02 in conjunction with Arara Blue Energy Group LLC under contract LAT-5-52236-01, Subtask SG10.6020.

Just the Beginning

“We are just at the tip of the iceberg of what AMI can do.”

Mark Carpenter, Senior Vice President, Transmission and Distribution Operations, Oncor Electric Delivery Company

The original business cases for implementing an advanced metering infrastructure (AMI) typically focused on the cost savings that could be achieved from avoided truck rolls and the end of manual meter reading. Now more than a decade since smart meters hit the industry, utilities are learning that the value of AMI goes far beyond logging energy usage. Advanced meters are end-point sensors that give utilities granular information about system operations and customer energy usage that allows utilities to operate more efficiently and enables a fundamental shift in how utilities interact with their customers. Engineers, data analysts, product developers, customer service representatives, and people throughout the organization are digging into the data, pairing it with other data, asking more questions, gaining insights and making data-driven decisions. AMI is allowing them to improve customer service, automate processes, protect revenue, improve power quality, verify outages, increase reliability, evaluate asset health, and more.

Yes, AMI is for billing, but if you stop at billing, you will not realize the full value that AMI provides. Understanding how utilities are leveraging their AMI networks and data to improve their operations and customer relationships—now and into the future—is the topic of this ***Voices of Experience***.

Voices of Experience is an initiative sponsored by the U.S. Department of Energy Office of Electricity’s Advanced Grid Research group (AGR) designed to bring utilities together to share their knowledge, insights and lessons learned through implementing the emerging technology that is reshaping the electric power industry. You are encouraged to download the *Voices of Experience* series from SmartGrid.gov/voices. Each guidebook is intended to stand alone, but together they build a more complete understanding of how utilities are leveraging their AMI networks and data. Past topics include:

- Smart Grid Customer Engagement
- Advanced Distribution Management Systems
- Integrating Intermittent Resources

Many of the insights developed in the previous topics are relevant to implementing and leveraging AMI. In particular, utilities embarking on AMI might find the Customer Engagement guidebook valuable when developing their communications plan, and information in the ADMS guidebook includes advice and insights that may help in overcoming the integration challenges associated with integrating AMI with legacy systems. *Voices of Experience|Integrating Intermittent Resources* provides insights into how the increased system visibility with AMI can help utilities better understand the impacts of increasing DER penetrations.

“The AMI network is similar to the iPad. We’ve installed a lot of apps, and there’s been many breakthroughs. Now, we’re exploring how we can leverage it all in our day-to-day operations and take it to the next level. New ideas are coming at us fast. We have to catch these ideas and prioritize which ones we need to do today versus which need to be done two years from now.”

Mike Putt, director of smart grid innovation for power delivery, Florida Power & Light



About this Guide

The information in this guide came directly from the people in the industry who are deploying the technology, discovering new opportunities, and wrestling with the challenges presented by AMI. What they are learning—and willing to share—helps move the whole industry towards a modern, more efficient, reliable and resilient electric grid.

Contents At a Glance

Key Insights and Takeaways 5

Exceeding Expectations 7

Operations | Unlocking the Value 9

Monitoring and Managing Operating Conditions 12

Distributed Resource Management 14

Capacity Planning 15

Model Validation 18

Asset Monitoring and Diagnosis 19

Outage Management 21

Measuring and Verification 24

Leveraging the Network 25

Customers | Forging a New Relationship 26

Providing More Information, Control, and Convenience 29

Remote Connection of Service 33

Designing Rate Programs 34

Offering Demand Response Programs 37

Customizing Solutions 39

Analytics | Making Data-Driven Decisions 41

Building Your Capabilities 43

Making the Data Accessible 45

Hosting Data In-House or in the Cloud 48

Advice For Starting Out 52

Preparing Your Organization for Change 54

About Implementation 55

About Meter Settings 56

Do I Need a Meter Data Management System? 57

About the RFP 58

More than 120 electric power professionals participated in various aspects of the **Voices of Experience|Leveraging AMI Networks and Data** (Working Group). Through a series of conference calls, one-on-one interviews and regional workshops, Working Group participants asked questions and shared their knowledge. Wherever possible, this guide preserves the voices of the participants that came through these peer-to-peer discussions. The goal of this guide is to provide information that might not be accessible elsewhere—the kind you might get from talking to a colleague at a neighboring utility.

The Working Group discussions focused on the operational value and benefits of AMI as well as the new products and services it has enabled. There also were a number of discussions specific to managing “big” data and data analytics. During the discussions, utilities often offered advice and insights on deploying AMI including decisions that will impact a utility’s ability to achieve future value from their system. That information is captured in Advice for Starting Out.

A few things to note:

- All utilities are different and have unique systems and requirements. This document is not a road map that must be followed or even vetted best practices. It is simply a compilation of examples of how utilities are using AMI networks and data to achieve value and what they are learning through their experience.
- Some of the advice and insights contained in this document are from a single source while others are summaries from group discussions. Examples and quotes from specific utilities are included with permission from the source of the information.
- The additional resources provided do not constitute an endorsement of any brand, equipment or methodology.

And finally, this guide is not a how-to manual or technical report that must be read from cover to cover. It is designed to be skimmed, thumbed through, and shared. The big headings, lists, and many callouts are intended to help readers quickly find something they can use to support their own AMI journey.

Key Insights and Takeaways

The focus of this effort is to document how utilities are leveraging their AMI networks and data to improve their operations and customer service. These six key themes emerged from the many peer-to-peer discussions and meetings:

1. AMI is an evolution.

AMI is more than an upgraded meter. While the initial business case will be built around several specific value streams, familiarity with the technology and the data (i.e., what the data it is telling you about operations) means that the value you are able to achieve will evolve over time. Even the most seasoned users of advanced metering talked about what they are learning as they become more familiar with the data and what they are planning to do with their systems in the future. So plan for the future; spend the money upfront to build a system that is flexible, scalable and capable of addressing future needs and demands.

2. AMI does more than billing and rates.

Yes, the data generated by AMI enables utilities to accurately bill their customers and design rates that can save their customers money, but it is more than a billing device. Smart meters create a network of sensors that provide visibility into how the system is operating at each endpoint. And when the data is paired with data from other systems or even external sources, it provides even more insight into how the system is operating. This is information that utilities did not have before AMI, and it has opened up opportunities for increasing operational efficiencies and improving reliability.

3. AMI is a catalyst for new customer relationships.

Customers want convenience, digital communications (i.e., text messages and internet access to data and information) and services customized to their preferences. AMI is helping to rewrite utilities' relationships with their customers by providing the information and capabilities they need to meet these expectations and keep pace with other industries. AMI enables proactive customer communications, new products tailored to the individual, and real-time communications and services that customers have become accustomed. Being able to say "we know your power is out" is just the beginning of a new relationship with your customers.

What is AMI?

U.S. Department of Energy defines an advanced metering infrastructure, also known as AMI, as an integrated system of smart meters, communications networks, and data management systems that enables automated, two-way communication between a smart meter and a utility. Utilities have described AMI as a network of sensors that provide visibility into how the system is operating at each endpoint. Smart meters record customer consumption and are capable of collecting other data such as voltage, temperature, current, etc.



4. Full-scale deployment and integration with other systems increases the value of AMI.

While each utility will have to decide the best approach for deploying their system—based on cost, priorities, and operating considerations—some value streams can only be achieved by having smart meters at all locations. In addition, integrating AMI with other systems like outage management, DERMS, or customer systems presents new opportunities for automating processes such as service orders and customer alerts. Your meter rollout may take several years depending on the size of your system, and you may have decided to start with high turnover meters as a first step, but know that full deployment of AMI unlocks its greatest value.

5. AMI enables utilities to shift their operating paradigm from reactive to proactive.

Watching and analyzing data from the meter can tell a utility if there might be an equipment problem that could lead to failure. This allows utilities to proactively plan for and address issues during normal operating hours rather than having to wait for an actual failure or customer call which might require the utility to roll a truck—sometimes in the middle of the night. This increases worker safety, reduces overtime costs, and translates into better reliability and service for customers. Proactively identifying and addressing issues rather than reacting to customer calls is a paradigm shift for utility operations.

6. AMI is worth the cost.

Even though the initial investment in AMI is significant, when utilities in the Working Group were asked if AMI was worth the cost, the resounding response was yes! And they say that knowing that it requires investments in time, equipment, and resources that often go beyond the initial cost of an AMI system. AMI upends an organization. It requires new organizational structures, processes, skillsets, and integration with legacy systems that can be challenging. Each utility must decide where AMI can provide the most value for their organization and customers and start the journey there.

Proactive outage resolution increases customer satisfaction and convenience.

Proactive outage resolution increases customer satisfaction and convenience. At SRP, 10% of outages last year [2017] were resolved where the only notification of the outage came from AMI. During one event, SRP was able to resolve an outage impacting 40 homes within one hour of being notified by the AMI. FPL reduces costs by proactively replacing equipment before it fails. Scheduled replacements reduce outage times for the company's customers by more than 93 minutes.

Exceeded Expectations

These capabilities have proven to be big wins for both customers and the utilities providing cost savings, more convenience, and improved reliability that has exceeded expectations:

Meter Ping Functionality

The meter ping functionality is when a signal is sent to the meter to determine the energized status of the meter. Utilities can use it to do on-demand reads of a single meter—in response to a customer call—to determine if an outage is a customer issue (i.e., a tripped breaker) or system issue. They can also use it to do a mass ping to all the meters or to meters in a given area. This is especially helpful in identifying smaller outages nested within larger outages so crews can verify restoration is complete before leaving an area—improving restoration efforts and decreasing customer frustration. Some utilities have incorporated the meter ping functionality into their customer applications so the customer can ping their own meter giving customers a self-service option.

Integrating AMI with OMS

In today's connected world, customers can't imagine that a utility would have to wait for a customer call in order to know that their power is out. They expect that the utility will know this and be able to tell them why the power is out and how long it will take for it to be restored. AMI's last gasp functionality

will let the utility know there is an outage; pairing that with other data from the outage management system (OMS) will help the utility determine the location of the failure so that they can send the crew to the location helping to minimize the duration of the outage. The bottom line is that utilities that have integrated AMI with their OMS say it provides BIG benefits to both the utility and their customers, and should not be overlooked.

Remote Connect/Disconnect

Utilities did not anticipate the convenience and cost savings that remote connect/disconnect switches provide. When it was first introduced, there was concern that it would be too easy to disconnect power for nonpayment with little warning—especially for at-risk populations. What the industry is finding is that this capability has been a big win for utilities...and *all* customers. Not only does it reduce truck rolls, it allows customers to be connected (or reconnected) to service within minutes rather than hours or days. Those utilities who have installed it now consider it a “must-have” feature. And while it does add cost initially, it is more than offset by cost

savings associated with reduced miles driven (fleet maintenance, fuel, crew time, worker safety, etc.). Utilities emphasize that it does need customer engagement and communications to make it successful.

Voltage Data

Smart meters are sophisticated sensors that provide information (i.e., usage, voltage, temperature, etc.) on the operational parameters of the distribution grid. Utilities were initially focused on usage data for billing and are only now understanding the value of other data that AMI can collect—especially voltage data. Voltage data is being used in many activities including validating primary circuit models, sizing transformers, identifying over or underloaded transformers, validating demand response participation, improving power quality and increasing system reliability. Experienced utilities advise that you collect as much data as you can from the start—even if you are not planning to use it.



AMI saves money, improves safety and increases customer convenience.

Reduced truck rolls are one of the immediate benefits of AMI—and not just because of remote meter reading. AMI also enables utilities to connect, reconnect and disconnect service and to “ping” the meter to test its status without dispatching a crew to the meter site. Being able to do these things remotely saves money, time and CO2 emissions as well as reducing the number of crews in the field which leads to improved safety and greater convenience for the customer (they do not have to wait for the utility to show up). Here are examples of savings reported by the Working Group.

- From March 2009 through December 2018, Oncor completed almost 31.4 million service orders remotely instead of having to dispatch personnel and vehicles to perform these tasks. This translated to:
 - 157 million miles fewer miles driven,
 - 13.1 million gallons of fuel saved and
 - 127,725 tons of CO2 not released into the environment.
- In 2015 alone, Oncor’s AMS (i.e., AMI) processed 4.5 million service orders remotely with a 98.56% success rate (meaning Oncor resolved the issue without rolling truck). This also resulted in a 96% reduction in reported injuries.
- **Ameren Illinois** reported that after implementing the remote functionality in June 2015, they have issued 800,000 electric and gas remote orders, saving nearly as many truck rolls (the number includes orders that only require a read, like move in/move out, and those requiring a switch operation, like move out without a succession). In 2018 alone, remote orders approached 430,000 orders. (Ameren Illinois decided to implement the remote functionality during the second phase of implementation, early in deployment, in order to achieve the benefit as early as possible. Deployment will conclude in 2019.)
- **Sacramento Municipal Utility District (SMUD)** reported that the remote connect/disconnect functionality in their AMI has saved hundreds of thousands of truck rolls.

Improving Safety

In addition to improving worker safety by scheduling equipment maintenance during daylight hours, utilities are able to reduce the hazards to field crews (and the public) using AMI data to identify hazards such as unregistered customer generation and downed conductors. For unauthorized interconnections, AMI data will show reverse flow to the meter or increasing voltages on the transformer that is not mapped to a known customer-owned system. Downed conductors can also be identified in part through AMI data and pose a particular public safety hazard due to the potential for severe electric shock. They also can cause outages and damage utility and customer equipment. Traditional protective equipment relays are not always reliable in detecting downed conductors in high-fault impedance environments because downed conductors might produce a lower fault current than the overcurrent relay can detect. AMI is helping utilities to detect downed conductors by using AMI voltage data coupled with complex signature analysis. In addition, utilities such as PG&E hope to use AMI data to identify faulty or failing oil filled equipment like transformers that may pose a safety risk to repair crews.

Operations | Unlocking the Value

“When you can see it visually, on a broader scale, that’s where the data starts to come alive and you’re like, ‘Wow, we should have done this years ago.’ That’s where you unlock value and it just starts being fun. You can find and fix things so much faster...it’s hugely exciting!”

Josh Snoddy, AMI/GIS/System Operations Supervisor, Holy Cross Energy.

Utilities with AMI know the meter is so much more than a device for billing. AMI gives utilities specific, measured data about the state of the distribution grid out to the grid edge, allowing operators to find—and fix—issues faster. Mining and analyzing the meter events, alarms and logs, and pairing meter data with other system data—SCADA, GIS, OMS for example—provides operational benefits that also translate into big customer benefits.

Before AMI, utilities managed, operated, and maintained a highly reliable network based on primary circuit models and analysis, but without actual data. What operators and engineers might have known intuitively through years of experience, AMI is revealing in the data. And while the data provides knowledge about the operating characteristics of the grid, visualization tools can make the data more *actionable* and therefore more valuable to the utility.

It is important to understand, however, that the value streams described in this section cannot be achieved by merely installing the network and meters; they require integration with other systems and investments in time, equipment, and resources that likely go beyond the initial cost of implementing AMI. While reports and spreadsheets are useful, the key to extracting *more* value is to get the data out of the spreadsheets (or “data jail” as one participant called it) and into tools that allow operators and engineers to visualize it and more easily act on the information.

Improving System Performance through Increased Visibility

Holy Cross Energy (HCE), a cooperative with 56,000 meters spread across Colorado’s mountainous terrain, has found value in overlaying AMI voltage data into their GIS, giving them information and insight they didn’t have before deploying their system-wide AMI. Now, HCE can visually see all of the AMI voltages along the circuit in the context of the broader, overall system. This gives them the ability to identify and correct voltage issues to improve system efficiencies or to avoid a potential failure. HCE has found low voltage regulators that are wrong or missing and identified transformers that have under and over voltage. They have even found transformers where the tap changer settings were too low (due to a circuit reconfiguration in which the previous circuit had a different operating voltage profile) because the meter voltage at one transformer was low, but was just fine and at the next transformer down the line. In another instance, HCE was able to identify and resolve an incorrect transformer setting when a capacitor on an underground line didn’t raise the line voltage as expected. AMI has given HCE visibility into their system to see and address issues they wouldn’t have known about in the past, allowing them to make the necessary setting changes for improved system performance.

ADVICE + INSIGHTS

It takes time. While some benefits of AMI are immediate, others will only be realized after you become familiar with the data and new information, and what it is telling you. The advice is to start with a limited number of value streams and then grow as you gain more knowledge and skills.

Trusting the data may require a cultural shift. Even if the crew doesn't immediately see a problem at the site, they need to keep looking. If the data is saying there is an issue, there is something there.

Customize your reports. Each utility must customize the events, alarms and reports it wants to receive, and then use the information to create business rules that signal when action must be taken.

Create applications and tools to visualize the data. Whether in your GIS or with another software program, allowing operators to see the data on a map or on another platform makes it easier to observe anomalies, identify discrepancies, and write service orders.

Don't overload the operations team with too much information. Information needs to be actionable—requiring the operator to do something—and not just information that needs to be acknowledged. You will need to find a balance so that operators have the information they need, but not so much that it becomes “noise.”

Your objectives will drive your efforts and the value you achieve. The problem you want to solve—whether it's increased reliability, process improvements, or to drive down the highest volume customer tickets—will determine the data you need to collect (e.g., are hourly reads enough or will you need 15-minute data?) and what processes have to change.

Prioritize the good ideas. Ideas for what can be done with the data may come faster than they can be implemented. Prioritize which ones to implement today and which ones need to be done two, three, or more years from now.



At a Glance: How Utilities are Using AMI Beyond Meter Reading*

Activity	Uses
Monitoring and managing operating conditions	<ul style="list-style-type: none"> Improved power quality Validation of voltage compliance Visualizing the data/Increased system visibility Volt/VAR optimization (VVO) and conservation voltage reduction (CVR) Switching analysis
Capacity planning	<ul style="list-style-type: none"> Load forecasting and projected growth Equipment investments and upgrades (e.g. distribution transformers, substation transformers, etc.) Line loss studies Circuit phase load balancing
Model validation	<ul style="list-style-type: none"> Validation of the primary circuit model GIS and network connectivity corrections Meter to transformer mapping/transformer load management (TLM) Phase identification and mapping
Distributed energy resource management	<ul style="list-style-type: none"> Identifying unregistered customer-owned systems Understanding the impacts of customer-owned systems Determining DER capacity Informing policy
Asset Monitoring and Diagnostics	<ul style="list-style-type: none"> Proactive maintenance Identifying over and underloaded transformers Identifying bad distribution voltage regulators and distribution capacitors Identifying hot sockets
Outage management	<ul style="list-style-type: none"> Verifying outages through meter pings Estimating restoration times Service order automation through remote connect/disconnect Identifying outage locations Determining cause of outage Customer communications Determine fire-caused outage using temperature data Identifying which phase of wires are down
Measuring and verification	<ul style="list-style-type: none"> Reduce/eliminate estimated reads Revenue protection Reliability metrics Demand response verification/thermostat programs Demand response and load shifting for EV charging Enables new rate options (e.g., time of use and prepay)
Identifying unsafe working conditions	<ul style="list-style-type: none"> Identifying unregistered PV installations Identifying downed live conductors

***Note:** The benefits or uses of AMI listed in this table cannot be achieved by merely installing the network and meters. Many will require integration with ADMS or other software solutions that allow the data to be analyzed, visualized and paired with other data.

Monitoring and Managing Operating Conditions

“Trust the data. The meter doesn’t lie. If you see something going on, the meter is telling you something. Dig in and see what it is. Even if the field crews can’t find anything but the data is saying there’s an issue, crews will have to keep looking; there is something there.”

Jon Pettit, AMS Program Manager, Oncor

The first utilities to install AMI were initially focused on usage data for billing and are only now understanding the value of the other data—especially voltage data—that provide additional visibility into operating conditions. The accurate voltage information along a circuit that AMI provides gives utilities data that can help them to more precisely manage distribution voltages, troubleshoot power quality issues, and evaluate switching scenarios. AMI can also be used as a system-wide voltage monitoring program to validate secondary voltage range compliance or evaluate the impact of DERs.

Prior to AMI, a customer would report an issue and the utility would dispatch a field crew to investigate. While some issues might be readily visible, others might not. The crew would likely install a voltmeter at the customer’s premises and then either sit and watch it, or leave the voltmeter for a few days before coming back to get the reading. With AMI, the utility can see voltage readings in the office without having to send the crew, reducing the time and cost of diagnosing an issue.

