Enabling the clean energy transition: Planning for next–generation advanced metering infrastructure and grid technologies

A perspective on how utilities and consumers can work together using new metering technologies to achieve decarbonization goals along with a more resilient grid.

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This paper examines the evolution of advanced metering infrastructure (AMI) from a collection of digital meters that communicated a limited amount of data and performed a few routine tasks, to a network of powerful edge computing devices that can execute complex power-related software applications and control energy–producing and energy–consuming devices on their own, in real time. The paper looks at how electric utilities plan to take advantage of the new technologies and work collaboratively with their customers to reach decarbonization goals and a more resilient grid.

History of AMI up to 2021

For more than a century, public utilities had collected a minimal amount of data from their largest population of customers: residential dwellers. Manual reading of mechanical meters for the purpose of billing provided a single-usage value (also known as a meter read) performed, on average, six to 12 times per year. Off-cycle reads for maintenance or a change in occupancy added a small number of additional data points, but not enough information to know how or when utility customers required energy or water. Manual meter reading required a high degree of logistic support and employees to read the meters; roughly one meter reader for every 5,000 meters, and field crews had to be dispatched whenever there was a change in occupancy.

In the first decade of the 21st century, advances in metering technologies brought digital capabilities to the mass utility market and the era of advanced metering infrastructure (AMI) was born. AMI meters, also known as smart meters, allowed the meter to transmit energy consumption data over radio frequencies on a daily schedule, or on demand, providing the receiving utility hourly or quarter-hour energy data. AMI meters were able to communicate meter health status signals and automatically turn power on or off at a residence. The ability to transmit energy usage and control the power flow reduced the need for human meter readers and field crews to disconnect and reconnect a meter, saving transportation costs and reducing carbon emissions. Between 2000 and 2010, approximately 20 million AMI meters were installed in the United States. Between 2011 and 2021, 95 million additional AMI meters were installed in the United States alone.[1] We refer to the time between 2000 and 2021 as the age of "AMI 1.0."

Within a few short years of implementing AMI 1.0, utilities transformed from being primarily providers of energy or water to becoming information management businesses. This was enabled by the volume of data being received from the meters and supporting network devices growing to more than 2 terabytes of new production environment data per year for a utility with 1 million meters collecting hourly reads. Soon, smart meter data was combined with outage systems, geospatial systems, asset management systems, weather data, and operational systems to provide a near-real-time picture of the health of the distribution grid. Some utilities used advanced analytics based on meter data to predict failures of field equipment such as transformers, and others used the data to identify where customers had tampered with the meter and were stealing electricity. CenterPoint Energy, for example, reported[2] collecting $4.5 million in additional revenue from 2012 to 2014 from the identification of slow meters, unregistered meters, and electricity theft.

The operational savings from AMI 1.0 have been significant. An analysis of AMI programs with more than 500,000 meters from the Smart Grid Investment Grant Program[3] found an average saving of $10 per year per meter, which, when multiplied over a 20-year recovery time period, showed those utilities would recover 65% to 75% of the initial cost of the program. Most of the savings came from the retiring

or redeployment of meter readers and the reduction of truck rolls (service calls) to residences. Some utilities reported a decrease of as much as 85% to 95% in service calls[4] once AMI 1.0 was deployed. This reduction in truck rolls has a direct impact on decarbonization with fewer gas-powered trucks on the road.

From a customer experience perspective, the anticipated benefits from AMI 1.0 included, but were not limited to:

- Increased accuracy of billing
- Faster connections and move-outs
- Implementation of flexible billing programs such as time-of-use (TOU)
- Real–time access to electric consumption
- Automated outage and predictive restoration notifications
- Pre-payment for energy

While some of these benefits were achieved in parts, a 2020 survey by ACEEE[5] determined that out of 52 utilities surveyed, only two of them realized the full potential of AMI data in most respects.

In our discussions with AMI 1.0-enabled utilities, one area that did not achieve the hoped-for adoption was in home area networks, also known as HAN. This was also noted by Greentech Media:[6] With HAN technologies like in–home displays, also known as IHDs, homeowners could connect an in-home display with a basic LED graphic to their smart meter to show electricity costs and usage in real-time with the idea that the customer could manually switch off energy–consuming devices to reduce costs. Homeowners were also able to install a network gateway connected to their meter that would be controlled by a smartphone app to control appliances with outlet adapters and smart thermostats for enhanced complex energy management. While HAN was a strong start in educating customers about their use of energy, they were not adopted widely enough, and customers often stopped paying attention to HANs, according to a 2016 report[7] from the Department of Energy (DOE).