Utilities can also monitor voltage sags and swells as well as blink counts (a summation of the number of times a meter experiences a momentary outage) to help identify power quality issues before a customer even notices a problem. Each utility will need to determine the sag and swell settings—whether it is 5% or 7%—that works for them. When settings are too tight, the utility will be inundated with alerts, but if the settings are too broad, the utility may miss potential issues.

AMI load data is also helpful for operators when evaluating switching scenarios. Utilities can look at transformer load forecasts along with the four-hour prediction based on historical, weather-adjusted data to

evaluate what switching is necessary. Operators can then monitor AMI voltages as they perform switching schemes to verify that what the system model said would work, was actually taking place in the field. Without AMI, utilities implement switching procedures based on model results and have to wait for a customer to call to know if a problem has occurred.

Lastly, visualization tools can make the data more actionable and thus more valuable. For example, when combined with DER metering, utilities can develop more accurate estimates of advanced procurement requirements and voltage conditions. With this refined insight, utilities can reduce the size of the adequacy “buffer” applied to current procurement and reliability estimates, which can lower costs for the utility and customers. In addition, utilities are finding new and unique ways to visualize the data such as feeding it directly into ADMS, DMS or GIS for more system visibility.



Using Advanced Analytics & Data Science

Some utilities are developing algorithms and artificial intelligence (AI) programs using granular data from on-demand meter pings or shorter intervals reads to pinpoint underlying issues that might be difficult to identify even with field investigations. By applying data science to AMI, utilities are mimicking, automating, and streamlining how field crews troubleshoot system issues. Without AMI, utilities do not have the on-demand data granularity needed to build accurate models to identify outages so they must rely on customer calls before sending a crew out to investigate.

WHAT UTILITIES ARE DOING

Improving Power Quality

Building off an earlier machine learning success (iOMS – see page 22), **FPL** developed PQPing (Power Quality Ping), a tool to help resolve customer no-loss service tickets (customers experiencing power quality issues or a partial loss of power) that were referred to the company's power quality team. The tool increases the typical voltage data collection interval from once per hour to once every minute for three days. It then analyzes the high-resolution data to determine if the issue is with FPL's equipment or on the customer's end. PQPing enables FPL to resolve about 25 percent of no-loss service tickets without rolling a truck.

Increasing Visibility

SMUD created a situational awareness platform that pairs AMI data with GIS data and includes camera images at substations to give operators even more information about what could be impacting system performance.

Oncor added "bellwether" meters with more frequent read intervals (i.e., 5 minutes data pushes versus 15-minute interval reads transmitted every 4 hours) at the Dallas-Ft. Worth airport to identify and resolve issues more quickly for this customer with critical power needs.

Holy Cross Energy doesn't have full SCADA deployment so they sum up the AMI data and compare that to the SCADA data to get a better understanding of what is taking place on their distribution system.

Managing Voltage

Austin Energy will be collecting one-minute voltage data from a sample of bellwether meters (end of line, etc.) for volt/VAr optimization (VVO) as part of their ADMS upgrade. Since the ADMS will be controlling the voltage based on estimated values via closed loop VVO, they want to utilize AMI meters to give constant feedback to the ADMS. The more frequent reads will allow Austin Energy to use AMI data like SCADA telemetry so in the event the VVO application causes a condition where the voltage is outside of set tolerances, the AMI data would trigger the VVO to rerun and correct the issue.

Wake Electric Membership Cooperative (Wake EMC) is integrating AMI data with OATI's CVR program¹ for dynamic voltage control during peak usage. Wake EMC calls it Dynamic Voltage Control rather than CVR because they use it for peak shaving rather than using it 24 hours a day.

Using Visualization Tools

Central Electric Membership Cooperative (CEMC) uses a map viewer to give operators a view of meter voltage data on a map of their distribution system so operators can visually see where the issue is occurring (at what address, on what pole, etc.), making it easier to write service orders.

Austin Energy feeds AMI interval data into their ADMS system to create load profiles and to obtain better load flow estimates. By using the data, they can calculate the estimated demand on the feeder, down to each node. This information is then used to evaluate switching plans and other actions the operator can take.

"With the rapidly changing dynamic, we're fortunate to be in the position that we're in. The AMI world is a blast right now, and the opportunities are large."

Bryce Johanneck, Meter Data Management Technician,
Cass County Electric Cooperative

¹<https://www.oati.com/solution/smart-energy/conservation-voltage-reduction>

Distributed Energy Resources Management

AMI will be instrumental in understanding the impact of customer-owned resources, such as rooftop solar systems, on overall system operations. With growing penetrations of these resources, knowing system voltages at the premise-level is critical for determining when voltage violations are occurring, the cause of the violation, and what actions might be necessary to mitigate those impacts. For one utility, AMI data was used to identify a customer-owned PV system that was

causing system voltages to go outside the allowable ANSI range. The utility was able to verify this with AMI data once the customer turned off their PV system and voltage levels returned within allowable limits. AMI data is also used in hosting capacity studies as a valuable part of the load flow analysis to help utilities determine allowable DER capacity and to forecast how much DER can be added to a circuit.

WHAT UTILITIES ARE DOING

Pepco is using AMI data to proactively identify any DER that might cause a secondary voltage rise. In addition, they performed a study using 1,000 customers' AMI data to understand minimum load conditions at maximum solar output periods and how the PV generation would impact the voltage of the host other neighboring customers and the system.

SMUD calculated that up to 17% of their transformers may need to be upgraded due to increasing EV adoption.

Southern California Edison (SCE) has a pilot as part of their [Charge Ready program](#). The pilot uses AMI data to proactively shift or reduce EV charging load. SCE has tested these load management schemes using AMI meters as feedback in order to fully leverage DERs within its services territory and to maximize GHG reductions.

Informing Policy in California

In 2017, PG&E launched an effort to enable voltage monitoring across all circuits using AMI. The effort was one of the highest ranked projects from PG&E's internal SPARK Initiative, where employees crowd source new projects around specific themes. The effort proved to be fortuitous when the state's PUC began discussions about proposed changes to California's Electric Rule 21 Tariff requesting the incorporation of reactive power priority settings for smart inverters. Implementation of the new settings would take advantage of advances in smart inverter technology using the Volt/VAr and Volt/Watt function to counteract voltage deviations caused by customer-owned PV systems.

During policy discussions, there were concerns as to how the new settings, requiring the inverter to curtail power when voltages are outside acceptable voltage limits, would impact payments to consumers. PG&E analyzed six months' worth of voltage data from one million customers and assumed full curtailment (worst case) for meters that had voltages outside ANSI standards. The study found that the proposed default settings would result in about a 1% curtailment (between 1-9 hours) for the entire year for the 150,000 customers who had solar PV. It was determined that the financial impact to consumers would be minimal given avoided integration costs and the small number of hours per year the customers' systems would be curtailed. AMI voltage data proved to be a powerful tool for quantifying the impact to customers and the data-driven analysis informed policy discussions. PG&E will continue to monitor AMI voltages to verify that the analysis results hold true during actual operation.

Also through an EPIC project (EPIC 2.26), PG&E successfully demonstrated the capability that monitors, commands and controls smart inverters and the DER site controller by leveraging the existing AMI system. It also demonstrated that the 99%-coverage AMI network can be used as an additional alternative to monitor and control SCADA equipment. Policy assumptions that are not validated by actual operating data can lead to incorrect considerations. Policy assumptions that are not validated by actual operating data can lead to incorrect considerations. See Appendix B for more information about EPIC 2.26.

Capacity Planning

Without AMI, utilities use general monthly load profiles—sometimes based on a small number of research meters—to forecast future load and plan future capacity. With AMI, utilities can collect specific customer usage data throughout the month or even daily with high levels of accuracy. Actual data produces more accurate projections, and correlating this information with weather data gives utilities an even better understanding of how and where usage might be changing so they can better plan investments.

The accurate, specific nature of AMI data enables utilities to better understand usage patterns and what might be causing an issue on a circuit, or where the system might be constrained or could quickly become constrained, providing critical information for planning investments. For example, if there are ten customers for every transformer, and three customers buy a Tesla, the transformer load

has just tripled, but it will not be in any planning forecasts because customers generally do not inform the utility of an EV purchase; however, AMI would very quickly show the load change. Some utilities have developed algorithms to track service transformers that might fail due to increased usage and can even determine whether usage from a single customer (for example due to PV, bitcoin mining, or EV charging) is contributing to early equipment failure.

In addition, some utilities are looking into using AMI to calculate actual line losses by comparing AMI data to SCADA and other circuit data. This could allow them to better evaluate where and why losses are occurring. While this is not a quick or easy activity, utilities could use the information to evaluate any necessary design changes, identify inefficient equipment, and evaluate where to focus their efforts to reduce losses.

WHAT UTILITIES ARE DOING

With AMI, **Oncor** now updates distribution planning forecasts monthly. Before AMI, these forecasts were updated yearly.

SMUD's long-term strategy is to use AMI data to improve distribution planning forecasts by using segmentation and customer analytics in order to better understand forecasted load reductions based on demographics and house size.

Jacksonville Electric Authority (JEA) is using AMI data in their planning process to assess transformer sizing. Accurate load data is valuable when determining the right transformer size given cost and other considerations. Without AMI, engineers had only generalized load data that might be very different than the actual load on a given transformer.

At **Wake EMC**, when transformer upgrades are requested, the first thing the system engineer does is to look at the transformer load for the previous three weeks to determine if the transformer is hitting a threshold or not. With AMI, it is possible to evaluate whether previous transformer sizing is performing in the field as designed.

Pacific Gas & Electric's (PG&E) layered dashboard allows operators and planners to visualize voltages from the individual customer premise up to aggregated feeder level loads. Capacity planning analysts can identify the worst performing circuits and prioritize circuit upgrades that would have the biggest value (i.e., fix those issues that would cause biggest issue or that might affect the most customers first). It also gives planners the ability to determine if a temporary voltage excursion is due to circuit loading or if it is a consistent issue that needs to be resolved immediately. With the dashboard, planners and power quality engineers can determine the specific day of a voltage occurrence, and then drill down to view the voltage readings for that day to try to determine where the issue is coming from on the circuit (i.e., a specific transformer). Information in the tool is updated every three days, allowing planners and power quality engineers to verify simulations and justify forecasts.

Pepco has found that using AMI—rather than SCADA data—improves the accuracy of power flow analysis. SCADA data spreads load across the service transformers based on size, which is not what is actually occurring. Using AMI data allows Pepco to make more accurate assessments on the load of each customer and service transformer so they can make investments at the right time.

The Value of Load Shapes

“Everything is a shape!”

Jennifer Goncalves, Area Senior for Electric Distribution Capacity Planning, Pacific Gas & Electric

Like many utilities, PG&E relied on a limited number of research meters (1,000) and SCADA data (deployed at 60% of their substations) to gather the customer load information needed for distribution planning. This gave PG&E approximately 30 load shapes (hourly load profiles) to represent five million customers over 3,200 circuits. AMI provides a flexible way of aggregating load shapes for various configurations over different groupings of customers. This was not possible using the prior SCADA or the load research data and resulted in an imprecise planning process. Now with over 4 million smart meters (90% of customers) that have 99% accuracy, PG&E can create a load shape for nearly every customer and the enhanced level of granularity has allowed them to expand from 30 aggregated load shapes to some 320,000.

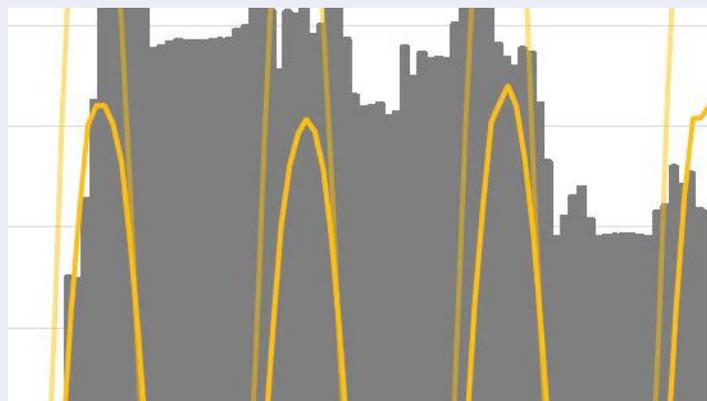
In addition to having shapes that better represent the diversity of its customer population, AMI enables more detailed and accurate shapes. Over the years, PG&E used an annual peak for planning purposes, then seasonal peaks, and most recently representative weekend and weekday shapes for each month (24 hours X 2 days X 12 months = 576 data points). PG&E now uses load shapes with 8760 data points (number of hours in a year), which is more than 15 times more data.

Without AMI data, load shapes were static; however, because load varies over time, everything is a unique shape. With a changing generation mix and new alternatives for meeting load growth, these new, specific load shapes for an exact time of day, week, or month—rather than the generalized shapes for different customer classes that used to be done by Statistical Load Research without DERs and weather such as cloudy day, rainy day, sunny day, hot day, cold day, etc. —provide important information for understanding system impacts from DERs. AMI gives PG&E the ability to produce the forecasts they need using hourly profiles for each circuit, customer class, and DER type. This gives planners a greater ability to assess needs under varying circuit configurations (i.e., load switching), the possible operational impacts of behind-

the-meter alternatives, and how customer-owned DERs will impact load growth forecasts.

PG&E generated their specific load shapes and integrated other customer-technologies and DERs into the distribution planning process under a state grant program for advanced technologies (The Electric Program Investment Charge or EPIC). The Load Shape Viewer tool developed as part of EPIC project 2.23 creates normalized load shapes and, by adding additional data like SCADA, weather and temperature data, the tool determines load sensitivity (i.e., how the shape will change if it is a cold or hot year, or in drought conditions). In other words, it generates a load shape with possibilities. The Load Shape Viewer allows a planner to quickly narrow in from the distribution planning area to the bank, to the feeder, to the customer class, to the individual customer to look at the various load shapes.

The project to develop the tools and processes—and for PG&E to transition to using AMI data as part of the utility planning process—took about five years. The catalogue of load shapes they have developed is being used to inform their latest distribution planning cycle and has allowed PG&E to more accurately capture the impact of DERs on the load growth forecasts. The analysis helped them push this load shape calculation out to the sub-circuit level, for both forecasting and operational use. As they’ve been using these new load shapes, they are finding new ways to use the data, such as for operational forecasting for planning clearances or for developing propensity models for DER adoption.



Benefits of Accurate Load Shapes to Distribution Planning

Assessing DER Impacts. Historically, distribution planners looked at peak loading when evaluating forecasts. Now, with increased numbers of customer-owned PV, minimal loading and back feeding have become important because back feeding DERs lead to damage of distribution equipment.

Understanding customer usage with TOU rates. Accurate load shapes can help utilities understand the impact time-of-use (TOU) rates have on customer bills and behavior. Without hourly usage data at the customer level, the utility does not have a reference for how customers will be impacted by and respond to the new rates. The AMI-generated load shapes can be used to inform revenue and planning forecasts with more precision.

Understanding seasonal load patterns. Specific load shapes permit planners to account for seasonal load pattern changes. Drilling down into the specific customer profile, it is possible to see, for example, exactly how a school's load changes throughout the year.

Planning for load changes due to PV adoption. Specific load shapes will tell the utility how customers are changing their energy usage behavior after installing PV systems. For example, some—but not all—customers will shift their consumption to use more of the energy they generate. This information tells the utility how much load they will still need to meet demand.

Evaluating load transfers. Using nodal load shapes (the load shape at a switch or transfer shapes) to evaluate load transfers will give a better prediction of impacts of the switch over time than if the planner were just summing up peak usages. This is because when the planner thinks about transferring some of the load to a new circuit, they're not transferring a specific load at one time only; the load transfer will occur overtime—in different amounts—making the amount of load that needs to be transferred a shape, too.

Simulating unique consumption behavior. Some customers have very unique consumption behavior that are unlike other customers in their class. For example, a school with thermal energy storage will have an extremely odd profile that peaks at 10:00 PM or midnight. Greenhouse cannabis growers will often peak on cloudy days because they typically use 1,000-watt metal halide lights for grow operations. These customers have an extreme shape that will affect the feeders, and the impact will vary depending on when the feeder peaks. Knowing loading information about these customers is useful in simulating the impact of their load on the system.

Accurately dispatching for peak load. Understanding the load profiles of customers in advance of, during, and following peak load events is critical to avoiding brownouts, or power surges. DERs, including behavioral demand response and energy storage, can complicate peak events further with their charging and snapback effects. AMI allows for more timely and granular information to help the utility power through peak events and disruptions in service.

Understanding asset utilization. With the individual load shapes, utilities can analyze and understand asset utilization that wasn't possible before AMI. For example, when a circuit is about to reach capacity, the utility can first look at whether a portion of the load can be switched to another circuit.

Evaluating circuit efficiencies. Planners can look at the entire circuit (all the way down the span level) to see impacts or inefficiencies that might be happening.

Informing transmission planning. The individual shapes at the feeder, bank, and substation level can be summed to see shapes at a higher level that can feed into transmission planning and forecasting analysis.

PG&E ADVICE: Become a shape collector! You want to know all your customer and feeder shapes.

For more details about PG&E's EPIC 2.23 project, visit https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.23.pdf

Model Validation

The primary voltage circuit model provides a representation of the utility's network from the substation to the transformer. Without AMI, the utility uses engineering analysis to translate the primary voltages into voltages on the secondary circuit (from the transformer to the home). With AMI voltage data, utilities have actual voltage measurements to validate the primary circuit models. This is important since primary circuit models and phase identification are used for a number of operations, from evaluating switching operations to conducting load flow analysis for distribution planning and design. With a validated primary circuit model that is based on measured data, models are better able to evaluate solutions to mitigate issues related to DER/PV and utilities have confidence that the changes made in the field will have the results the model predicted.

AMI is also allowing utilities to increase the accuracy of their GIS and connectivity models. Keeping these models up-to-date is difficult without AMI because changes during outage restorations and other

activities are done manually and not closely tracked (this level of granularity was traditionally not required for distribution operations). With AMI, utilities have been able to develop algorithms that can identify—and correct—errors without a truck roll. A clean GIS model is critical with increasing distribution complexity and integrated systems.

Transformer mapping is another area where utilities are using AMI data and developing algorithms to help correct errors. Accurate transformer mapping is critical for outage management communications to the customer and when evaluating DER interconnections, especially on high penetration feeders. AMI data can be used to ensure meters are correctly mapped to the transformer they are connected to; an incorrectly mapped meter will have a different voltage from the other meters on that transformer. Utilities can also use AMI data coupled with analytics to determine customer phase identification. Meter to transformer mapping, correct phase identification and mapping, and accurate GIS connectivity improve model accuracy and are crucial for capacity planning.

WHAT UTILITIES ARE DOING

JEA is leveraging their innovation lab (see page 41 for more information) to develop a detailed secondary connectivity model (SCM). The effort was motivated by their desire to maximize the useful life of transformers currently in the field, right-size new transformers, and identify transformers at risk for failures. An accurate GIS model is the cornerstone for developing advanced algorithms; every home has a mathematical relationship regarding voltage and current with the transformer and the other meters connected to the transformer. JEA will use AMI data and engineering analysis to correct topology errors—how things are connected—rather than performing an expensive manual audit of the over 80,000 distribution transformers that they must manage and maintain.

San Diego Gas & Electric (SDG&E) is investigating the use of AMI to identify which phase a meter is on and are testing algorithms for automated approaches.

A Note About Secondary Voltage Measurements

It is important to note that transitioning from calculations to precise measurements could have cost and liability implications that require careful consideration. It could mean that more violations are detected that might have been occurring before, except that the utility didn't know about it. While some require immediate attention, others might not and can be included with other planned work.

Asset Monitoring and Diagnostics

Watching and analyzing the data, pairing it with other data, and using analytics to find anomalies in the data that might otherwise be “hidden” is allowing utilities to diagnose system issues and proactively fix problems before an outage occurs or the customer notices an issue. Utilities are also able to use the data to look at recurring problems and better determine the cause. This allows utilities to proactively plan for and address issues during normal operating hours rather than having to wait for an actual failure or customer call that might require the utility to roll a truck—sometimes in the middle of the night. Increased worker safety, reduced overtime costs, plus better reliability and service for customers are some of the benefits.

Direct financial benefits of monitoring asset health using AMI:

- Reduced outage time
- Reduced overtime costs
- Maintenance during normal business hours
- Replaced before the customer was affected (no customer call)

Monitoring for significant voltage violations is one example of how utilities are identifying transformer issues. One utility gets a weekly report on voltages that are out of specification. By looking at the amplitude and high duration occurrences, it can identify a transformer issue or predict a likely failure. Another utility aggregates transformer voltage analysis data with their substation transformer load tap changer (LTC) program to predict LTC failures. Predicted failure information is then incorporated into the maintenance program.

Voltage data can also be used to identify overloaded transformers due to unexpected increases in energy use (e.g., due to abnormal system configurations or from new EV charging, bitcoin mining, etc.) or increasing load in older neighborhoods. One utility has used low voltage analysis to identify overloaded transformers due to neighborhood growth so they can evaluate any necessary circuit changes. Identifying the overloaded transformer prior to failure allows the utility the opportunity to plan that outage and even redesign the neighborhood circuit if necessary. Voltage monitoring can also be used to identify bad voltage regulators before they fail. One utility had low voltage alarms on 300 meters allowing them to proactively replace the regulator before it failed.

Utilities are also monitoring voltage sags and swells to predict faulty or bad secondary wire connections. Some are developing algorithms that include weather data because rain and lightning can cause damage to equipment that will present itself in the data.

Some utilities are looking at meter temperatures to identify and track potential issues with the meter. Querying for temperatures beyond a certain range or setting alarms when a meter is operating outside the specified thresholds will trigger an alert, allowing the utility to send a crew to evaluate the issue and replace the meter, if necessary.

FPL reported that planned transformer replacements costs can be 25 percent lower than unplanned replacements, and scheduled replacements reduce outage times by more than 93 minutes.

Identifying issues proactively moves utilities from reactive to proactive mode. As Dave Herlong of FPL put it, “Energy companies are moving quickly to proactively manage the smart grid rather than react to outages and disturbances.”



WHAT UTILITIES ARE DOING

FPL is investigating machine learning to leverage AMI data as a tool to automate system diagnostics. The idea is rather than sifting through various alerts and alarms, utilities create algorithms that allow the meter to perform analyses and send back a message when there is an issue, which then automatically generates a ticket to proactively fix it. FPL is using this concept where the logic and analysis take place at the meter. Their proactive ticket program generates a list of meters that have relayed an error message, and then generates a ticket for a field representative to examine and fix the problem.

At **Oncor**, proactive maintenance grew out of two initiatives related to improving the customer experience. Oncor knew that equipment failures hurt customer satisfaction because one, there was a failure; and two, the failure likely happens at the most inopportune time for the customer (and Oncor). Oncor asked the question, “if we improve reliability, can we gain the value add of improving the customer experience?” What they have found was that by taking a proactive approach to equipment maintenance, customers are much happier because they’re not dealing with an adverse situation. And Oncor can schedule the work at a time that’s the most appropriate for the customer and better aligned with their resources.

KCPL/Westar Energy piloted a predictive failure effort that they used to identify transformers with high risk of failure. This allowed KCPL/Westar Energy to better plan transformer replacements, reducing the number of transformer failures. This, in turn, reduced overtime costs for the company because the work could be planned during normal operating hours and outage times for customers (unplanned work has longer outage times than planned work.)

When **Pepco** saw a fuse blow under normal but extreme winter conditions, they decided to initiate a highly focused study on all fuses in the system to determine if any were close to their limit at extreme winter conditions. With their transformer load management report that uses AMI data to sum up the load on each transformer each hour of the year, Pepco can identify which transformers are overloaded, for what duration, and by how much. This allows Pepco to prioritize and schedule replacement transformers. The report is also used to identify underutilized assets and any oversized transformers which can inform designers to better size assets in the future. In addition, coupling AMI data with the solar model output, Pepco can find transformers that might see reverse power flow, that when high enough may overload in reverse. For PV analysis, the program also looks for fuses that may blow on reverse power flow and voltage regulators that need control upgrades.

PG&E also uses voltage data to identify the imminent failure of a distribution transformer by having the system scan all meter voltages and flag the abnormal voltage for dispatch and replacement of failing transformers.



Outage Management

In today's connected world, customers can't imagine that a utility would have to wait for a customer call to know that their power is out. Customers expect that the utility will know this and be able to tell them why the power is out and how long it will take to be restored.

Integrating AMI with OMS is particularly valuable in outage management efforts. AMI's last gasp functionality will let the utility know there is an outage; pairing that with other data from the outage management system (OMS) will help the utility predict the location of the failure so they can send the crew to the location, helping to minimize the outage duration. Further, meter data paired with customer contact information allows utilities to proactively communicate outage and restoration information to their customers. Some systems even allow customers to notify the utility of an outage via text message, allowing customers to confirm that their power has been restored... or is still out.

AMI also allows utilities to identify smaller outages that might be hidden (or nested) within a larger outage area. During the restoration, the utility can ping all the meters in a given area to verify that power has been restored to all premises before sending crews to another location. Without AMI, a utility might move crews before all impacted customers were restored, only knowing about the nested outage when customers called back to report it. Being able to verify that power has been completely restored to all customers before moving crews makes restoration efforts more efficient and customers happier.

The monetary benefits of leveraging AMI for outage management might be difficult to quantify in the business case because the amount of work that it will take to restore power with and without AMI will not necessarily be any different (repairing or replacing downed poles and wires doesn't change). However, AMI allows utilities to more precisely locate an outage so crews can get there quicker and restore power faster—efficiencies that are not only important to customers, but also can improve SAIDI scores, which may have a direct contribution to the bottom line.

Lessons from Large Storm Restorations

- Before a storm, identify the list of reports that are needed for various groups (i.e., critical customers; GPS locations, circuit drawings, etc.) If not, you will have to build these on the fly during the storm recovery and people might not get the data they need. Make sure reports have all the details the groups will need.
- Know what alarms/alerts you are likely to see during a storm and what they are telling you.
- Set up processes for monitoring priority meters and locating energized meters.
- During a major outage, plot GPS for all meters that are not communicating. If you see a cluster of meters out, it is likely that a transformer is out.
- AMI reports can be a great morale booster during a restoration because you can see what meters have been restored and which ones are still out. It helps crews see their progress and avoids sending crews to neighborhoods where power is already restored.
- Don't send all meter information to the OMS. Using transformer-inference (inferring a transformer is out if multiple meters on the same transformer are reporting an outage) can help limit the amount of data flowing to the OMS.
- Embed the meter ping functionality into outage processes to avoid bad truck rolls and ensure power is completely restored before moving the crew to another location.
- Think about who needs access. During a storm there might be people helping out who are unfamiliar with the information.
- You will get event logs that come back long after the event is over. These will tell a story.
- Utilities that have integrated AMI with OMS and rely on the data for their restoration efforts view AMI as a critical infrastructure. So, in addition to getting the poles and wires back up and the electricity flowing, getting the AMI network back online is also critical during a major outage. Utilities see repairing AMI network outages as a parallel activity.

A Six Sigma² Approach to Predictive Analytics

For **FPL** single customer outage tickets were more challenging and time consuming for their operators than multiple meter outages. The company had trouble identifying false outage notifications and set out on a journey to reduce single outage



notifications. With that goal in mind, FPL used a Six Sigma approach to develop analytics that would proactively identify outages that might occur at the customer premise.

The data analysis team found that 60 percent of the outage notifications were hard or unpredictable outages, a branch falling on a powerline

for example. The other 40 percent of tickets were identified as intermittent power outages that were infrequent, and when they happened, the customer may not know how to describe it. Using a text mining algorithm, the analysis team noticed they were getting a similar percentage of event messages from the meters for this type of single customer outage ticket. They realized there must be some connection between the meter “talking” to them and the intermittent outages.

FPL Insights:

- FPL only initiates proactive tickets before 7:00 pm and cancels any proactive ticket that remains after 7:00 pm, so they do not create a safety issue for crews. In addition, it’s harder to find a bad connection in the dark than it is during daylight hours.
- When embedding AMI into automated processes, make sure to have a means of reverting back to your old process. Do this in a systematic way so it automatically defaults rather than making it a manual process. Even though the stability rate of the AMI is high, it can still go down.

Data scientists started running models and evaluating the data. From that they were able to develop a mathematical equation that “told” them that when a given condition happened, there was a very high probability of a problem occurring. To validate the underlying equation and predictive model, FPL started monitoring which customers called after the algorithm flagged their account. After seeing that the algorithm was identifying issues ahead of an outage ticket, FPL began a field validation pilot. Initially, crews were skeptical when they were sent out to find an issue when a customer wasn’t experiencing a problem. The 90 percent accuracy shown in the initial pilots for proactively finding a problem—or potential problem—taught the crews to trust the data.

The effort resulted in the development of an iOMS (integrated outage management system)—a tool-based artificial intelligence ticket processing robot that eliminates non-value added truck rolls. iOMS is integrated with OMS and uses multiple data sources and machine learning to remotely investigate and resolve tickets. The tool has been tremendously successful. It runs 24/7, has a 96 percent accuracy rate, and can resolve tickets eight times faster than the previous manual process. FPL estimates that this will translate into a reduction in O&M restoration costs by a couple of million dollars each year. In fact, iOMS was able to resolve more than 3,400 tickets within the first 90 days of implementation; by the end of 2016, FPL saw a 10 percent reduction in single customer ticket volume.

²https://en.wikipedia.org/wiki/Six_Sigma

Integrating OMS with a Mix of Meters

When **Salt River Project** (SRP) first decided to implement AMI, they decided to go slowly to make sure that they did it right and the data was accurate. SRP wanted to ensure that AMI information that was being collected was accurate and not providing any false positives that would impact their operators' trust in the data.

SRP has been piloting or installing AMI meters since 2003 and now has several generations of AMI meters on their system. Using a meter farm and testing the capabilities and accuracy of each meter type, SRP selected only certain meter types to integrate with OMS that they were confident would support their business objectives. Today, 45% of SRP's smart meter population has been integrated with their OMS and this percentage will continue to grow as they replace older generation smart meters. SRP expects to have all meters integrated with their OMS by the end of 2023.

The first phase of implementation had one goal: to get the outage notifications onto a map. They didn't make any process

changes or put any rules in place; it was just to gain visibility and the operators weren't forced to do anything different at this point. SRP simply put the data in front of them and allowed them to get comfortable with it and realize its value.

The next phase incorporated status checks in the OMS so that operators didn't have to go to the head-end system to do pings or status checks.

In phase three, SRP incorporated the power-out notifications into their prediction model. By doing this, they treated power-out notifications from the meter just like a phone call from the customer. Through this phased approach, they have learned to trust meter events and now have the confidence to communicate outage information to customers before receiving additional details from impacted customers or field crews. Last year, SRP was able to communicate initial outage information to customers based on meter notifications alone for 40% of outages.

SRP ADVICE:

- **Use the meters that you have.** A good saturation of smart meters can give enough information on outages to be useful. For example, if there are ten customers on a transformer, and two or more have AMI, information from these advanced meters will tell the utility that all ten customers are out.
- **Business process changes.** While power off notifications allowed SRP to be more proactive in restoring outages, they had to think through how business process within the operations center would work. For example, would they send a crew in the middle of the night if they had received a notification, but the customer hadn't called? Working through the business processes can be challenging.
- **Filtering and clearing last gasp alerts.** A meter will send a last gasp notification if it has lost power – whether this has occurred because of an emergency or unplanned event, like a storm knocking down power lines, or planned maintenance. When integrating the AMI with OMS, SRP knew they needed to do something to ensure that dispatchers were focused on the right thing – reacting to and helping resolve emergency or unplanned outages. Therefore, SRP built robust filtering tools in their OMS to filter out the planned work for the dispatchers. In addition to filtering last gasps related to planned work, they have built in the ability to clear events if they received a notification from the meter that power was restored.



Measuring and Verification

AMI meters are constantly collecting and storing customer usage information—like a mini-computer at the grid edge. Even when the meter is not able to communicate, it is still storing data. This allows utilities to be able to retrieve the information once the communication path is restored through its gap retrieval function. With AMI, estimated reads have virtually disappeared. For one utility, the reduction of estimated meter reads has really helped increase customer satisfaction. When customers used to see an ‘E’ on their bill (indicating an estimated read), they wanted to know why they were paying when the utility didn’t actually know how much energy they had used.

Theft Detection

AMI allows utilities to detect theft much more quickly and without a field crew having to find it. Previously it might take a utility a month or two to detect theft (if they were looking for it), but now they are able to detect it in two to three days because the meter sends a last gasp notification to the utility if someone disconnects the meter. Utilities are using different methods and approaches to detect theft, and their methods must constantly evolve. (Theft detection is a little like the “Whack-a-Mole” game; as soon as a utility develops a method of detection, innovative thieves find a new way to thwart it.) Some utilities have developed their own algorithms—one has over 24—and others, like **Ameren Illinois**, are using a data analysis of load usage and service voltage to detect theft and tampering and other metering concerns. Although most utilities report loss from theft, it is generally a very small percentage compared to their total revenue; however, even a small percentage can equate to hundreds of thefts per month for a large utility.

Reliability Metrics

Utilities are also investigating what it would mean to use AMI data to calculate reliability metrics (i.e., SAIDI, SAIFI, MAIFI). Some utilities have pilots underway to better understand the implications of changing the data source for the calculations. The challenge is that changing the data sources could change the final outcome—even if the reliability hasn’t changed at all—and could give the impression that the metric was either understated or overstated in the past. For example, AMI tells utilities the specific customers who have experienced an outage and for exactly how long. In the past, utilities had to rely on OMS and field technicians to report (and remember to note) when the power was restored after they finished their work.

Using OMS, some utilities might have erred on the side of overstating outages (i.e., assuming all three phases on a line were out when it may have been only one phase) and relying on field crews to designate the time of restoration isn’t always exact. Pilot studies will help characterize the difference between the previous calculation method, which was variable, and using AMI, which is very precise, so that any changes to the overall reliability metric can be better understood. **KPCL/Westar Energy** is investigating using frequency data to report reliability metrics because frequency does not vary as much as voltage during a 15-minute interval, which means variations outside a particular range might be a better outage indicator.

Automating Meter Theft Detection

When a meter is inserted into a socket, the meter goes through a process called aggressive discovery so it can determine the optimal communication path for reporting data to the back office. During the discovery process, the meter identifies neighboring meters, fills in a routing table with all the meters next to it, and prioritizes the routes. Based on strength of closest source, the utility can determine the actual location of the meter and identify when a stolen meter is being used to supply unauthorized electricity. This provides specific information for the revenue protection department, including where the meter is located and approximately what time it was connected.

Leveraging the Network

Besides the meter, AMI includes a communications network to receive data between the meters and the utility. Utilities are beginning to explore how they can leverage the communications network that supports AMI to get even more value from the investment. For utilities

starting to implement AMI, other possible uses of the network should be considered in the decision for the communication media and transport layer to ensure it can handle future applications and capabilities.

WHAT UTILITIES ARE DOING

Communicating with smart inverters. In California, the Public Utilities Commission has approved new smart meter inverter functions requiring the capability to send and receive signals using IEEE 2030.5 communication protocols. This function allows the utility to communicate with the inverters to mitigate possible issues on the distribution system caused by customer-owned PV. California utilities are currently investigating how the AMI communications network can be leveraged to support this and what upgrades to the network might be needed. (See Appendix B: Leveraging the AMI Network to Communicate With Smart Inverters | PG&E EPIC Project 2.26)

Smart street lighting. Many utilities are exploring (and demonstrating) how to use their network for smart street lighting.

Integrating water meters. JEA is exploring whether they can leverage their AMI network to also bring back pressure sensor data from two-way advanced water meters and what additional communications requirements will be needed.

Servicing water and gas utilities. Georgia Power is in the unique position of having a radio frequency (RF) network that covers most of the state of Georgia. While the RF network was developed to support the 2.5+ million smart meters in their service territory, Georgia Power is leveraging the extensive network to offer communication services to the other gas and water utilities in the state. For the Third Party Utility (TPU) program, Georgia Power has partnered with Sensus to use Georgia Power's network to transmit meter data from third party utilities to a cloud service, where the data is stored and accessed by the third party utility.

Using voltage regulation zones. PEPSCO is evaluating a future scenario where they harness smart inverters and batteries to participate in voltage regulation. To do this, they are exploring using their AMI communications network to provide low cost secure communications to inverters that can then in turn provide Volt/VAr support. One possibility is for the future ADMS to require operating conditions for voltage regulation zones which then can use a DERMS to communicate to the inverters and other utility equipment in the zone to operate in a way that produces the desired result. Bellweather AMI sites would be monitored to insure proper voltage in the different zones of a feeder.



Customers | Forging a New Relationship

“The future of energy is being rewritten by our customers and technology.”

Arlen Orchard, Chief Executive Officer and General Manager, SMUD

The transformation in the energy industry is being driven by increasingly sophisticated customer expectations and new technologies on both sides of the meter. Customers expect the same level of information and engagement from their utility that they receive in almost all other customer transactions including consumer goods, banking, and telecommunications. They want responsive, informed customer service professionals, the ability to communicate digitally, as well as choice, transparency, personalized solutions, and information at their fingertips (think smartphones, Google, Amazon, etc.). Fortunately, AMI has created an opportunity-rich environment for utilities to meet their customers’—including small businesses—expectations and empower them with choices, data, and tools like never before.

To forge this new relationship, utilities are thinking beyond cutting operational costs and improving efficiencies. They are thinking about how the technology can benefit employees, customers, and the community, and are putting the infrastructure, processes, and people in place to achieve value. With AMI, utilities can better engage with customers not only by providing information about usage, but projecting monthly bills, alerting customers to unusual usage patterns, and sending proactive messages about outages and restoration times. All of this is translating into more convenience, less frustration, increased reliability, lower costs, and a better customer experience.

“It is easy to reduce costs at the expense of customer satisfaction; the real challenge is reducing costs while improving customer satisfaction. That’s one of the real benefits of AMI—the win isn’t just for the company, it’s also for the customer. it’s a win-win in a lot of instances.”

Juan Lopez, manager of customer service for the Florida Power & Light Company

Changing the Dynamics of the Customer Relationship

Oncor is engaging customers in restoration efforts (and changing the dynamics of the customer relationship) by asking them to send photos of downed wires. While they do their analytics internally to determine what’s going on, they also want to see what customers are seeing. Oncor has implemented a *Wire Down Program* where they reach out to customers who have called in to ask them to send a photo of the situation. This has provided unexpected customer satisfaction and value to Oncor. Now the customer is part of the restoration process as opposed to just waiting.



Meet your customers where they are today. Customers expect that easy, seamless experience from their utility, which means purchasing a smart thermostat, getting the rebate, and enrolling in the load control program with just a few clicks on their phone.

Pair AMI data with other customer data. Granular AMI data—mapped with other customer data—enables utilities to offer new solutions that provide convenience and service, and to target those products to the customers who will likely benefit from them.

Access to home energy usage information is not enough. Just a small percentage of customers who access an online account continue to look at their information on a regular basis. Proactive messaging and alerts add more value and can help drive traffic to the online portal.

Don't assume that all customers want to engage with their utility. Even if they want to see their usage data, they may not want any tips or advice from the utility.

Have a non-Wi-Fi solution. Don't forget about traditional communication channels like direct mail, grass roots efforts, and other non-Wi-Fi solutions because ~20% of customers do not go online.

Make sure your system works. If you build infrastructure to automate customer communications, it better work! If something were to happen in the field and a server fails, all of a sudden you may have a million fake outage messages going to your customers, for example. Put safeguards in place to verify information before messages are sent.

Keep in mind the customer's language is a lot different than the utility's language. If you provide details in your customer message that make sense to the utility (e.g., a breaker is out), it may not make any sense to the customer and could cause additional questions.

Call times might go up while volume goes down. When service representatives have more information available to assist customers that call the utility, the length of the call might go up because the quality of the conversation is better; i.e., more meaningful to the customer.

Provide ongoing training to your call center staff. Prepay (as well as other new rate programs) can take some time for the customer to understand, and customer service reps will get unexpected questions so make sure to do refresher training—especially if you are rolling out new programs.

Partner with vendors. Partnerships with vendor companies such as smart thermostat manufacturers allow utilities to achieve efficiency and grid reliability goals while minimizing program costs. There are many benefits to co-branding DR programs.