So, who benefited from first-generation AMI? According to the DOE in its 2020 report,[8] most benefits were received by the utilities from having increased efficiency in utility operations that the customers did not directly experience. Benefits were obtained from a reduction in meter readers, deferment of investments such as new generators, and reduced energy theft. Since AMI meters also monitor voltage, large electric utilities including Duke were able to use this data to implement conservation voltage reduction (CVR),[9] which typically saves 1%–3% of energy. Benefits customers saw in some (not all) cases were self-service (the ability to schedule a move-in/move-out online), the capability to receive outage and restoration time notifications, dynamic pricing plans tailored to consumer categories, and bill forecasting notifications. In 2016, the DOE reported[10] that customers enrolled in dynamic pricing saved between between $5 and $500 annually on their electric bill, which met the target of an average 5% reduction in annual billings.

What is the necessity for AMI 2.0?

The first AMI meters were installed between 2000 and 2010, during what we are calling the "first wave." These AMI meters and their associated internal batteries had a life expectancy of 20 years, which was the life span commonly amortized in AMI business cases because many brands of electric smart meters require batteries to store meter information in the case of a power loss. Deloitte's research shows that the life span for meters implemented prior were in fact lasting between 15 and 20 years, as expected; however, the failure rates were on the rise as the meter life spans approached 20 years. As a result, early adopters of AMI 1.0 are "doing the math" and have started planning for meter replacements because it can take three to five years to plan for any large AMI implementation. In addition, COVID-19 has resulted in potential supply chain risks where utilities may be competing for replacement meters. Additionally, according to a 2021 report[11] from the Edision Foundation's Institute for Electric Innovation, there are nearly 25 million residences without AMI meters that are likely to compete for those inventories as well.

So, the question becomes, why don't the utilities simply extend the life span of the meter by replacing the batteries and reinstalling on-premise? Unfortunately, replacing the internal batteries on the meters is, in most cases, not practical. Some meters are sealed for harsh weather conditions, and breaking the seal would disrupt that protection. Other meters would require disassembly of the meter to access the battery, and it often is wired to the motherboard. Gas meters are powered by their batteries and, for similar reasons, including gas safety, are not practical to be swapped out. This necessitates the replacement of the entire meter in most cases. For electric meters without batteries, such as those manufactured by Sensus, the impetus to install newer meters is primarily driven by the necessity to provide the advanced capabilities of the next generation of meters.

Deloitte performed an assessment of 11 electric and gas AMI deployments, each with more than 500,000 meters, and found that utilities deployed around 2,920 meters per day on average. A meter installer would average around 45 meters per day. So these utilities needed, on average, 65 installers per day. For a utility that has only a few tens-of-thousands of AMI meters, replacing the meters could be performed as an aggressive replacement strategy with much fewer installers, but for a utility with more than half-a-million premises, the replacement approach and time frame will likely need to be performed similar to how they were originally installed to align to the actual ages of the meters. This round, the utility has an advantage if it recorded the deployment routes from the first installment.

Beyond the need to replace meters as a result of potential battery failure, the next wave of meters is part of a robust technology stack that we are calling "AMI 2.0." The next generation of residential meters as part of AMI 2.0 are becoming edge computing devices capable of not only recording consumption, but also enabling a better understanding of how electricity is being used or generated behind the meter, in real time. This is enabled by the next generation of meters having faster processors, increased memory, modular communication capabilities, and longer–lasting batteries. This sort of intelligence is increasingly becoming necessary to manage the expansion of complex energy–producing and energy–consuming devices in households worldwide. Local power generation from solar panels, home battery systems, and eventually electric vehicles being able to transmit electricity back to the grid is becoming more common. The Solar Energy Industries Association reported[12] that by 2030, 13% of all homes in the United States will have solar panels. Electricity consumption is increasing to power electric transportation including cars, commercial vehicles, bikes, and scooters. Figure 1 depicts a summary view of the capabilities Deloitte anticipates from AMI 2.0-enabled meters.