Getting Updated Contact Information

Getting customers to update contact information so they can receive alerts can be difficult. Several utilities ask for the information when customers call about a problem. If the problem is an outage, that is a good time to ask the customer if they want to sign up for outage alerts. Public service announcements are also being used to let customer know they can sign up for alerts from their utility. One utility said they tie contact information to credit checks and also include it on all customer communications such as billing. Many utilities try to capture the information whenever a new account is set up. Credit check companies such as Experian can use GPS coordinates to give a zip-plus-four address so that you can validate your customer data and know who actually lives at a location.

At a Glance: AMI-Enabled Customer Benefits

Fewer unplanned outages/ increased reliability	<ul style="list-style-type: none"> Proactive maintenance allows utilities to better assess asset health and plan equipment replacements. Planned replacements are quicker (so the outage is shorter) and cost less.
Faster restoration times and improved services	<ul style="list-style-type: none"> Utilities can more accurately determine the location of outages and dispatch crews more efficiently. More complete restorations. Crews can verify that the restoration is complete before moving to another area including detecting “nested” outages. Outage updates and proactive outage notifications keep the customer informed.
Improved power quality	<ul style="list-style-type: none"> Visibility into how the system is operating allows utilities to better detect voltage fluctuations that can create power quality issues.
More information and control	<ul style="list-style-type: none"> Web portals and apps can provide information to empower customers to understand their usage patterns and find opportunities to lower their energy costs. High bill alerts help customers track their energy usage and costs. Additional data for high bill research that helps customers tie behavior to costs and make changes that can lower their bill. With more information for customer service reps, utilities report high customer satisfaction and better call resolution. Fewer estimated reads increases customer confidence and trust.
Increased convenience	<ul style="list-style-type: none"> Customers do not have to call in to report an outage. Remote connection of service allows immediate service connections (and disconnections) without sending a field technician to the customer site. More self-service capabilities such as the ability to “ping” a meter during an outage restoration, view a projected bill, pay a bill, and start or stop service online. Information specific to the customer can be delivered proactively and made available to the call center for better call resolution.
Reduced fees and costs	<ul style="list-style-type: none"> Reduction or elimination of fees for reconnecting service after no-pay or for establishing new service. More rate options that align with customer behavior to decrease energy usage and lower costs. Easier access to demand response programs and products that help customers to save money.
Customer safety	<ul style="list-style-type: none"> Identifying unregistered PV installations/code violations Identifying downed live conductors Identifying heated customer panels/sockets using temperature data to help with fire prevention Determine fire-caused outages using temperature data

Providing More Information, Control and Convenience

Utilities are using data from AMI to give their customers more information, additional choices, added convenience, and more personalized service. With granular usage data, customers—both residential and commercial—can better understand and control their energy usage and costs in ways that were not previously possible.

Utilities are using AMI data to equip customer service representatives (CSRs) with more data and information to improve the quality of conversations with customers. For example, the data can help resolve billing questions because it can correlate weather or behavior changes to changes in a customer's bill. Specific load data can assist CSRs in directing customers to demand response, time-of-use, or other programs that will help customers save money. CSRs can also use AMI data to troubleshoot, and sometimes resolve, issues over the phone. If, for instance, a customer calls to say their power is out, the CSR can ping the meter to determine whether it is a customer or a utility issue. It turns out that on a "blue-sky" day, about 25% of calls regarding a power outage are on the customer side of the meter; a simple suggestion to "check your breaker" often solves the issue for the customer.

Besides enhancing customer service conversations, utilities are making AMI data directly available to their customers through online portals and messaging alerts. Portals give customers information that enables them to take a more active role in managing their costs and make better decisions. Customer portals are being used to provide energy usage (hourly, daily, etc.), to show disaggregated usage (what devices or equipment are the biggest contributors to the overall bill), to project monthly bills, and as a gateway to an online marketplace for other products and services.

Customers are using the increased information to evaluate alternative rate options to take control of their energy costs. Specific usage information, rather than the overall monthly usage data that was previously available, can also help customers evaluate and size solar

PV systems, energy storage, or other customer-owned options. For those customers who have installed a solar PV system, AMI is valuable because it can let solar customers see (at a granular level) when they are generating their own energy and when they need to rely on the utility for electricity.

Another tool that utilities—and their customers—are finding particularly convenient, are proactive customer notifications and alerts. Utilities are using these to communicate important information not only during outages, but also for routine maintenance, high bill alerts, and other situations that might affect the customer. In addition, text or email messages with targeted information suggesting an action or program encourages customers to engage on the portal and take action. Alerts have the advantage of actively pushing information to the customer rather than requiring the customer to log on to engage the customer portal.

Utilities have also started to develop mobile applications (apps). While not quite as common (yet) as web portals, some utilities see mobile apps as an "expected" customer channel today, especially for low-income customers who may be more likely to use a mobile phone than a desktop computer. Like web portals, apps allow customers to access account information (usage, projected bill, outage information, etc.). Some even enable customers to ping their own meter to see if their power is out or has been restored.

What Customers Can Do from Their Smart Phone

- Pay their bill
- Manage the energy usage
- Report and track outages
- Control their smart thermostat
- Customize alert messages about outages, billing, weather
- Ping their meter
- See bill projections



WHAT UTILITIES ARE DOING

Providing Online Portals

FPL gives customers multiple ways to understand their energy consumption. In addition to seeing their hourly or monthly consumption in either kilowatt-hours or dollars, FPL correlates consumption to the forecasted temperature, and FPL customers can go online (using the portal or the app) to get a projected bill amount. The projection will adjust throughout the month as consumption changes. If the consumption doesn't change, the final bill will be pretty close to the estimate. Before FPL rolled out this feature, they made sure the bill projection was working the way they expected to avoid unnecessary calls into the customer care center.

Direct Energy's Direct Your Energy platform has a customer suite of tools to help the customer understand and manage their usage. One of the tools uses an algorithm to disaggregate usage (Itemized Usage) so the customer can see how much of their bill went to refrigeration, air conditioning, etc. The customer can then compare their appliance usage to a peer groups' usage (Home Comparison) to see if they are spending more than they should (or want) or if their appliance is inefficient.

Sending Proactive Customer Notifications and Alerts

In addition to providing outage information, **SMUD** developed their alert system to give customers more control over their energy usage. Through the online portal, customers can select from three bill alert options: bill threshold, mid-bill alert, and high bill alert. The bill threshold alert tells customers if they are getting close to reaching the designated amount; the mid-bill alert tells customers their energy usage (bill amount) mid-way through the month so they can make adjustments early before receiving a higher than expected bill; and the high bill alert is sent if the bill is 30% higher than the same time the previous year. Since customers are not likely to look at their energy usage daily, the alerts give them the information they want so they can pay attention when needed. To date, approximately 10% of SMUD's customers have signed up for the alerts.

SRP sends notifications through e-mail, text, and automated phone calls. Last gasp notifications are used to help determine the location, size, and possible cause of an outage. Operations communicates these outage details to SRP's customer service team who then send out the first outage communications to impacted customers. Because meters have the ability to communicate outages more quickly than customers calling into the call center, SRP is able to be more proactive in sending out communications. A challenge when sending initial communications earlier is deciding how much detail to give customers. Balancing the quantity and level of information to provide to customers is something that SRP is still discussing. SRP is learning that it might be best to provide quick, but vague information at first. Then provide more detail as more information becomes available from the trouble shooter, field crews and customer calls. Once the dispatcher confirms the restoration in an area is complete, which includes using restoration notifications (RNs), the initial outage details are updated and sent to impacted customers. From the start of an outage to its end, meter notifications help SRP communicate more quickly with its customers during outage events.

"I see you are experiencing an outage"

Through the use of data analytics (and the mapping of data from multiple sources), FPL identifies a customer's account and tries anticipating the issue and reason for the customer's call. When the customer calls, the automated message might say, "I see you are experiencing an outage..." In addition, customer service representatives (CSRs) have access to the customer's energy dashboard with their data. This helps CSRs understand their energy consumption and any issues they may be experiencing.

Pinging the Meter

ComEd has integrated its mobile app with the ability for customers to ping their own meter just as a CSR would if the customer called the service center. Customers use this feature about 1,500 times per month. About 97% of the time, the meter has power and the outage is on the customer side of the meter—likely a tripped breaker or blown fuse. Consumers like the convenience and time savings the feature provides, and the utility benefits through reduced calls and truck rolls.

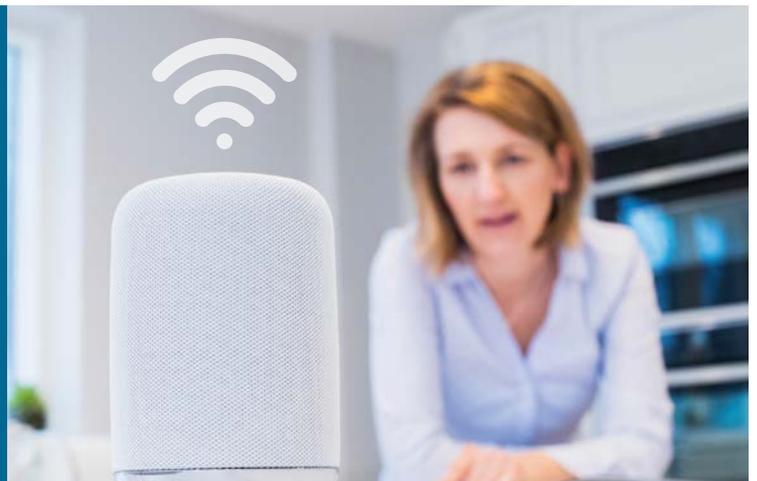
With the mass evacuations during Hurricane Irma in 2017, customers were accessing **FPL's** meter feature on the FPL mobile app to point the company had to disable it or else it would overwhelm the system. Customers were using the feature to determine if their power had been restored so they could return home. FPL is now exploring how they can present 4-hour reads as part of a smart outage map during major storms to give customers more precise information. In addition, many customers using the app during the hurricane were confused when the app would show an "X" representing no daily usage but there was still a charge. This experience demonstrated that educating customers is important – even though there is a disclaimer explaining the daily usage will not exactly match the monthly bill because of taxes, fees and other fixed charges.

Better Service for Small Business Customers

Central Maine Power, an AVANGRID operating company, has developed a web portal for small businesses so they can better manage their energy usage. AMI information in the portal provides useful information for conversations the utility's key account managers have with businesses about their electric usage. The information helps the business owners better understand the correlation between business operations and its impact on energy costs. In one instance, a chocolate factory contacted CMP because of an energy spike they were seeing in the middle of the day. The energy spike didn't make sense to them because chocolate making requires a consistent temperature. Looking at the charts and data provided by CMP, the customer realized that the spike occurred around 3:00 PM which is the time they open the delivery bay door to receive daily shipments. When the door is opened, the cool air rushes out causing the air conditioning system to kick in to bring the temperature back to their normal setting. The granular usage information was crucial to making a connection between how everyday activities were impacting energy costs.

Connected Devices and the Smart Home

The many new connected devices hitting the market are creating a huge, fast-growing industry. Several utilities have recently announced partnerships with Amazon's Alexa or Google Home to enable customers to take certain actions such as report outages and pay bills through voice commands.



My Oncor Alerts

My Oncor Alerts was launched in 2016 (see commercials on YouTube) and in 2017, Oncor sent out over 860,000 proactive messages and more than 440,000 restoration updates. Oncor estimates that the alerts have saved about 325,000 calls to their service center. A 2018 customer survey showed very positive feedback from their customers with 97% saying they would recommend My Oncor Alerts to a friend or family member.

Oncor's My Oncor Alerts is a 24/7 notification service that enables customers to receive outage restoration updates and get certain service request notifications. Customers that are enrolled in My Oncor Alerts receive messages via text, phone, or email when Oncor's systems detect an outage in their area or at their address with an estimated time of restoration (ETOR), if known. Customers also receive periodic alerts to update the estimated restoration time if it changes significantly and a notice when power has been restored. Through My Oncor Alerts, customers can report an outage via text message in addition to calling Oncor directly.

While it may sound simple, it actually requires a sophisticated IT architecture that is further complicated by integration with other systems. The challenge in developing the platform, is that it leverages data from multiple sources—meter data (real-time) combined with data from the outage management system (OMS)

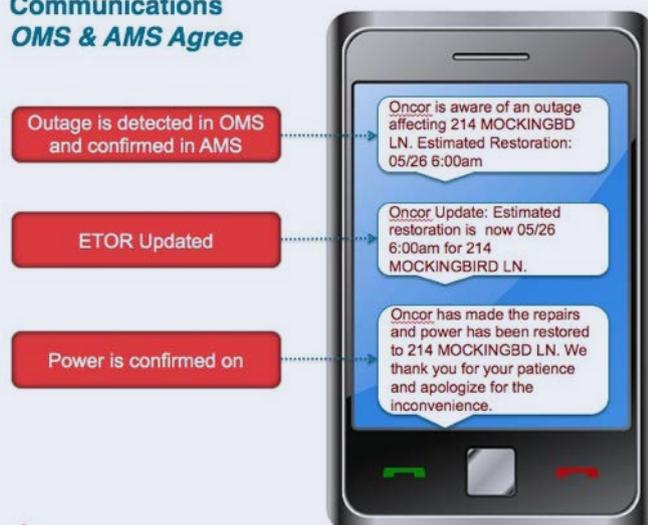
and SCADA that comes in batches— so the timing of when to send messages was a challenge. Since message accuracy is critical when communicating with customers, Oncor developed two message pathways for outage communications:

- If an outage is validated by OMS and AMI (both systems agree), Oncor send a “high confidence” advising customers that their power IS out.
- If OMS and AMI don't agree (i.e., no “last gasp” from the meter), Oncor sends a “low confidence” message, letting customers know that the power MIGHT be out (e.g., an outage has been detected in their area)

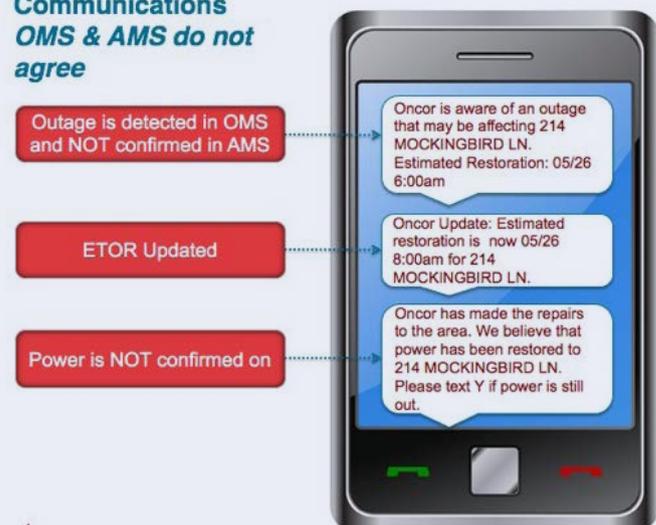
Oncor also has a similar process for restoration. They send a follow up message once they believe the power is restored asking the customer to reply back if their power is still out, saving a phone call.

Two Messaging Pathways

Communications OMS & AMS Agree



Communications OMS & AMS do not agree



Source: Oncor

Remote Connection of Service

Utilities that enable the remote connect/disconnect feature of advanced meters are finding tremendous value and realizing unexpected savings, but it does require engagement and communications to make it successful.

When the remote switch, which enables utilities to connect and disconnect power at the customer site remotely (i.e., without physically visiting the customer's premise) was first introduced, there was concern from public utility commissions and consumer advocates that too many people would have their power disconnected for nonpayment with little warning—especially at-risk populations. What the industry is finding is that the remote connect/disconnect capability has been beneficial to both utilities and customers, and utilities who have enabled it now consider it a “must have” feature.

The switch gives utilities the ability to automate functions such as move in and move out, which is especially beneficial in college towns where a utility might have 2,000 or more people leave each summer. Remote connect/disconnect has safety benefits too. When the utility avoids a truck roll, it is safer for the crew and protects the customers' privacy and property. In an emergency, power can be cut remotely to protect first responders if needed.

For customers disconnected for nonpayment, the switch is proving to be valuable as well. Before the remote switch, fees associated with reconnection after a payment could be quite burdensome and the time for reconnection lengthy (they'd have to wait for a technician to come out to the house). With AMI's remote switch, when a customer is

disconnected for nonpayment, as soon as a payment is made, the power can be restored, usually within a few minutes as opposed to waiting several days for a truck roll. Since the utility doesn't have to send out a crew to do the reconnection, the fees associated with reestablishing power can be reduced or eliminated as well.

From a collection standpoint, treatment might be different for habitual collection customers versus a one-time occurrence. For utilities with large service territories and a large number of non-paying customers, the utility can be physically limited by resources (and time) as to the number of disconnections that can be made each day. If disconnect volumes are large, there's planning that needs to take place to avoid the call center being inundated. While most customers want to pay on time, there are those that don't, even though they have the ability to do so. Some of these customers used to take advantage of the time it would take (weeks or months) due to the logistics and the number of disconnects the utility had to physically make to avoid payment. With remote connect/disconnect capabilities, customers learn the disconnect can happen quickly and are therefore more likely to pay on time or in response to a disconnection notice. One utility reported instances where customers were disconnected, payments were received, and power was restored all within seven to nine minutes.

In 2016, Oncor averaged **363,000** remote service orders a month. Of these orders, **96,500** were nonpayment disconnects and reconnects.

ADVICE + INSIGHTS

Proactive communications are needed to notify the customer of the impending disconnection. One utility makes outbound calls the same day that the disconnect notice expires, letting the customer know they will be disconnected that day. The utility also sends e-mails and other communications to try to minimize the number of actual disconnections.

Automating reconnection of service after payment has significant customer benefits. Before, when customers were disconnected, it could take up to 24 hours to get reconnected.

Remote connect/disconnect is significantly reducing call volumes for reconnections after disconnection for non-payment, and it eliminates the difficult message of, “it could take up to 24 hours” to reconnect service.

To ensure safety with automatic reconnects, one utility reported that when customers use self-serve to pay and reconnect power – either on the phone or using a digital channel – they are prompted to confirm that all appliances are turned off so power can be reconnected.

While the remote switch is an additional cost to the meter deployment, utilities that enabled it on all meters were glad they did because it turned out to be a big cost savings.

Designing Rate Programs

Granular AMI data—mapped with other customer data—enables utilities to develop new rate programs based on how their customers use energy, and then target those programs to the customers who will likely have the most interest in them or could benefit from them. Utilities can also use data to determine how new rate options might impact different customers. The data allows utilities to more accurately assess whether the program is achieving the desired results (i.e., Did the rates cause a change in the customer's behavior?).

Time-of-use rates are gaining in popularity, and for some utilities, it is the driving force behind their AMI deployment. By looking at actual customer data rather than using general customer class profiles to develop a rate, utilities can segment customers to design rates that

are tailored to their customers' usage patterns and goals. In addition, AMI data and analysis can provide powerful, data-driven insights for discussions with commissions and legislatures rather than relying on generalities and assumptions

Prepay is a payment option that is gaining interest because of the ease and control it offers customers. While prepay programs might have started with a focus on low income customers due to the fact that there are no initial deposits or credit checks required, utilities are finding interest in the program from a variety of customer segments, especially millennials.³ Utilities with prepaid billing rates report high customer satisfaction and decreased consumption.

WHAT UTILITIES ARE DOING

Direct Energy, one of the largest competitive retail energy suppliers in North America, has developed a number of offers that rely on AMI data. Their 100+ Days of Free Power is a popular time-of-use (or time-of-day) product that offers free electricity on the weekends. It is only possible with AMI interval data because granular daily interval data is necessary for billing customers for this product. These types of plans give customers a simple, strong signal to shift their electricity usage to off-peak hours when wholesale prices are lower. By changing when customers use electricity, Direct Energy can lower costs and prices.

Prepay is another popular product that **Direct Energy** offers, and the retailer's research shows that prepay customers use around 10% less energy than similar customers on a postpaid product. Direct Energy sends daily text messages to prepay customers telling them how much energy they used the previous day and the cost of that energy (i.e., how many dollars were taken out of the customer's prepay account). The idea is that real-time data combined with insights will change customer behavior. An AMI meter with a remote connect/disconnect switch is critical for the retailer's prepaid service. The meter gives Direct Energy the granular usage data they need to bill the customer daily, and enables them to quickly restore service when a payment is made.

JEA's MyWay is a billing option for customers who prefer to prepay for services in advance rather than being billed monthly—a great option for transient populations (like college students), customers who travel a lot, environmentally conscious consumers who like to keep their consumption in mind, or anyone who would rather not put down a deposit. In addition to being convenient for customers, the program helped JEA reduce stranded costs by eliminating different accounts within the same household. When customers have delinquent accounts that they are unable to pay, often they will have another member in the household (i.e., cousin, aunt and brother-in-law) sign up for a new account for electric service. With the pay-as-you-go program, 10% of the payment goes towards the past due amount for the household, giving customers a way to manage the debt while still continuing service.

When introducing time-of-use rates, **PG&E** made the personalized rate comparisons available to customers online. The comparisons were not based off of estimated or general customer class load profiles, but on each customer's actual AMI data. The customer's AMI data was run through PG&E's rate engines, and assuming the customer's energy usage would be the same the following year, the customer could see how the new rate would impact their energy costs. PG&E also uses AMI data to understand if specific rates have the intended behavioral impact to meet the goals the utility is trying to achieve.

³<http://defgllc.com/publication/the-perfect-match-between-millennials-and-prepay-energy/>

Advice from Avangrid for Developing New Rates

- A comprehensive customer engagement plan that is informed by focus groups as a part of an AMI rollout is critical.
- Plan for focus groups at the front end (even while AMI is being planned/deployed) to inform rate development. Focus groups can help make sure you're starting with the right rates and the right messaging and supporting tools.
- AMI data from a zero-phase pilot can inform different use cases and rate structures. It also can be a good way to test out how much consumers would actually save or what the impact of a new rate might be.
- Even if customers indicate they would be interested in time-of-use (TOU) rates through surveys or focus groups, that doesn't necessarily mean they will sign up for them once they are offered. You will need to have the right rates, messaging, enrollment channels and tools for them to sign up, optimize to the rate, stay on it and report satisfaction.
- Be mindful of overwhelming customers with too much information if you are trying to introduce too many solutions at the same time. If there are too many options, customers may tune out the messaging, become confused or overwhelmed.
- Consider bundling enabling technology/products with rate programs to help drive consumers to the new rate (i.e., bundling smart thermostats and DR program incentive with the rate.) Think about what the bundles should be and the specific price points needed.
- When developing rates, think about what local groups and organizations (even in different sectors) might be left behind or feel threatened by them. Look at how utility AMI goals align with the efforts from local citizen organizations, non-profits, the county, city and town objectives, and how rates can be used to support their goals. Leverage these aligned interests to promote, engage, and celebrate the ability of rates to enable multiple stakeholder interests.

Using AMI to Understand the Impact of Proposed Rates

AMI data was crucial in developing **PG&E's** Time-of-Use rates. Rather than using representative customers to develop their time-of-use rate structure, PG&E ran the numbers for every single customer based on that customer's actual data. While it required a lot of computing power, given their large number of customers, it provided tremendous value. With AMI data, PG&E could model the impacts of proposed rates in comparison to their general rate

case. This allowed PG&E to determine how the new rate structures might impact different customer classes and whether costs might be shifted from one customer class to another. PG&E then used this information to send out targeted communications to individuals or businesses detailing why the rate was changing and what it would mean for the customer.

The Benefits of Prepay

Georgia Power offers their customers a prepay program that started with a pilot project in 2012 followed by full deployment in July 2014. The program leverages the company's AMI infrastructure and utilizes remote disconnect/reconnect meters. Today, over 63,000 Georgia Power's customers are enrolled in the prepay rate plan (the program is available to all customers).

Most customers on the program make weekly payments which allow them to more easily manage their budget and monitor their energy usage. Prepay customers receive messages by text, email, or telephone about their usage and the funds balance. When customers need to make a payment, they can pay online with a debit card (no fee) or they can pay cash (fee imposed by the venue) at over 4,000 Authorized Payment Locations (APLs) around the state and thousands more nationwide. The APLs are open evenings and weekends and are convenient to where customers live, work and shop.

As part of the prepay program, there is a deferred payment plan solution for customers with an unpaid balance. When customers with an unpaid balance make a contribution to their prepay account, a portion of each dollar paid is applied to the deferred balance. This helps to reduce customer's outstanding debt while continuing electric service.

An Advocate's Perspective: Realizing the value that prepaid service can offer to customers, the Georgia Public Service Commission directed Georgia Power to work with stakeholders to develop a program. Liz Coyle of Georgia Watch emphasizes the value of stakeholders working together. She was able to influence the program design in Georgia to ensure consumer financial protections were built in.



Offering Demand Response Programs

The availability of 15-minute interval data provided by smart meters gives utilities the capability to design and offer demand response (DR) programs that are specific not only to the utility's goal of peak reductions or load shifting, but also to their customers' goals and preferences. AMI data makes it possible to predict and measure program effectiveness, focus marketing efforts on the right customers, and provide bill credits to customers based on their actual reductions during a demand response event.

Thermostat programs are gaining in popularity and have both energy efficiency and demand response benefits. To make it as seamless

as possible for their customers, some utilities are using an "instant rebate marketplace" (usually provided by a third party) that allows the customers to access the utility's demand response program at the point of purchase. By purchasing their own smart thermostat, customers can choose their preferred brand, they do not have to wait for the utility to come and install the device, and the customer has control over whether they participate, and by how much, which is critical for increasing customer participation in the programs.

BYOT Versus Utility Provided Thermostats

Two common utility thermostat programs are: 1) a bring-your-own-thermostat (BYOT) program and 2) a full-service option. Under the BYOT program, customers purchase a thermostat from an authorized supplier and install it themselves. For customers who do not want to install their own thermostat, utilities have offered a more full-service option in which the utility selects and installs the product in the customer's home.

While both programs are beneficial and give customers choices, the BYOT is more cost effective for the utility because the customer shares the cost by purchasing their own thermostat. With utility installed thermostat programs, costs are higher and there is a risk the customer won't stay in the program.

Here are some of the things the utilities shared about thermostat programs:

- Interest in smart thermostats continues to grow and the energy efficiency nature of the devices can help reduce energy usage and save customers money. In fact, Austin Energy worked to amend the local energy code so that all new homes and apartments with compatible HVAC systems are required to have smart thermostats. The increasing numbers of these devices in the field means that a utility considering a thermostat DR program will have a ready-made base of customers they can leverage to get worthwhile DR results quickly at a fairly low cost.
- If you are considering a new thermostat program, and you don't have granular enough energy usage data from AMI, talk to the vendor about getting the temperature data log back. You will still be able to gain benefits and achieve value by using the temperature data log from the vendor and partnering with an analytics company.

Connected Home

FPL is mapping the customer journey from opening an account, to getting your first bill, to your payments, as well as having an outage. Using this information, they are building a roadmap to determine the services and interactions they want to offer their customers. They currently offer more than 20 different conservation tips for customers through Alexa, but they don't yet have the capability to offer personalized tips. The company is looking to leverage connected home assistants to offer microservices such as pushing custom insights to customers.



Partnering with Third Parties

AMI data is instrumental in **Southern California Edison's (SCE)** Smart Energy thermostat program that compensates customers for the actual amount of energy reduced during each demand response event. In addition, customers receive two immediate rebates: 1) for purchasing a qualifying thermostat, and 2) for enrolling in the demand response program. To make the program easy for customers to sign up while minimizing program costs, SCE has partnered with third party thermostat vendors to market the program and to control load reductions for each called event.

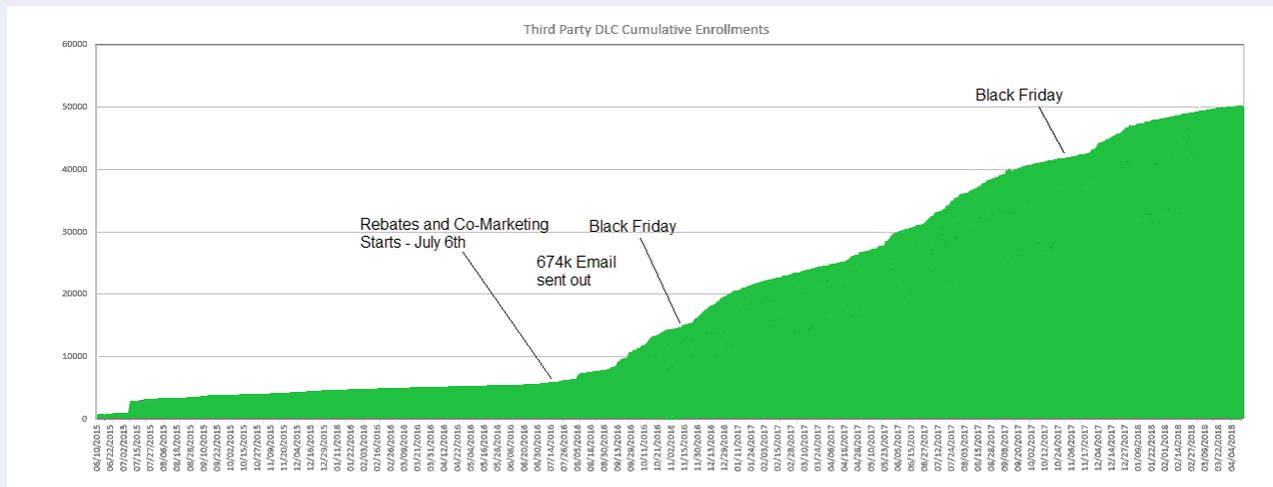
Rather than SCE communicating directly with the thermostats, each thermostat vendor controls the load for their customers (SCE promotes load drop through a performance clause in the vendor contract.). SCE requires participating vendors to use OpenADR as the communications protocol—a key element for SCE sending

event signals. SCE calls 12-14 events per year with a total load reduction of 750 watts per household. Vendor partners must have a minimum reduction of 500W per household per year. There are roughly 51,000 customers on the thermostat program for 37 MW of power controlled during an event. Each customer has control over if they participate and by how much, which is reflected on their bill.

Partnering with vendor companies to co-brand and co-market the program has significantly increased the number of customers enrolled in the program, which began in 2016. SCE pays the vendors an annual marketing fee in addition to compensation for each customer that enrolls in the program. Thermostat companies can either use the SCE program name (Smart Energy Program) or their own program name, but they must say they are working with SCE.

ADVICE FROM SCE: Don't worry about losing control of your customer. Your brand means something and has value. Partnerships allow utilities to achieve efficiency and grid reliability goals while preserving affordability.

Co-Marketing Lift



Source: Southern California Edison

Key Program Elements

- SCE co-brands and co-markets the program with their partners
- Customers compensated for each kWh reduced during each event
- Partners control load for their customers
- SCE communicates events to partners using OpenADR 2.0 cloud platform
- Reductions verified and measured using hourly AMI reads and calculated against the customer's baseline usage from the previous 5 weekdays (non-holidays; similar weather)

For more details on SCE's thermostat program visit: <https://www.sce.com/tnc/save-power-day-incentive-plus-program-terms-and-conditions>.

Customizing Solutions

Customized solutions has traditionally been something that utilities were only able to offer industrial customers with large loads. AMI data enables utilities to customize and target solutions to groups of residential and small business customers based on their energy useage, behaviors and preferences. Utilities are looking at customer load profiles and combining AMI with other data sources like census and weather data to get a better understanding of customer

preferences and to glean additional insights so they can offer customized messaging, solutions and programs. And they are beginning to segment customers based on how they use energy to offer more solutions tailored to those preferences (or usage patterns). Customized solutions not only help build stronger customer relationships, they enable utilities to market their programs and services more effectively.

WHAT UTILITIES ARE DOING

AVANGRID wants to reinforce the strong customer relationships they have already developed as well as create incremental value for customers. Using AMI usage data along with third-party research and data, AVANGRID is developing customer segmentation models based on customers' attitudes, behaviors, preferences, communication styles, and energy usage (with their load profile). This helps AVANGRID develop customized solutions that might, for example, combine a smart thermostat with a demand response program or a time-of-use rate. Segmentation will also help focus outreach efforts for energy efficiency, demand response, and TOU rates based on the AMI profiles. See *Creating an Energy Smart Community* on page 40.

PG&E collects between eight and ten billion data points a day. While they don't currently use all of the data now, they believe it will be important in the near future. One example is *Energy Efficiency Recommender*, which was developed in 2016, but uses AMI data from as far back as 2010. The tool uses an analytical approach known as collaborative filtering to develop recommendations for specific energy efficiency programs and products based on customer demographic information combined with their usage information. California has numerous energy efficient technologies and programs that customers can choose from so the tool allows PG&E to focus their marketing efforts on the best fit for each customer to maximize adoption. PG&E also uses advanced analytics that leverages AMI data to offer customers recommendations for their *Solar Choice* program. As a result of advanced analytical techniques like associative mining, PG&E was able to go from 1% to about 3% enrollment rates by targeting communications to those customers that would be most interested and then sending the information through their channel of choice.

"If customers cannot do 'self-service' on their phone, you have not designed your app right. If the customer has to call your service center, you have a very irritated customer."

William Ellis, Performance Assessment Manager,
Exelon Utilities

Agile Development Process

Commonwealth Edison's (ComEd) mobile app averages over 350,000 sessions and 500,000 transactions per month.

The mobile app was the first product ComEd developed using an Agile methodology, meaning that the app is being developed incrementally using an iterative process with constant testing and customer feedback on the design of the user interface. This process allows ComEd to keep updating and refining their app to add new user-friendly features including "slide to pay," fingerprint login, and outage reporting for customers not logged into the app.

Creating an Energy Smart Community

“The Energy Smart Community is focused on customers who are impacted the most because the customer is fundamental whether you’re building out a platform or maintaining an existing network. We want to be the trusted energy advisor to our customers, and we want to make sure this relationship is built on a seamless experience that creates value for them.” Drury MacKenzie, Smart Grid Innovation, Avangrid, Inc.

AVANGRID created what they call the Energy Smart Community which is a small-scale pilot, where they installed their first smart meters in New York—about 12,400 (80% residential)—and a distribution management system plus a number of automated line devices. AVANGRID is using the data to develop more refined forecasts for load and distributed energy resources (DERs). The goal of this mini-distribution system platform is to prove value for both the network and customers, which will then be used to inform customers about their energy usage. Their two main goals are to: 1) continue to build a strong relationship with their customers (i.e., safe and reliable power, reduce outage time, protect their information); and 2) create additional value for their customers.

AVANGRID used their available data—energy usage, market research, and behavioral data—to provide valuable solutions that are customized to their customers’ goals and values. Customers can go into the online portal and set their priorities and energy related goals. Do they want to reduce their carbon footprint? Save money? Improve their health or comfort? There are energy efficiency tips and tools within the platform and it is seamlessly connected to AVANGRID’s marketplace where customers can purchase efficiency products, get instant rebates, and enroll in demand response (DR) programs at the point of purchase. For example, a customer could

purchase a thermostat that is already programmed for the DR program. AVANGRID’s portal also connects with community solar, residential solar providers, and energy efficiency providers. Customers can download their Green Button data, or seamlessly share it securely with a solar provider they choose (or other third parties) through Green Button Connect My Data. They can even select a time-of-use rate plan to help them meet their goals. AVANGRID’s next step will be to leverage load analysis (from a vendor) to further target communications to customers to recommend energy efficiency and demand response programs, specific rates, and information on how they could shift their energy usage behavior.

For customers who do not want to go online, AVANGRID provides a seasonal print version of the customer’s energy usage with tips and suggestions for shifting their energy behavior based on disaggregation of the consumption, and related programs from which they may benefit.

AVANGRID also introduced time of use rates as part of their new offerings to the Energy Smart Community.

Analytics | Making Data-Driven Decisions

“AMI is really the start of a much broader change towards making data-driven decisions. Treat data as a valuable asset.”

JP Dolphin, Manager, Strategic Data Science Team, Pacific Gas & Electric Company

While it is possible to achieve a certain level of value by looking at meter event logs manually and evaluating the raw data, big data enabled analytics—including the tools, processes, calculations, and just plain curiosity—are needed to achieve the next level of benefits. And it has to be accessible so that many different people from across the company with different skill sets, knowledge, and interests can view it, manipulate it, pair it with other data to develop their own insights and uses for the data.

Data analytics has not historically been a core competency for utilities and those at the forefront of this evolution say that developing the skills and capabilities is a journey. Analytics can range from basic to more advanced depending on the utility’s resources and skillsets (and both provide value!). Part of the journey is just getting to know the data, what’s available, and thinking about how it could be combined with other data. As a company’s processes and skills mature, and analysts have the ability to add more data sets and experiment with

the data, it becomes possible to unlock the real value in AMI. To achieve the next level—to find hidden failures or patterns—requires new data sources (data about weather, lightning strikes, etc.), additional resources, and new skillsets.

Tackling analytics also requires breaking out of traditional roles and responsibilities and bridging the communication—or data sharing—gaps, especially between information technology and operations. For example, you likely have engineers who know the specific quirks of each meter [brand] or each region that can cause data quality issues (time synchronization or how each vendor handles daylight saving times is one example). Case in point, **PG&E** found that rather than trying to improve the end-point accuracy, it is more sustainable to record the raw meter data and then add slight tweaks—or calculations—after they brought it back. A data engineer can adjust hundreds or thousands of meters in a day versus sending a field crew out to correct 20 or 30 meters a day.

JEA’s Innovation and Data Lab

With over 417,000 customers, JEA is one of the largest community-owned electric utility companies in the United States. Located in Jacksonville, Florida, JEA is in the process of replacing their AMR meters with AMI meters, and currently has a mix that is roughly 60% AMI and 40% AMR. JEA’s Innovation and Data Lab (Lab) started when JEA decided to look at predictive analytics for distribution transformer maintenance using AMI voltage data.

The Lab is a designated area that has four circuits (10,000 meters) with a rich variety of assets that is representative of the overall service territory. The Lab allows JEA to test new technologies, build prototypes, and evaluate analytic algorithms. All the transformers in the Lab are connected to meters with full two-way AMI communications, which is critical for evaluating analytic algorithms. Designating this area within their system will allow JEA to evaluate the validity and value of algorithms, determine data collection and transmission needs, and the requirements for over-air programming.

ADVICE + INSIGHTS

Learn from others. Reaching out to other companies and even other industries can help utilities develop the analytical skillsets.

Start small and expand. Start analytics while your data set is small (early in your deployment). Focus on one area or use case and then work your way into bigger analytics projects. You don't have to begin with a big analytics program, you just need a good road map.

You don't have to develop everything in-house. Some utilities send their data to a service that analyzes and plots it. For example, there are services that can look at slowing and intermittent stops on the meters and plot it against transformer outage information so you can see trends.

Make the data available to everyone. Make sure individuals across your organization (not just the engineers) have access to the meter data. They will find different insights and value based on their role in the organization. Ensure users are aware of the data and how to access it.

Foster curiosity. Unleashing the engineers (and others in the company) to dig into the data, look at it, evaluate it, and just be curious can lead to tremendous value.

Encourage collaboration across groups. Have cross functional groups look at the data. Bring distribution operations together with customer service, marketing, and information technology, and make sure to include people without engineering backgrounds. Different groups will bring different insights. Departments working in isolation will not be able to fully leverage the power of the data. One utility has a weekly meeting where a small group of individuals from various departments do event analysis or tackle a new goal.

Give it to the new person. New engineers or others new to the organization aren't held back by historical knowledge of the system. They'll look at the data in a different way and are interested in understanding what the meter data can tell them about how the system is operating.

Pair data scientists with someone who knows the business. While data scientists will be able to find anomalies in the data that aren't readily apparent to others, they need to work alongside someone who understands the business and its nuances. Tackling analytics might require you to break out of how IT and OT traditionally operate.

Think automation. Derl Rhoades at **Alabama Power** said this about the queries: "If I have to do something twice, automate it!"

Keep senior leaders informed. Your leadership needs to understand the value of continually investing in data analysis. Consider taking an iterative development approach in order to provide value that can justify continued investment.

Look for trends and anomalies. A meter alarm doesn't always indicate what is really wrong, it just lets you know there is an issue. This is why analytics is so important. It helps identify trends and sometimes identifies trends that aren't readily apparent in the data by marrying multiple data sources.

Look outside the utility industry. When hiring data scientists, look outside the utility industry at nontraditional disciplines like biochemical or chemists or physicists—they will be able to see patterns, trends, or anomalies in the data and will be able to work with imbalanced or multi-structured data sets.

Building Your Capabilities

As you gain more sophistication in your analysis, going from descriptive to predictive and then to prescriptive analytics, the level of skill and expertise needed grows from point-and-click interfaces or software like Excel, to programming interfaces like R or Python. Becoming adept at data analytics and handling large data sets may require you to hire specialists such as data engineers and data scientists, people who

specialize in statistics and visualization, and even a query master. One utility has an employee whose job is strictly to be a service to anybody in the organization that needs data delivered to them in a specific way. But these people should not work alone; they must be paired with others in the organization who know the system and the business.