FIGURE 1

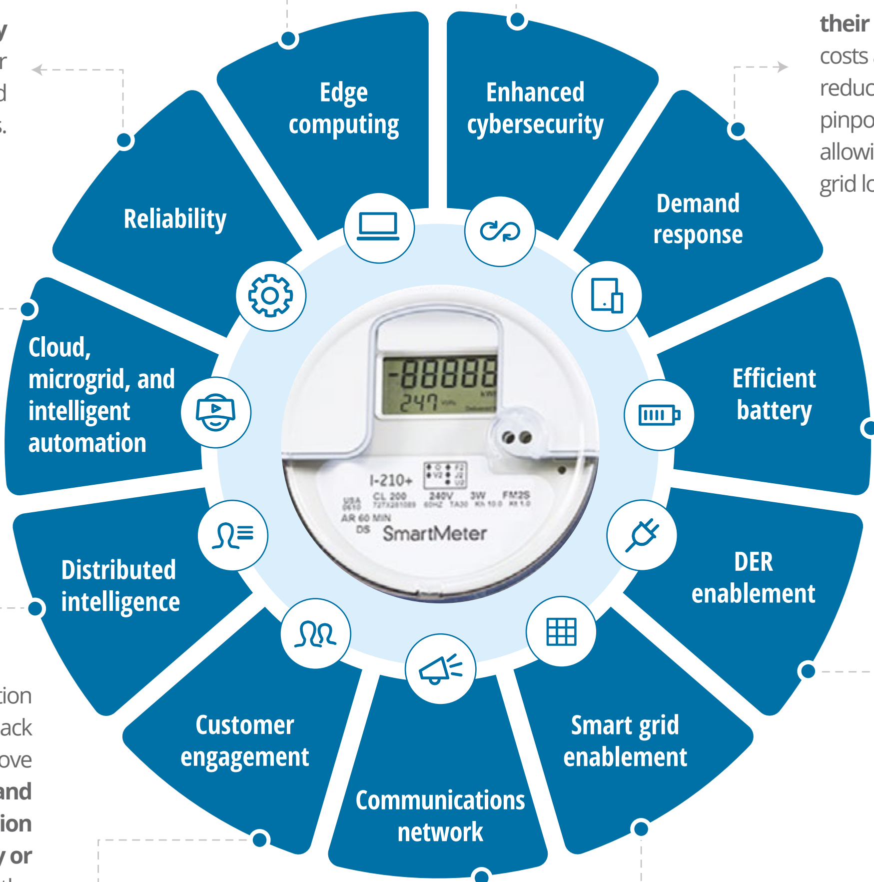
Summary view of the capabilities Deloitte anticipates from AMI 2.0-enabled meters

To have enough **edge computing power with access to the raw data allowing for high-resolution waveform data**, edge computing, and flexible networking capabilities along with more secure over-the-air updates.

Advanced cybersecurity technologies will need to be developed and incorporated into the design of different architectures that bundle these capabilities, given the increased exposure to **cyberattacks inherent in digital and software-centric grid systems**.

Real-time, dynamic energy data could **allow customers to analyze their device-level usage** when costs are higher or incentives for reduced demand are provided to pinpoint device-level consumption, allowing utilities to target flexible grid loads.

Improved power quality and resilience, quicker outage restoration, and self-healing capabilities.



To support advanced technologies like **cloud, microgrid, and intelligent automation**.

The advancement of technology can support **efficient battery life and optimized data flow**.

To embrace automation throughout—especially back office—to improve operational efficiency **and enable data aggregation based on territory or function** to enhance the accuracy of response efforts.

Newer meter capabilities measure **the value of DER, as rooftop solar and behind-the-meter batteries integrate electric vehicles** and demand-side flexibility into grids.

An improved and advanced communication network (5G) that serves as a foundation for smart grid technology and programs such as distributed energy resources, demand response, and electric vehicle charging. Launch next-gen services to take advantage of AMI technology advancements and digital transformation to **address difficult-to-reach areas, as well as cybersecurity and safety needs**.

Improved customer awareness of consumption, pricing, and data-driven insights that enable a variety of new customer services, such as smart home energy management, load control, time-varying pricing, budget billing, and outage/usage alerts.