How long is the journey?

PG&E's path from descriptive to prescriptive analytics took about 8 years. PG&E installed smart meters in 2007, but just started to get into prescriptive analytics within the last one to two years (2015). However, with the citizen data scientist tools and new software available, the journey might not take that long for a utility installing AMI today—maybe two to four years to get to prescriptive analytics.



What is a data scientist?

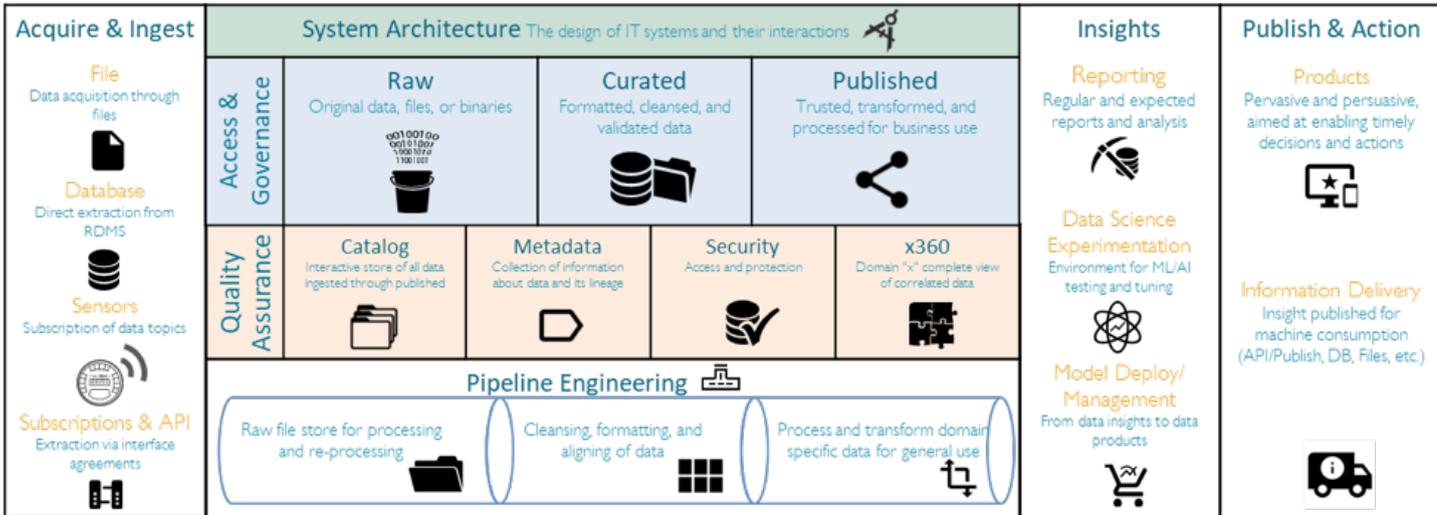
Data scientists can use analytics to find things in the data that aren't readily apparent by just looking at the data. Data scientists will be able to utilize imbalanced data sets such as where one class is overrepresented and multi-structured data sets with similar information from different sources to unearth insights and trends. For example, demographic information about customers is structured differently than the meter data about how customers use energy, which is structured differently than the voltage data. It is when you are able to combine data from multiple systems into one analysis that you realize the greatest value from the data.

Data Engineering

Data engineering might not be the most glamorous work, but it is foundational for accurate analytics as well as successful decision making and must be prioritized from the beginning. Data engineers create the

databases and set up the systems that the analysis will be run on. Data engineers sit in the technology center and usually work directly with the systems and databases rather than using tools and interfaces. The figure below illustrates the data engineering value chain and the steps that take place before analytics.

Data Engineering Value Chain



Source: JP Dolphin, PG&E

- **Ingest/Acquire.** The first step is to absorb or collect data; whether it's a file or a streaming service. The data engineering team will determine how to process the data.
- **System Architecture.** What is the plan for how IT systems interact? Should a standard database structure or vendor platform be used? Thoughtful planning, in this case called system architecture, can help make sure your IT systems are as future proof as possible.
- **Data Pipeline.** The data pipeline takes the raw data and puts it in a format that's accessible and in a location where it can be stored efficiently.
- **Data Quality.** This step includes cataloging the data and the metadata, which is information about the data. For example, what meter did this read come from? How accurate do we think it is? Synchronizing the timestamps of different data sets, such as SCADA data and AMI, is another important step for analytics.
- **Data Access and Governance.** Understanding who has access to what data is not only important for cybersecurity concerns, but also for determining who has read access versus who has write access, and who is responsible for improving data quality or creating calculated fields.
- **Data Lab or Data Lake.** This is the environment where analysts and data scientists can play with and manipulate the data. Without this space, they will be doing things on their own local machine

(the opposite of a best practice) because it doesn't allow the analysis to be scaled or shared across teams.

- **Tools and Databases.** The last step in the chain is the development of any systems, tools, or databases—or maybe a dashboard—for sharing and publishing the data.

Work Backwards to Connect the Dots

You can never connect the dots forward—only backwards—and analytics helps make this possible. Many of the use cases (or algorithms) that have been developed started with a specific use case or initiative within the company—a reliability initiative or an initiative to drive down the highest volume customer tickets, for example. FPL found that 50 percent of restoration costs were attributed to sending a resource to investigate the cause of the outage. To reduce this cost, FPL used analytics to determine the cause of these outages by looking at the data (and then developed an algorithm to identify and predict outages before they occurred.

Making the Data Accessible

Moving from traditional meters to AMI significantly increases the amount of data utilities collect, store, and manage. Monthly reads create 12 data points annually. Transitioning to hourly reads creates 8,760 data points – that’s a 730-fold increase. Shortening read intervals further to 15-minute intervals creates 35,040 data points—per customer each year! This creates what one participant categorized as a “tsunami of data.”

Making the data easily accessible to all business units across the organization is a good place to start. Unfortunately, collecting, storing, and managing big data (not just from AMI, but other sources, too) is new, uncharted territory for most utilities. Decisions will need to be made based on the organization’s unique situation; i.e., resources, existing systems, skills, regulations, etc. You may decide to store the data in the headend or use a meter data management system (MDMS), purchase a system or develop your own, create a data sandbox or something else, invest in your own servers, or use the cloud. There is no one solution for everyone; each utility will need to determine their best approach for managing and accessing the data. And, there are always tradeoffs. Data engineers and analysts will want more data, but the additional costs (e.g., from beefing up your backhaul and ensuring cybersecurity) must be balanced with the benefits of bringing back additional data. Or the ease of using a cloud-based solution must be considered and weighed against a possible increase in cybersecurity risks or perceived privacy issues.

“I’ve got people from distribution operations that are doing analytical studies. Our measurement services and customer experience groups are doing studies as well. I’m just enabling analytics by making the data accessible to them.”

Donny Helm, Director of Technology Strategy and Architecture, Oncor

The Meter Data Tsunami

Monthly reads create **12** data points annually. Transitioning to hourly reads creates to **8,760** data points – that’s a 730-fold increase. Shortening read intervals further to 15-minute intervals creates **35,040** data points—per customer each year!



You don't have to start big. Start small with a few use cases. Create a good roadmap by identifying specific area where you may get some great value very quickly, and then work your way into a bigger program.

Establish data governance. Data governance provides rules and guidelines about how the data can be accessed and restrictions on who has read versus write access. Strong data governance will save time and money over the long term by reducing demands on your IT staff and protecting the integrity of your data and systems. **Alabama Power's** data governance team produced a user's guide for **Southern Company** explaining the rules around accessing data that they provide to anyone who requests access to the data.

Focus on getting quality data from the start. It is important and easier to ensure data quality from the onset rather than going back and trying to reinvent that once programs and systems are in place. Invest the time to clean up your data and develop the processes to maintain quality from the start; it will NOT get easier over time.

Assign ownership to the data. AMI is a solution that cuts across the entire business. Everyone in the company will want to use the data and has a stake in it, but you must identify an individual or group with responsibility for maintaining the data quality and availability for the organization.

Keep historical data. You will have to decide how much data you want to keep and for how long, but as you start analyzing the data and using it to understand your system better, you will want to have historical data available to fill in the gaps or help with investigations.

Create common tables and queries. Generating common tables and queries so everyone is not recreating the information saves time.

Don't put the data in the tools. Build an agnostic data layer that can be used with any kind of analytical tools, including Excel. If you put it in a tool, and someone else wants to use that same data, but not the same tool, you have to either redefine it, repurpose it, or try to integrate it with the tool to move forward. Keep your data agnostic to the tools or the applications.

Use your vendors. Identify the source applications to be evaluated and make sure the data quality is good, then reach out to the vendors to get their entity relationship diagrams. These will lay out what tables or data is being maintained within the system. If the vendor doesn't have that, you can typically find those key tables through the application itself. Once that's done, start with an evaluation you do once a week (you don't have to start with a replication), then define a common method for extracting data out of those transactional systems and putting them in a very small database. This might even be an Excel spreadsheet if the data is small enough. Wherever you put it, make that the data repository.

Create a disaster recovery plan. Design and implement disaster recovery architecture and infrastructure early in your project. Develop disaster recovery procedures so that in the event of an AMI backend failure, you will be prepared to continue with normal operations. Make sure to exercise the plan periodically to ensure it is fully functional and employees understand the procedures so it can be implemented efficiently in the event of an actual failure.

Building a Data Sandbox

Oncor understood early on in their AMI deployment that giving employees across the enterprise access to the data would be fundamental in supporting efforts to drive process improvements. This led Oncor to develop a “data sandbox” as part of a broader data initiative.

The data sandbox stores a copy of the utility’s data from multiple systems creating a “discovery zone” where development and experimental work can be done rather than against the transactional data store. It also includes a historical data store. Oncor uses a replication layer so the data is expressed exactly as it exists in the application rather than doing data transformation. The sandbox eliminates the difficulties and inefficiencies of individuals copying and moving the data.

A single team of four people is responsible for the overall security and governance of the data and serves as the bridge between OT and IT, supporting subject matter experts throughout the organization. The team provides help in querying and understanding the data and how to access it as well as defining or identifying value for operations. In addition, Oncor has five doctorate-level data scientists on staff and holds weekly analytics meetings so people across business units can share what they are doing.

Individual schemas are a key element of the discovery zone. Data from the production database is copied and dropped into the individual’s schema, so it can be manipulated or changed to support the development of analytical algorithms. Once the owner has a solution they want to productionalize, it’s taken out of their schema, reviewed, and then deployed in the core discovery zone schema so that it can leverage all the information in that database. Individual schemas (limited to one gigabyte each) allow the owner to do more than might typically be allowed by an IT shop.

Oncor’s data store was built internally and brings together data from multiple systems. It is the mechanism for giving access to users. Over the past three years, Oncor spent around \$1 million dollars for this effort, but those costs have already been recovered through avoided people time, resource time, study times, failure analysis times, and more.

See Appendix C for more information on Oncor’s Data Analytics Platform.

Development Criteria for Oncor’s Data Sandbox

Self-service. Data easily accessible with minimum IT support.

Access to multiple data sets. Provide the ability to combine different data sets to find new insights.

Easily understandable and digestible data. No need to learn a new application to use the data.

Minimize amount of data to be maintained. Allows applications to be switched quickly during a failover or disaster recovery situation.

Segmented and controlled access. Queries won’t affect day-to-day operations.

Centralized governance, but decentralized access. Allow business groups to perform their own studies without the need for a formal IT project.

Hosting Data In-house or in the Cloud?

Where to keep (or host) the meter data—on a server located at the utility or on remote servers hosted on the internet, aka the cloud—is a decision each utility will need to make at some point in their AMI journey. Cloud computing has many benefits, especially for advanced

data analytics (with the computing power it requires), but some utilities have expressed concerns with cybersecurity, customer data privacy, and ease of data access. Here are some things to consider when making this decision:

- **Staffing.** Does your staff have the capacity and skills to manage the data internally? For small utilities, using a hosted service can help overcome IT staffing hurdles and lift the burden on the internal IT department.
- **Space.** Do you have the physical space to house the systems you will need? For some utilities, space for data centers could be limited.
- **Speed.** Will cloud computing help speed implementation? Can a vendor roll out enhancements or fix bugs faster than you might be able to do internally?
- **Access.** Will a hosted solution support the access you need? One concern is that direct access to data would be less with a hosted solution than if the utility hosted the data internally, and there may be charges and fees associated with additional access.
- **Data integrity.** Do you have the systems in place to make sure that the data you receive is the right data and that it has been validated?
- **Cost.** Cost considerations can drive the decision. However, new rules around cost recovery for cloud services might change internal

discussions. (For more information on capitalizing software as a Service (SaaS), go to FASB.org.

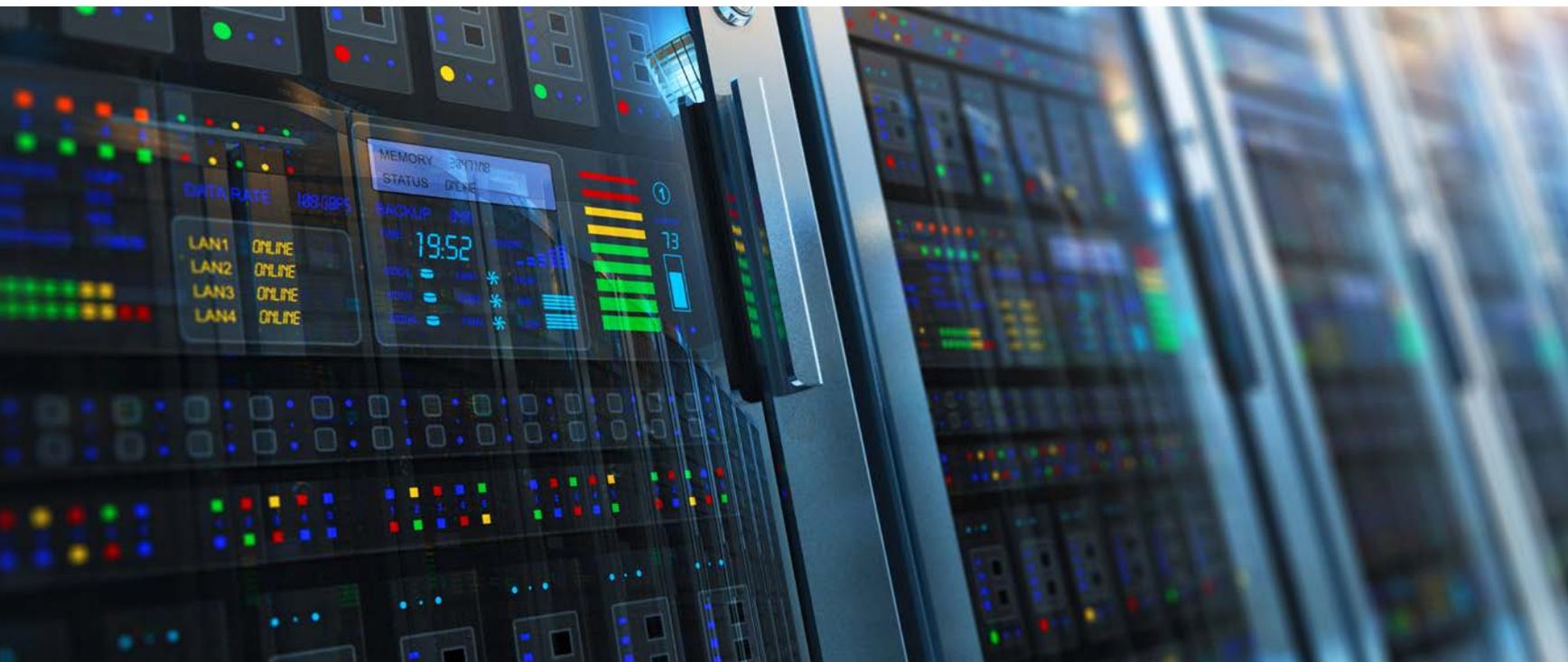
- **Disaster Recovery.** How does your cloud and internet service provider's reliability compare to your internal IT systems? What protections are in place to ensure this reliability is maintained during an emergency?

Cloud or Hosted Considerations

	Core	Non-Core
Mission-Critical	Private cloud or non-cloud (e.g. Transmission SCADA)	Good cloud application (e.g. AVI, mobile workforce)
Non Mission-Critical	Potential Cloud Application (e.g. AMI)	Good cloud application (e.g. HR, Employee Services)

Technology Pilot Projects

Source: Dan Bowman, Manager of Engineering, Wake EMC



Success with the Cloud

In 2012 **Wake EMC** in North Carolina started their AMI implementation with a 90-day pilot. Due to the infrastructure costs of hosting data internally, Wake EMC decided to have their software hosted during the pilot. The pilot allowed them to get familiar with where the data was going and how the system worked. It worked flawlessly, and because it worked so well during the pilot, Wake EMC decided to continue with a cloud-based hosted solution when they rolled out AMI to the entire service territory.

Wake EMC found that the hosting company had the necessary expertise to keep the system up and running, as well as for applying the necessary patches. While Wake EMC admits they don't have direct access to the database like they would if they hosted it internally, they are pleased with the reports and analysis their contractor provides. Outsourcing also has the benefit of freeing up resources and taking the burden off their internal IT department.

In addition to hosting their AMI data, Wake EMC also uses a service to host their meter data management system (MDMS), auto vehicle locator, and dynamic voltage control. Even their analytics package is not on an internal server. Wake EMC connects through the cloud to their different internal systems (CIS, OMS, GIS, etc.) and performs their analytics using a web tool. Wake EMC's dynamic voltage control platform can actually send commands directly to their voltage regulators in order to change their voltage settings. By getting AMI voltage data directly from the hosted software, Wake EMC can make predictions and forecast what conservation voltage reduction (CVR) might be available. (MultiSpeak has been critical for the integration.) While these systems are all hosted in different locations, Wake EMC doesn't see this as a barrier. They know exactly where their data is—it's not on a network at some unknown location—and it is on a private cloud that requires authentication for access.

Wake EMC wants to be quick and nimble to take advantage of new solutions and the value they offer. Using a hosted solution has allowed them to do just that. The cooperative has less than 50 employees supporting an operation that has over 45,000 meters, and even with many employee retirements, Wake EMC has been able to continue to work with the existing IT resources while implementing new solutions.

Wake EMC's hosted solutions have been extremely reliable and have allowed restoration teams to access their systems remotely when Wake EMC lost connectivity at its headquarters location during Hurricane Matthew, giving them system visibility that they wouldn't have had otherwise.

Insight from Wake EMC: Don't be afraid to put in a system with a high reward possibility. Wake EMC does this by testing the new technology using a hosted solution whenever possible to limit the burden on internal resources. Make sure to have an exit strategy in case it is not working as anticipated.

Multispeak

Multispeak is a specification that defines standardized interfaces among enterprise software applications commonly used by electric utilities. The current Specification is mature in its coverage of 40 functional endpoints including meter reading, connect/disconnect, meter data management, outage detection, load management, SCADA, demand response, and distribution automation control – many of the critical aspects of smart grid operation. For more information, go to www.multispeak.org.

The Importance of Disaster Recovery for Data

Ameren Illinois realized early on in their AMI planning that a disaster recovery plan would be critical as they moved away from the traditional meter reading functionality and business units began to rely on the visibility and information from AMI (such as meter outages, alarms, flags, events, remote orders, voltage optimization, etc.). To plan for an AMI backend failure, the company developed a plan that does not require disaster recovery infrastructure to cannibalize other non-production infrastructure resources. It is sized for full scale operation, is located in a separate data center, and includes data replication. The disaster recovery infrastructure allows for daily, full volume production capabilities of the AMI application and business processes to run for extended lengths of time without issue.

At Ameren Illinois, the AMI disaster recovery procedures are exercised at least twice per year to ensure it is fully functional. Exercising the functionality at this frequency not only helps to ensure employees understand the procedures but that they are prepared to implement the plan in the event of an actual failure. During a data recover exercise, employees execute a defined series of steps outlined in the disaster recovery playbook, which detail how to perform a complete failover to the disaster recovery infrastructure. Once the solution is on the disaster recovery infrastructure it will operate there for at least a week before returning to the AMI production infrastructure.