Low-latency communications between grid and customer devices that are **real-time, high-peak throughput, high density, and wide coverage**.

Note: DER = distributed energy resources.
Source: Deloitte Consulting, 2022.

Customer benefits from AMI 2.0

While AMI 1.0 delivered tangible value to the consumer, what consumers want is for the benefits to be automated and easy to acquire. While the 2016 DOE report[13] showed that customers largely ignored their IHDs, it also revealed that customers warmed to the idea of having a programmable control thermostat (PCT) directed by the utility after they learned more about the utilities control strategy.

With new capabilities, such as being able to communicate via Wi-Fi, meters can be paired with utility smartphone apps to provide a variety of services that do not require internet connections. Salt River Project in Arizona recently demonstrated this capability with Landis+Gyr meters that allowed consumers to pre-pay for electricity and set thresholds for consumption on the app that could, in turn, control devices inside the home to manage customers' bills.[14]

These capabilities are intended to not only provide additional ways for an electric utility to provide a smarter grid, but also to give residential customers far more benefits than AMI 1.0 provided. For example, a meter that can analyze device-level energy usage in real time could allow a customer to program the meter to instruct a high-consumption device such as an electric vehicle charger to only charge below a rate set at a specific threshold based on the vehicle's current charge level and the price of energy.

Today's meters can make better use of disaggregation programs as well. Also known as non-intrusive load monitoring, these are programs that can detect the type of appliances running behind the meter based on signal processing signatures detected by artificial intelligence (AI) algorithms. AMI 1.0 enabled consumers to sign up for programs like this through white-label vendors, such as Bidgely or Opower, where the reports were provided at the end of the month (or whenever a customer logged in to their white-labeled site or app). With a computer on board the meter, disaggregation can take place in real time. Landis+Gyr recently partnered with Sense[15] to install disaggregation software onto meters, giving the consumer a home energy management solution that can be integrated with smart home devices such as Amazon Alexa or Google Home. Additionally, for a resident with original wiring, using high-fidelity energy quality data will allow the consumer to know if there are electrical panel issues, where upgraded wiring is needed, or which appliances to replace.

For a consumer with distributed energy resources (DER)—such as solar panels, home batteries, or electric vehicles that can discharge to the grid or use smart inverters —having disaggregation software run on the meter enables the customer to manage and balance the demands on DER equipment according to their preferences. For customers who participate in net metering (putting excess electricity back on to the grid), customers will have more information in real time about the volume of electricity being produced that is allowing the customer to make better decisions on how much and when to store energy versus sell energy. Blockchain technologies have been used in Europe to track and certify who produces renewable energy. An example of this is Iberdrola[16] in Spain, which used Energy Web to track clean energy from several sources using blockchain technologies.

It is also conceivable that by using blockchain technologies to properly attribute distributed energy production, peer-to-peer (P2P) trading could occur between individuals. In P2P, a resident who has energy-generation capabilities could offer a reduced price for electricity to a neighbor, for example, or to others connected to the resident's grid who would agree to the resident's rate. The electric utility could act as a broker and manage the payments while monitoring the grid for reliability. A consumer's energy-producing assets could also become what are known as virtual power plants,[17] allowing an electric utility to draw power from home batteries or electric vehicles during high consumption periods so that the utility avoids having to use small generation facilities known as peaker plants, which often use less clean fuel sources such as coal.

Consumer safety will be a new feature in AMI 2.0. Itron's Riva CENTRON meters now include a software application that provides emergency signals from the electric company to a resident in the event of a weather event, such as flooding, hail, extreme heat, or a planned outage, so the consumer can move their car out of the garage, for example.

Customers can increase the benefits they obtain from AMI 2.0 data by signing up for services that augment their energy data with personal and regional data. Opower by Oracle, for example, provides a service to residents that allows the rate payer to tell its AI-powered analytics solution how many people reside at the premise, and what their incomes are, which can be combined with local demographic data to enable a utility to pinpoint equity pricing structures or other services, or that give the consumer more personalized energy-reduction recommendations. Interestingly, Deloitte learned from Opower that consumers have adapted very well to the use of QR codes because many of us learned to use QR codes to read restaurant menus as a result of restaurant safety measures during COVID-19. This demonstrates how consumers will embrace new technologies that enhance safety and security.