Insight from Ameren Illinois: Having a solid disaster recovery solution that employees are familiar with and have practiced implementing ensures a minimal disruption of AMI capabilities and business processes in the event of a significant issue occurring in the production data center.



Analytics for Small Utilities

Angela Hare, Vice President of Customer Service and Information Technology at **Central Electric Membership Coop (CEMC)**, a co-op located in North Carolina that has around 23,000 meters, had heard all the reasons why they should not do analytics:

- **We are too small.**
- **It will cost too much.**
- **We know our system.**
- **We will just fix it when it breaks.**

However, after weighing the cost versus the benefits, CEMC decided to leverage their data—not just the interval reads, but also the meter alarms, alerts, and logs and to use the meter vendor’s analytics program. Here are some of the things their AMI data enabled:

- **Uncovering meter tampering,**
- **Identifying unregistered DER interconnections,**
- **Better understanding of transformer failures (i.e., one caused by increased usage from bitcoin mining), and**
- **Proactively identifying customer issues.**

One analysis that CEMC finds particularly valuable is the blink count, which identifies momentary outages that are not of long enough duration to show up in the outage management system, but might indicate an issue that needs the utility’s attention. CEMC has also identified connectivity errors and found overloaded and underloaded transformers using the vendor’s analytics program.

ADVICE FROM CEMC:

While sophisticated analytics that require a team of engineers and data scientists is valuable, analytics can be done by small utilities and doesn’t have to cost a lot of money.



Recommended Resources for Data Analytics

- Booz Allen Hamilton, The Field Guide to Data Science: <https://www.boozallen.com/s/insight/publication/field-guide-to-data-science.html>
- Cognitive Class.ai – Video classes for business leaders to understand the challenges and value analytics can provide
- Coursera or Data Camp – Video classes for individual contributors, analysts, and engineers who want to learn more and improve their skill
- Gartner Research – Whitepapers on trends and vendor capabilities
- MIT Business Intelligence Analyst job description provides a good job description for a data engineer and explains the skills, experience, and tools necessary to do the job well.

Advice for Starting Out

“Three rules for implementing AMI: Don’t break billing, don’t break billing, don’t break billing. Because at the end of the day, the primary function of AMI is obtaining meter readings that support the meter-to-cash process.” David Kuhlmann, Digital Manager – Meter Technologies, Ameren Services Corporation

Transitioning to AMI is considered by many utilities to be the foundation for achieving their smart grid goals. Utilities slowly began deploying smart meters around 2007 but saw a rapid increase with the help of the American Recovery and Reinvestment Act of 2009, which supported the deployment of more than 16 million smart meters. By the end of 2016, the number of smart meters deployed in the U.S. hit 70 million, and the number is projected to reach 90 million by 2020. What this means is that there is a lot of knowledge—about the challenges, as well as the value, of AMI—that can be shared. There are also many things that fall under the category of “what I wish I had known” that are included here to help those utilities just starting out.



The Value of a Small-Scale or Phased Approach

Consider a small-scale pilot or a phased approach to implementation. Not to determine if you want to do the project, but to identify issues you might have missed. While conducting a pilot can be costly, it might save you money in the long run. It can help you think through processes and verify assumptions before a large-scale rollout. Here are a few things that you can learn through a phase 0 “pilot”:

- How to interface with the various vendors on the project
- What work to keep in-house and what to outsource
- Determining alert settings and how to manage meter events
- Which processes can be automated
- What processes will be impacted and how they need to change
- Becoming familiar with the data coming in and building workforce trust in the data
- How to manage the large number of meters that have to be changed out and tested. (A large scale roll out isn’t the same as a typical meter change out—one utility reported changing out 3,000+ meters per day.)

Lastly, make sure the pilot is scalable!

⁴ <https://www.eia.gov/todayinenergy/detail.php?id=34012>

⁵ Electric Company Smart Meter Deployments: Foundation for A Smart Grid, Institute for Electric Innovation, October 2016

Identify your core goals. Understand your organization's goals and define your use cases from the beginning – before you design your system. However, knowing what you want today is not enough; you will want to think through future scenarios and identify the functionality and capabilities, and data you want. This will help you design a system that is flexible, scalable and capable of addressing future needs.

Think beyond your initial plans. Consider the role of AMI in achieving the utility's long-term vision. While cost may limit what you can implement, think through future scenarios and how that might impact design criteria. All functionalities should be considered, and utilities should research potential uses/possibilities before rejecting concepts.

Build a cross-functional team. Include people who understand the strategy and have bought into the vision. Do not have the meter shop plan the deployment on their own; engage engineering from the start and be looking at functional uses for operations.

Talk to other utilities. Take advantage of those who went before you. Find out what they are doing and ask what worked with their system and what didn't.

Choose the right communications technology. AMI is not just about the meters. The communications platform is the cornerstone that all applications—like meter reading—depend on. Consider how much data you will bring back—not only initially, but in the future—and the terrain of your service territory so you can build flexibility into your system.

Make cybersecurity a priority. Cybersecurity should be built into your system. One utility has a document with 250 pages of cybersecurity protocols!

Enlist outside help. Other utilities, meter vendors, and consulting firms are all resources that can provide materials, advice, and expertise not only for your AMI deployment, but also how to use or develop analytical tools.

Commit to the technology Realize the system will need maintenance and continual upgrades so plan for it upfront. "It's the nature of the beast," said one workshop participant.

Ask vendors very specific questions. For example, the prepaid vendor might be Multispeak compliant but that doesn't mean it will integrate with your system unless they are using the same version of Multispeak as you are.



Prepare Your Organization for Change

Implementing AMI will touch nearly every business unit at a utility. And while that is one of the many benefits of AMI, it can also upend your entire organization. AMI will challenge your organization's culture too, by requiring people to change not only how they do things, but

also how they think of things. While changing a culture is difficult, once employees see the value of AMI, it "becomes contagious!" So be prepared to manage a changing organization.

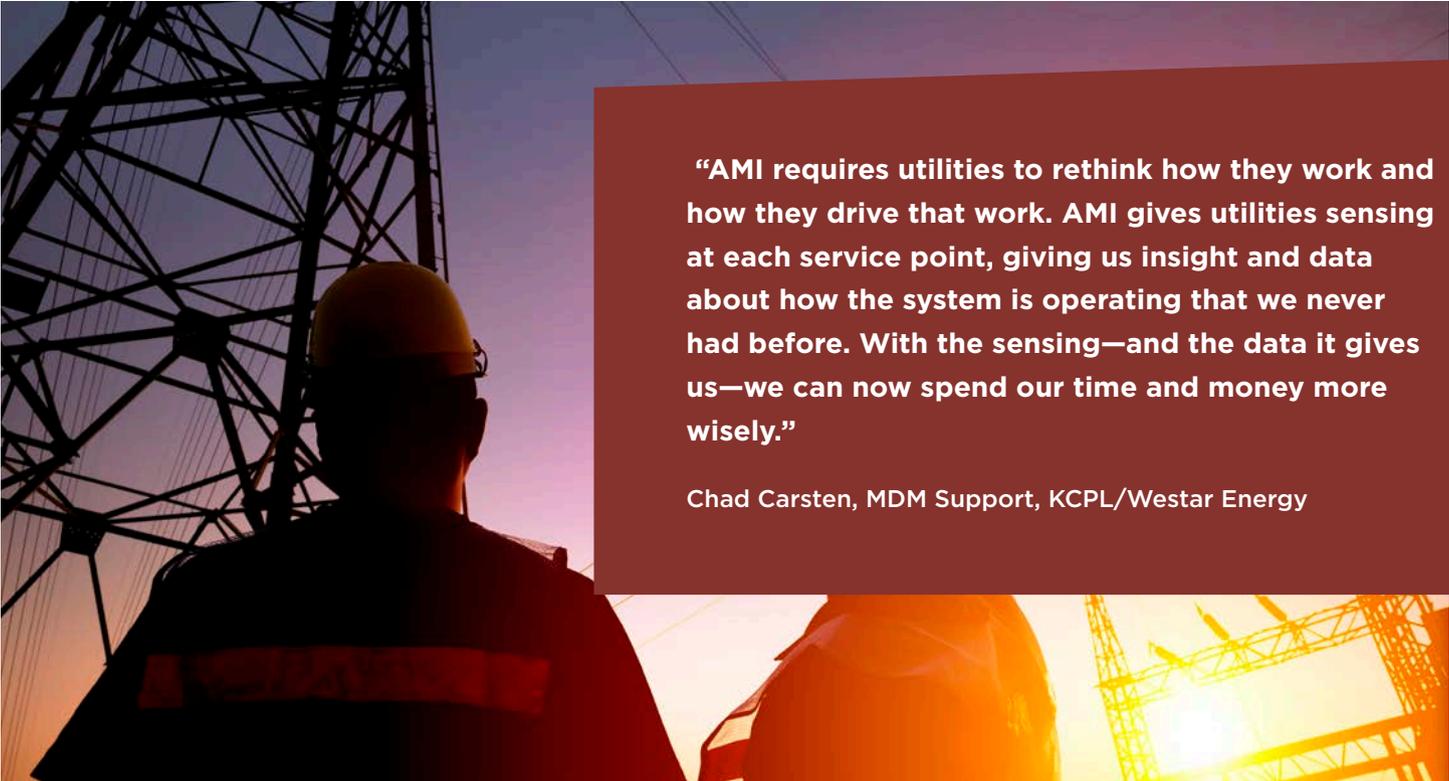
ADVICE + INSIGHTS

Evaluate your processes. Every business process from meter to build will change. You will need to define and document business processes and identify the gaps. Determine which processes will be automated or eliminated and—most importantly—how each can be improved. A full AMI deployment can take several years and during that time, you will need to manage three processes simultaneously: the old, the new, and the transition.

Invest in change management. AMI will upend the organization. Employees will need training on the new processes and technology and how it will impact their jobs and the organization's culture.

You will need to re-train field crews to trust data. In the past, field crews could check to see if the lights are on. Now that's not enough. If they don't initially find something, they need keep looking because the meter is telling you there is an issue; crews just have to find it. Trust is built on the experience—seeing over and over again that the data was right.

Consider a Six Sigma methodology or agile software development approach. These approaches to software and product development are designed to increase collaboration and encourage a rapid and flexible response to change.



“AMI requires utilities to rethink how they work and how they drive that work. AMI gives utilities sensing at each service point, giving us insight and data about how the system is operating that we never had before. With the sensing—and the data it gives us—we can now spend our time and money more wisely.”

Chad Carsten, MDM Support, KCPL/Westar Energy

About Implementation

A full implementation may take several years and include many changes and adjustments as you go. The key is to have a solid roadmap, but to stay flexible and nimble enough to adopt to changing circumstances and new information.

Recommended Meter Features

- Bidirectional capability
- Remote connect/disconnect switch
- Remote over-the-air upgrade capability
- Voltage reads
- Amperage reads
- Temperature threshold exceeded events or alarms

ADVICE + INSIGHTS

Pace your meter delivery. Coordinate meter delivery to the installation schedule so you don't have all your meters sitting in a warehouse for years.

Start with the basics. It may take a while to get where you want to go. Start by getting all your meters to read daily. You can store other information from the meters and acquire the skills and tools needed to manage it as you evolve.

You will need a meter test shop. You will need to build a robust test environment to physically test and vet meter upgrades and functionality before deploying meters on your system. You want to make sure the upgrades or new functionality do not overwhelm (or break!) your system. This may be new for your IT staff.

Stay up to date on software and firmware changes. There will be many software and firmware updates right from the start of your deployment and they should be implemented in a timely manner even during implementation. Don't underestimate the frequency, testing, and resources required to support these upgrades.

Collect more data from the start. Even if you will not be using it for a while and it might seem like it has no purpose, historical data has many uses including responding to customer complaints, regulatory issues, lawsuits, and analytics. In addition, you will not have to reconfigure the meters at some point down the road when you do want the additional data. Planning ahead will avoid the need for time consuming meter re-programs in the future.

Go slow with configurations. Once you flip the switch, there's a lot of information coming in and it can be overwhelming. Think about what data you will bring back, how many reads, and at what intervals so you aren't inundated. Consider doing a small sample of meters first so you understand how much data will be collected.

Ameren Illinois Digital Network and Meter Test Lab

Ameren Illinois uses their Digital Network and Meter Lab to test and verify application upgrades, firmware, metrology, and more before implementing changes to any part of their system. This lab environment is also used to test new devices and simulate outages, alarms, flags, and events. It is just one of 12 test environments, and a key environment used in verifying, managing, and supporting the AMI solution. This lab is in addition to the Meter Shop lab that is used by the metering engineering team for testing and validating AMI meter and module functionality as well as developing and verifying new meter programs.

About Meter Settings

A smart meter is a mini computer at the grid edge capable of collecting and storing a variety of data—even when the meter is not able to communicate. Different brands also have different capabilities and features that allow utilities to customize their settings, and even change them once the meters are installed. However, utilities with experience with AMI will caution those starting their journey to put some thought into programming your meters. Programming the meters wrong could result in useless information flowing into your system, or equally as bad, missing important information that you should be collecting. Programming the meters up-front is less time consuming and less expensive than having to reprogram the meters after installation (even if it can be done remotely).

How do you handle daylight savings time?

Do the meters make the adjustment internally or when the data is imported are the timestamps adjusted? Decide this detail before you install the new meters or you could end up having two neighbors with load curves that are shifted by an hour. If you end up having more than one meter vendor, you will find that some switch the meter clock automatically and others do not.

ADVICE + INSIGHTS

It takes coordination. It is important to have coordination between IT, OT, and your meter shop to ensure that the meters are programmed correctly from the start. You want to make sure you are including the right data and features to meet the goals across your organization.

Consider future data needs. Think about what data you will want now and in the future. If you are only focused on measuring usage/meter reading and then decide you want to bring back voltage or current, it can take time to implement programming changes (i.e., to reprogram the meter to bring back additional data).

Keep intervals consistent. The fewer number of meter programs you have to manage (i.e., all meters on 15-minute intervals rather than some on hourly and others on 15-minute intervals) the easier it will be. You may want to have different intervals for different customer types, but utilities have found there is value in having the same intervals across all customers. One utility said that looking back, they wish they would have set up the meter for more data and consistent interval times.

Integer reads might not be sufficient. You might need to include the decimal point. For some instances, integer voltage reading will be sufficient – like for voltage sags – but when looking at small voltage changes – for transformer mapping – the integer voltage values are not enough.

There will be some trial and error. Depending on your meter settings, you might get too much or not enough useful information. You might have to play with settings to get the ones that work for you and to find the right balance. Will you wait 10 days to react to non-communicating meters or 5 days? Will you set sag/swell alerts at 5% or 7%? You will have to determine the sweet spot for your business.

Determine how best to perform the meter demand reset. Ameren Illinois has their meters configured to perform a demand reset via the meter program in the meter at midnight each night. Performing this function in the meter was preferred and believed to be more predictable than performing a demand reset via the AMI application and network. The customer system then determines the appropriate demand for proper application of the rate for billing.

Recognize that the technology has its limitations. Smart meters aren't perfect for every customer's location. An extremely hot mechanical room or exposure to waves from a hospital's MRI machine can impact the performance of a meter. If multiple truck rolls are required to the same customer location, make sure to consider environmental factors in addition to meter settings.

Do You Need a Meter Data Management System?

That was a question asked by a participant in the Working Group. The answer from other utilities was “not necessarily;” but you do need a way to manage your meter data, and a meter data management system (MDMS) has many benefits.

You will need to make a decision about meter data management, but maybe not right away. Some utilities in the Working Group deployed their MDMS at the same time as their AMI deployment because they wanted to use the data right away; others tackled integrating the MDMS with billing only after successfully deploying the meters.

What can an MDMS do?

A MDMS is a transactional database primarily used to validate and store data from the meters; it “normalizes” data (i.e., put it into a standard format) that comes from multiple sources or meters with different settings. The MDMS serves up the data to billing and other systems, such as an outage management system (OMS), that use the data for various utility programs and functions. Depending on the bill calculation method and the billing product you use, a MDMS might be required. If you are billing from interval reads (summing hourly reads to get total usage), you will need a MDMS to calculate and verify the data. If you bill from monthly reads, a MDMS might not be necessary.

More than a billing system, a MDMS also allows utilities to gather meter health information and other data, and it can be used to run calculations and conduct queries on the data. Meter health is reported through events and alarms (i.e., temperature, voltage momentaries, reverse power, voltage sags and swells, etc.). The MDMS can also push data to the customer web portal, integrate with other systems, and support many analytical functions..

Pros and Cons

While a MDMS is a powerful tool, you need to be careful about how you are using it. For example, it is possible to write large queries that can shut down your system. To avoid this, some utilities copy the data into a data lake or warehouse for analytics. Some utilities struggle with getting the data out of their MDMS or getting the reports that they need, while others found their MDMS easy to use. Be aware that the reports an off-the-shelf MDMS generates might not be the reports you need, or they may be more than you need. Because these systems tend to be geared towards the needs of larger utilities, they may not be as cost effective for smaller utilities.

Figure 2 shows a how a MDMS integrates with other components of AMI and other utility programs or systems.

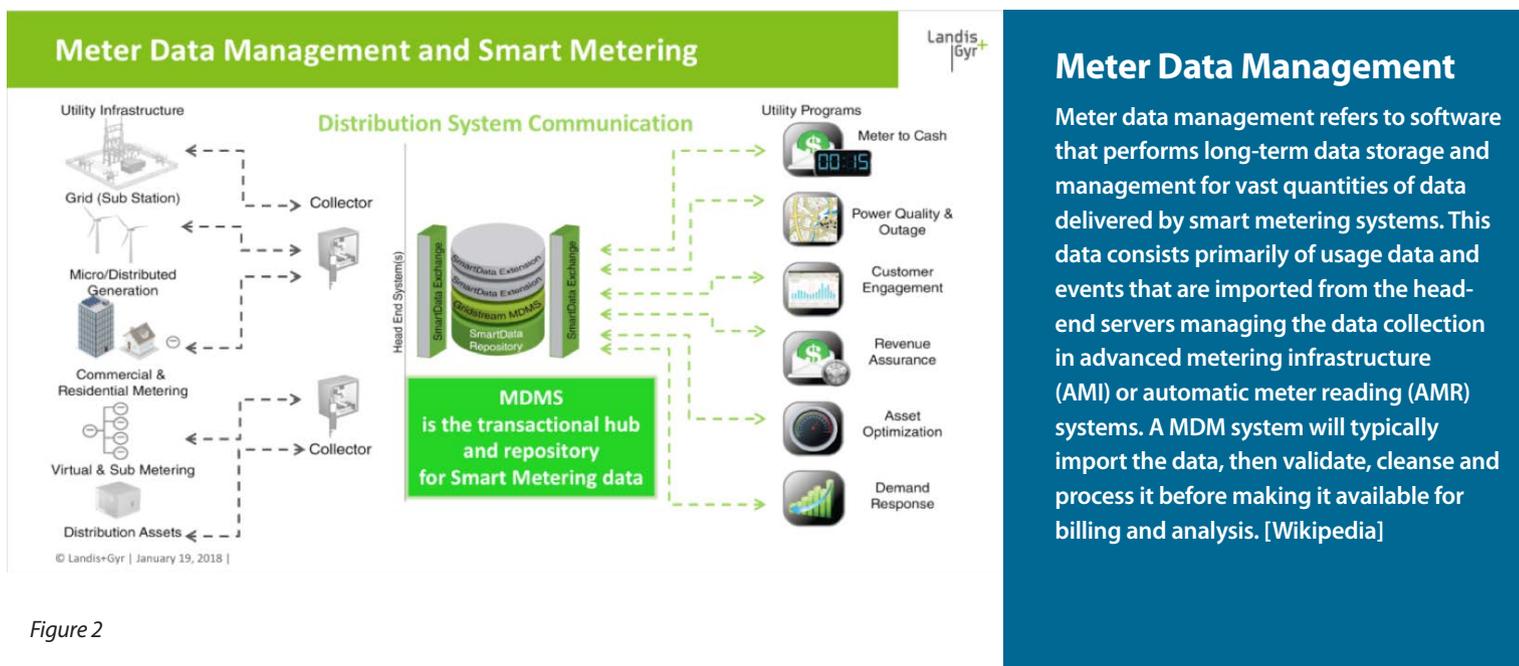


Figure 2

Meter Data Management

Meter data management refers to software that performs long-term data storage and management for vast quantities of data delivered by smart metering systems. This data consists primarily of usage data and events that are imported from the head-end servers managing the data collection in advanced metering infrastructure (AMI) or automatic meter reading (AMR) systems. A MDM system will typically import the data, then validate, cleanse and process it before making it available for billing and analysis. [Wikipedia]

About the RFP

The number one thing to include in your Request for Proposals (RFP) is time. One utility said their RFP process took a year from planning their system to signing contracts with their vendors. They also suggested that you put the time in upfront—about six months—to put together your team, identify your use cases, evaluate your processes, and develop your request for proposals. Allow about three months for your proposal to be “on the street,” or open for responses, and another three months for vendor demonstrations and contract negotiations. Your budget should include the staff (and possibly consultants) needed to do the work to prepare a detailed and comprehensive RFP.