Utility benefits from AMI 2.0

Utilities that deployed AMI 1.0 have already captured the operational benefits and deferment of investments that justified the initial costs. The cost savings from those are now factored into their current financial forecasts. A second round of implementing replacement meters and potentially a replacement collection network may prove harder to justify since there are no longer meter readers to count savings against, and truck rolls for connecting and disconnecting have already been reduced. The exception are utilities that have not yet implemented AMI 1.0, which will benefit from the advanced technologies that their AMI 1.0 counterparts did not have at the time of the first-wave deployment.

Next-generation AMI meters have extraordinary capabilities to contribute to grid reliability.

So, how do electric utilities benefit from AMI 2.0? To start with, the new meter technology has evolved at a crucial time when grid resiliency has become a commonplace topic in the news cycle. The next-generation AMI meters have extraordinary capabilities to contribute to grid reliability that meters deployed during the first wave of AMI 1.0 did not. For example, the first wave of AMI meters captured voltage (at most) with every 15-, 30-, or 60-minute read and sometimes just once a day. Knowing the voltage at as many points as possible, as frequently as possible, on a utility's distribution network can allow the operators to regulate the voltage on the network to prevent higher or lower voltages than desired.

AMI 2.0 residential meters can capture voltage more frequently than their AMI 1.0 counterparts. The latest residential Riva CENTRON meters from Itron, for example, are capable of reading voltage every second[18] giving a much more detailed picture of the health of the voltage at the endpoint. Known as "distributed intelligence," AMI 2.0 meters can make decisions and detect anomalous conditions without having to rely on the data being sent to the utility's back office, possibly hours later. Tampa Electric Company (TECO) recently piloted[19] these meters for three conditions: energy theft, residential neutral fault detection, and high impedance detection. In all cases, the meters outperformed the back-office applications in detecting theft, neutral faults, and high impedance.

With the ability to sample voltage and amperages every second (or on demand), grid operators can now obtain a more accurate picture of their distribution model. With AMI 1.0 providing voltage and amperage readings every 15, 30, or 60 minutes, calculated power factor on a circuit is frequently obsolete, making it more difficult for a utility operator to optimize the voltage on the circuit. The power factor is the ratio of working power measured in kilowatts (kW), to apparent power measured in kilovolt-amperes (kVA). By comparing these figures from meters on a circuit, the utility can determine if the power being consumed is equal to the power demand—the energy delivered by the utility. If the ratio is less than 100% (and it commonly is), energy is being lost. By understanding if this is caused by conditions known as leading (where the current leads the voltage) or lagging (where the current lags the voltage), a correction can be executed by sending voltage and/or volt-ampere reactive (VAR) controls to adjust voltage or cap settings. Imbalanced energy flow can cause some electrical devices to overheat and wear out faster. By having a more accurate view of the energy waveform at the endpoint, such as Landis+Gyr's Revelo[20] meters can provide, a more accurate picture of energy quality can be derived even to the point of distinguishing between an issue caused by vegetation or a field equipment problem like a cracked insulator. Having a more accurate picture of the actual connectivity model through more detailed data will help a utility reduce costs by spending on upgrades only where and when needed.

For the practical reason of not wanting to flood the AMI network with unnecessary data, the meter would not transmit to the back office reads from every second; they would instead be processed on the meter and only important deviations would be sent in real time. However, if a utility were to want a read from every minute, the storage required would grow from our estimates of 4 terabytes per year per million meters for an hourly read to 55 terabytes per year for minute reads (i.e., 60 reads an hour). Combine that with backups and test environments and a compelling case could be made for the use of cloud technologies where storage can be added on demand. Meter manufacturers are preparing for this through partnerships with cloud providers. Itron has partnered with Microsoft Azure[21] while Landis+Gyr has partnered with Google GCP,[22] for example.