ADVICE + INSIGHTS

Consider hiring a consultant to help write the RFP. Utilities have found this worth the cost. Use one who has successfully helped many utilities; they can provide an RFP template that will save you time and help you think of the details.

Check your vendors’ references. Talk to someone at another utility who has used the vendors you are considering, but do not let the vendors broker the conversation! Ask your vendor for their complete customer list and you call whoever you want.

Define the data you have available. The vendor must be able to accurately estimate costs based on available data. If granular data is not available, the vendor will have to develop it through other sources.

Include integration information. Know what specific vendors that the AMI vendor must work with; there needs to be seamless integration with existing systems. For example, integrating with the OMS is a core function of AMI that utilities are finding tremendous value. Consider including automatic generation of outage tickets as one of the use cases that you specify in your planning.

If a smart city is in your future... Ask if the network can support other vendor products including smart streetlights, parking, and other smart city features.

Don’t buy a flip phone. Really look at the technical details of the meter – there are differences! Understand the capabilities of each meter such as storage, memory, etc. If the meter is lacking a capability, ask why and find out when it might be available. Beware of the phrase “under development.”

Develop your use cases thoughtfully. Your use cases will drive the functionality that you will specify in your RFP. Vendors will want use cases to prepare their proposals. Include future use cases, too!

Recommended Resources for Getting Started

- EPRI has an online database that captures and tracks the status regarding smart meter/AMI deployments. It provides a platform for sharing information and collaboration. EPRI’s database is available to both members and nonmembers and includes use cases from over 85 utilities, representing over 150 million meters.
- The US Department of Energy’s Office of Electricity DSPx Initiative provides decision makers with a three-volume set of reports that can help inform investment decisions in grid modernization and provides information on grid architectural frameworks. For more information, visit <https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx>

Appendix A

DOE Working Group Participants

This list includes all parties who registered for a working group conference call, attended a regional meeting (or sent staff to one of the meetings), or participated in an interview with the leadership team. The leadership team would like to thank everyone who supported this initiative, especially those who shared their experience with the readers of this guide.

John Ainscough Xcel Energy	Tom Bialek San Diego Gas & Electric	Justin Chamberlain CPS Energy
Raidel Alfonso Florida Power & Light Company	Chris Bilby Holy Cross Energy	Baldwin Chan Pasadena Water and Power
Luwil Aligarbes Farmington Electric Utility System	Phil Bisesi ElectriCities of North Carolina	Kewen Chen Golden Spread Electric Cooperative
Keith Anderson New Brunswick Power	Ian Bledsoe Clatskanie PUD	Kellee Christensen Pacific Gas & Electric
Daniel Anglin Farmington Electric Utility	Mark Bonfiglio Energy Corporation	Nichlas Corsetti National Grid
RJ Ansell Gainesville Regional Utilities	Russ Borchardt Xcel Energy	Kim Cullen Santee Cooper
Richard Aslin Pacific Gas & Electric	Don Bowman Wake EMC	Marquita Culross Carroll White REMC
Dawn Baker Arizona Public Service	Kevin Boyd Alabama Power Company	Adam Cutter Central Main Power
Tige Ballard Middle Tennessee EMC	David Bratzler Pasadena Water and Power	Kevin Ding CenterPoint Energy
Daniel Barbosa Florida Power & Light Company	Laney Brown Concentric Energy Advisors	JP Dolphin Pacific Gas & Electric
Clare Bargerstock Northern Virginia Electric Cooperative	Ruth Calderon Golden Spread Electric Cooperative	Mauro Dresti Southern California Edison
Obadiah Bartholomy Sacramento Municipal Utility District	Ward Camp East Fork Group	Todd Eisenhauer National Information Solutions Cooperative
Camryn Batchelor Piedmont EMC	Mark Carpenter Oncor Electric Delivery	William Eillis Exelon Utilities
David Beaulieu Gainesville Regional Utilites	Bob Carroll American Electric Power	Harry Emmerson Oklahoma Gas & Electric
Jennifer Beechinor Pacific Gas & Electric	Chad Carsten Westar Energy	Mark Esguerra Pacific Gas & Electric
Wesley Bennett Edmond Electric, Edmond Oklahoma	Mitch Cason Georgia Power	Taha Fattah City of Palo Alto
Daniel Bethapudi City of College Station	Julie Cerio Pacific Gas & Electric	Beth Fondell Owatonna Public Utilities

Sam Gafford Direct Energy	Timothy Hunt Jacksonville Electric Authority	Tom Lovas NRECA
Arthur Gonzalez Austin Energy	Anthony James Southern California Edison	Drury Mackenzie Avangrid
Jennifer Goncalves Pacific Gas & Electric	Michael (Scott) Jarman Austin Energy	Michael Marlatt Sacramento Municipal Utility District
Wayne Gossage Jefferson Energy Cooperative	Bryce Johanneck Cass County Electric Cooperative	Kent Mathis Jacksonville Electric Authority
Wesley Granade Georgia Power	Spencer Jones Puget Sound Energy	Philip McAvoy Salt River Project
Rod Griffith Entergy	Brannndon Kelley American Municipal Power, Inc.	Michael McCleary Florida Municipal Power Agency
Alejandro Gutierrez Florida Power & Light Company	Dan King Xcel Energy	John Mead Pacific Gas & Electric
Allison Hamilton NRECA	Curtis Kirkeby Avista Utilities	Martha Mitchell CPS Energy
Hugh Hamilton Jamaica Public Service Company	Gustavo Klinguefufus Copel	Terry Mooney American Electric Power
Bryan Hannegan Holy Cross Energy	Joanne Kolb Powder River Energy Corporation	Bryan Moorman Poudre Valley REA
Angela Hare Cumberland Electric Membership Cooperation	Yuvaraj Kondaswamy Central Rural Electric Cooperative	Suzanna Mora Pepco Holdings
Donny Helm Oncor Electric Delivery	David Kuhlmann Ameren	Joel Murphy American Electric Power
Christian Henderson San Diego Gas & Electric	Martin (Marty) Kurtovich California Public Utilities Commission	Bill Muston Oncor Electric Delivery
Giovanni Herazo Florida Power & Light	Douglas Lambert NRTC	Arlen Orchard Sacramento Municipal Utility District
Dave Herlong Florida Power & Light	George Leach Northern Virginia Electric Cooperative	Yania Paez Florida Power & Light Company
Todd Hiemer Central Electric	Robert LeTellier Holyoke Gas & Electric Dept	Thomas Parker Fort Pierce Utility Authority
Larry Hopkins Piedmont EMC	Yi Li PPL Electric Utilities Corporation	Chad Parker Gainesville Regional Utilities
Patrick Howle Santee Cooper	Travis Lincoln Westar Energy, Inc.	Thomas Parker Fort Pierce Utilities Authority
Jennifer Hungate Salt River Project	Brad Lingen Missouri River Energy Services	Jim Parks Sacramento Municipal Utility District
David Hungerford California Energy Commission (CEC)	Juan Lopez Florida Power & Light Company	Dawn Pascoe Berkeley Electric Cooperative

Jamie Patterson
California Energy Commission

Mateusz Pena
Delta-Montrose Electric Association

Carrie Peters
Jones-Onslow EMC

Jonathan Pettit
Oncor Electric Delivery

William Phillips
Entergy

Aaron Ponder
PacifiCorp

Jared Price
American Municipal Power, Inc.

Glenn Pritchard
PECO

Mike Putt
Florida Power & Light Company

Clint Rapier
Empire Electric Association, Inc.

Matt Reed
Southside Electric Cooperative

Justin Regnier
California Energy Commission

Derl Rhoades
Alabama Power Company

Anthon Rivera
Southside Electric Cooperative

Arielle Romero
Sacramento Municipal Utility District

Justin Rowley
Pasadena Water and Power

Tom Russell
Pacific Gas & Electric

Joel Rutsky
City of Lake Worth Utilities

Ted Salazar
Silicon Valley Power

Randall Schmidt
Oncor Electric Delivery

Judith Schwartz
To The Point

Denise Senecal
Pepco Holdings

Joshua Snoddy
Holy Cross Energy

Kari Spotts
Longmont Power & Communications

Steve Steffel
Pepco Holdings

Joel Stitt
Salt River Project

Pamala Sullivan
American Municipal Power Partners

Shiva Swaminathan
City of Palo Alto

Daniel Swingle
Northern Virginia Electric Cooperative

Joe Tellez
Tacoma Public Utilities

Tony Thomas
NRECA

Amanda Townsend
Oncor Electric Delivery

Vicki Trees
Landis+Gyr

DwayneTurner
Centerpoint Energy

Iker Urrutia
Avangrid

Cairo Vanegas
Florida Municipal Power Agency

Joshua Wells
Southside Electric Cooperative

Scott Whitmire
Southern Company

Tishekia Williams
Duquesne Light Company

Lincoln Wood
Southern Company

Sophie Xu
PECO Energy

Jerry Young
American Electric Power

U.S. Department of Energy Team

Sonja Berdahl
National Renewable Energy Laboratory

Tanya Burns
Arara Blue Energy Group

Eric Lightner
DOE | Office of Electricity

Appendix B

Leveraging the AMI Network to Communicate with Smart Inverters | PG&E EPIC Project 2.26

PG&E's EPIC project 2.26 Customer and Distribution Automation Open Architecture Devices, which is currently underway, successfully developed a cloud-based Client-Server architecture using the IEEE 2030.5 protocol, APIs for the command and control of various end devices, and protocol adapters to communicate with a multitude of end devices. PG&E was able to successfully connect to, monitor, communicate with, and control end devices using lab and field tests for a variety of use cases

The project demonstrated that PG&E's AMI network has additional bandwidth available and can be used for purposes beyond billing, and that installing or interconnecting devices to the AMI network could ultimately reduce equipment installation costs. Because the AMI network coverage is 99.5% of PG&E's service territory, it is seen as a reliable, lower cost network solution, specifically for network capital spending, maintenance operation spending, and especially telecommunications costs. The AMI mesh network's built in redundancy has the capability to improve PG&E's ability to monitor field devices, to more quickly identify problems or incidents, and to improve response time to events.

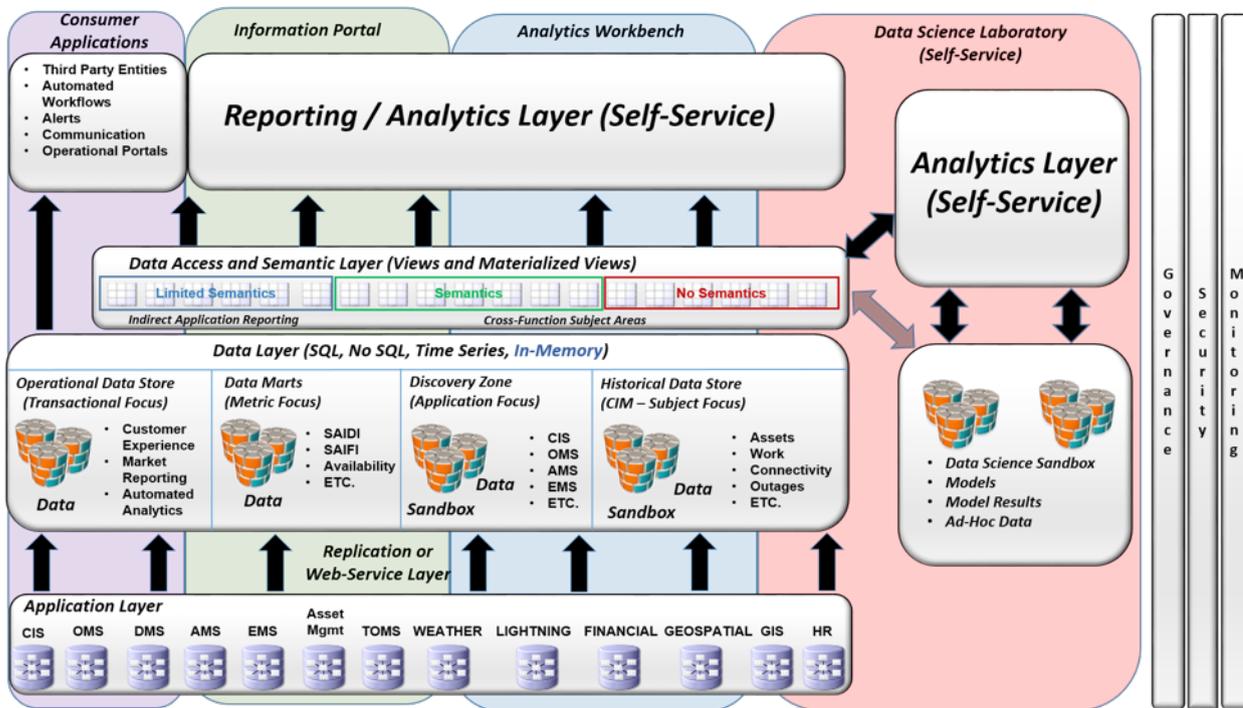
USE CASES AND FIELD TESTS

- **DER telemetry and SCADA use cases:** To meet the latency requirements for DER telemetry and SCADA use cases, PG&E redesigned the AMI network to have a single hop by and to transmit the data directly through a network node using the least number of endpoints. It was found that depending on the DER Class, various latency requirements could be determined and applied (e.g., slower latency for DER Class 2), and the AMI network could be designed accordingly. In addition, a SCADA over AMI solution can be a potentially complementary solution to SCADA in areas where other SCADA solutions are not available.
- **Solar Smart Inverter:** This use case demonstrated the use of PG&E's AMI network to communicate with and control solar smart inverters. It was selected because of its potential to improve system reliability. It was tested in both lab and field environments.
- **Direct Acquisition and Control Telemetry Solution:** This use case demonstrated the direct acquisition and control telemetry solution using PG&E's AMI network for medium-sized energy generation projects under 1 MW (i.e., 200 kW). It was selected because of its potential to reduce costs and was tested in both lab and field environments.
- **Distribution Automation /SCADA Overhead and Underground Intelligent Electric Devices (IEDs):** Demonstrating the use of PG&E's AMI network to communicate with, control, transmit data of, and upgrade firmware over-the air onto overhead and underground devices in PG&E's system, the use case was selected because of its potential to improve system reliability and was tested in the lab environment.
- **Radio-Frequency Identification Tags (RFID tags) Over AMI Network:** This use case demonstrated the use of PG&E's AMI network to communicate with RFID equipment (readers and taggers) over the network. It was necessary because of the network's potential to reduce costs and it was tested in both lab and field environments.
- **Cybersecurity penetration tests:** The field test performed during the project showed the need for properly hardened infrastructure that leverages secure-boot functionality, device encryption, and a strong password complexity policy. Doing this required an upgrade and hardening of the IoT-Router software before moving to a production environment. Cybersecurity for the systems between PG&E cloud and headend server were hardened and resolved using IPsec VPN over PG&E Data pipe to replace IPsec VPN over internet.

Appendix C

Oncor Data Analytics Platform

Figure 1: Oncor Data Analytics Platform



Source: Oncor

The Definition of a Data Store, Sandbox and Lake

Data Store

A separate, protected environment for sequenced data that is separate from, and will not impact, billing data. The data store is the mechanism for giving access to users; whereas, the MDMS is the transactional system. The data store enables predefined tables for users so that no IT skills are needed to access the data, and it was built internally because it brings data from multiple systems together. Oncor's data store is 300 terabytes and it contains two years of data.

Data Sandbox

Data is replicated and put it into a discovery zone where development and experimental work can be done rather than against the data store. There is also a process to validate what algorithms can then be operationalized. Without a data sandbox, engineers tend to develop the algorithms on their local machine, which doesn't allow for scaling the analysis or easily sharing it across teams.

Data Lake

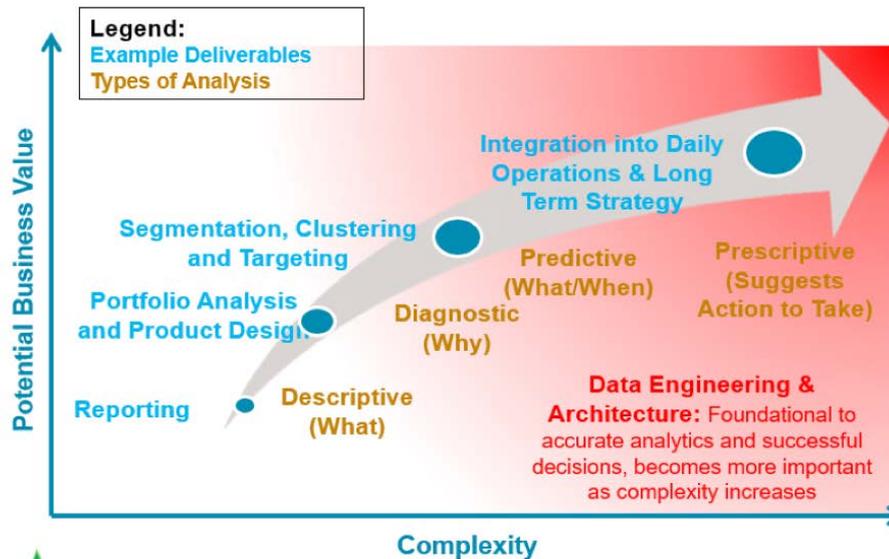
Contains unsequenced files of data. Tools hook onto the data lake to pull the data individuals want to convert into actionable information. Data stores can also have tools that hook on and pull the data, but the difference is the structure.

Appendix D

The Evolution of Analytics

Source: JP Dolphin, PG&E

The evolution of analytics is a series of increasingly complex steps that allow you to unlock more and more value from the data



Artificial Intelligence (AI) and Machine Learning (ML) are techniques, not deliverables. AI can be used to generate descriptive, diagnostic, predictive, or prescriptive analysis and may be combined with task automation.

Descriptive Analytics. Answers, “What happened?” It provides insight on the state of the system today or what’s been going on historically. There might be some analysis, like averages or basic trends over time. It provides insights for improving processes and operations. Skills needed: query, manipulation, analysis, and visualization to identify trends and risks. Computer programming languages and tools might include SQL or D3, Tableau or Power BI, and SAS, STATA, MatLab.

Diagnostic Analytics. Answers, “Why did this happen?” While diagnostic analytics is still historic, it’s introducing more statistical analysis. Diagnostic analytics can be performed using point-and-click interfaces, and creates analysis and formulas, but no code is being written. Descriptive analysis can be paired with changes in the broader environment to identify correlation and potentially root cause. Theft analytics is a good example of diagnostic analytics.

Predictive Analytics. Answers, “What will happen?” Predictive analysis prepares for future scenarios. It uses descriptive and diagnostic analytics to understand what’s happening and why to inform what will happen in the future to enable proactive corporate positioning and action. Predictive analytics requires subject matter expertise and the ability to analyze multi-structured data sets as well as apply advanced statistics. Staff need skills in machine learning in addition to programming skills such as R or Python. Predictive maintenance is an example of predictive analytics.

Prescriptive Analytics. Answers, “What should we do?” Prescriptive analysis allows for the development of recommended actions based on what predictive analytics indicated will happen. Data and analytics are used along with the operational perspective or understanding to make an informed decision on which options are the most advantageous. Prescriptive analytics requires huge volumes of data, and could require the use of cloud computing infrastructure. Prescriptive analytics and machine learning algorithms make it possible to determine things like which transformers to order or which crews to schedule for the lowest customer complaints. Requirements include deep machine learning, optimization, and statistical expertise, and an understanding of R, Python, and Tensor Flow.

Artificial Intelligence. More advanced utility Internet of Things (IoT) analytics solutions are entering the market and can be applied to legacy systems and new data flows using edge computing, cloud computing, machine learning, and artificial intelligence (AI) to unlock valuable insights and drive operational efficiencies.