Another problem AMI 2.0 solves is in the identification of where a high-voltage residential electric vehicle (EV) charger is located and whether or not the circuit it's on can handle it. Electric vehicles draw a lot of energy when charging, and today utilities may have to rely on DMV data to know if there are EVs owned by residents in their service territory. This information may not always be accurate because the EV may not always be stored at the location the owner lists on the title. If a consumer pulls a permit for an EV charger and the permitting department or the installer notifies the utility, the utility will know that a charger is being installed. However, with AMI 2.0–level data, the utility would be able to know before a consumer installs it whether or not the circuit it's on can handle it without needing to be upgraded. Without being notified of a charger installation, a utility can use disaggregation software or advanced analytics to identify the charger exists once the EV is plugged in. Imagine in the not-too-distant future when thousands of EVs in a neighborhood are charging simultaneously. Customers and utilities will need to collaborate using the information provided by AMI 2.0 to allow the utility some control over how much charging can occur[23] simultaneously based on factors such as time-variant pricing, energy availability, and customer preferences.

To improve grid reliability when energy is fluctuating more than usual, such as during a storm event or seasonal shifts in populations, utilities can benefit from being able to perform phase detection at the endpoint of a circuit—the meters. Phase detection measures the load on a wire and a neutral wire. With AMI 2.0 meters having an accurate picture of the phase a meter is on, utilities can avoid having to send crews into the field to perform this measurement, and it means more real-time grid management (e.g., for phase load balancing). Meter and network manufacturer Sensus' Gen 6 meter, combined with its point-to-multipoint network and phase detection solution, has been used in Arizona[24] to reduce the impact from large demands for energy as a result of increased tourists staying through the winter months.

AMI 2.0 helps "future-proof" the meter. Unlike AMI 1.0, in which memory was limited and over-the-air updates were limited to firmware, AMI 2.0 meters are like smartphones that can have new apps pushed to them as new requirements develop. Requirements that have not been incubated yet can be identified and developed into new software that can be distributed from the utility's operations center and run as needed. Newer residential meters are simplifying solar installations by combining the capabilities of a standard meter and a net meter into a single unit. In addition, Landis+Gyr is currently piloting a meter with the ability to sub-meter and control DER devices such as EV chargers and solar inverters to improve visibility, safety, and control.

Deloitte's research suggests electric utilities have positioned themselves at the forefront of decarbonization[25] activities needed to reduce greenhouse gas (GHG) emissions, and AMI 2.0 has a role to play to achieve decarbonization goals. As automobiles currently account for 27% of GHG emissions,[26] reducing truck rolls to either perform routine services at a residence, or to restore power, is critical.

Utilities in the first-wave AMI deployment (pre-2010) will need to replace their AMI 1.0 meters before they reach end of life or risk an increase in meter readers and service trucks, which would increase carbon emissions, to service a high volume of meters. Another important action utilities can take to reduce carbon emissions related to AMI 2.0 is to help consumers move to electric vehicles to reduce GHG. To do so, electric utilities need to be able to support a significant increase in the number of EVs and EV chargers needed to make a difference in reducing the carbon footprint. According to EVAdoption,[27] the number of EVs in the United States is expected to rise from 850,000 today to more than 4.7 million by 2030. This opens an opportunity for electric utilities to provide charging as a service by which the utility could install and rent smart chargers for their customers and offer reduced prices to EV owners who allow the utility to have some control over when the vehicle can be charged. Having AMI 2.0 smart meters will give electric utilities the data they need to understand the real load on the grid and plan for and operate the distribution of energy safely under these evolving demands.

Conclusion

Utilities that were early adopters of AMI were able to obtain the operational benefits of meters that collected interval reads, transmitted power-quality information, and remotely switched power on and off. The AMI residential customers that received the most benefit were those that acted proactively with their utility to sign up for programs that allowed them to track consumption and shift energy usage to off-peak times. Since the pre-2010 early days of AMI, meter technologies and capabilities have advanced, allowing meters to deliver more personalized value to the consumer and provide increased benefits to the utility at a time when utilities are seeing tremendous growth in distributed energy sources such as solar panels putting energy back onto the grid and electric vehicles drawing significant energy off the grid. Any electric utility that deployed AMI prior to 2010 or which has not yet deployed AMI should be in the planning phases to replace their aging AMI assets today. Other utilities that deployed AMI after 2010 and have decarbonization goals, or are facing potential grid resiliency issues because of climate conditions, or are expecting a rise in distributed energy resources (electrical vehicles, solar panels, home batteries) should also be investigating and planning for the next generation of AMI technologies.

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