AMI for Improving Distribution Operations
A GTM Research Whitepaper
# TABLE OF CONTENTS

1 Executive Summary 3

2 Introduction 4

3 The Case for Improving Distribution Operations 5
   3.1 Outage Costs 5
   3.2 Penalties and Incentives 5
   3.3 Assessing the Present, Preparing For the Future 5

4 AMI and Analytics: Enabling Service-Level Benchmarking 6
   4.1 The Service-Level Agreement (SLA) 6
   4.2 Establishing Baseline Performance 6

5 The SLA: A Framework for Improving Distribution Operations 8
   Improving Outage Management 8
   Justifying Additional Investment 9
   Volt/VAR Management 9
   Reactive Power Management 10
   Conservation Voltage Reduction (CVR) 10
   Updating the Connectivity Model 10
   Decreasing Line Losses 11
   Improving Capacity Planning 11
   Targeted Demand Response 12
   Enhancing Asset Management 12

6 The AMI Maturity Model: A Roadmap for Improvement 13
1 EXECUTIVE SUMMARY

Smart meters have become key assets at the edge of the distribution grid, capable of recording both historical and real-time data, while in turn enabling utilities to analyze the state of the grid in new ways in order to establish baseline performance, improve existing distribution operations and aid in long-term planning. While the billing-related cost savings of smart meters and advanced metering infrastructure are already well documented, some utilities are just beginning to act upon the wealth of information provided by smart meters in order to operate the distribution grid more reliably, efficiently and cost-effectively.

The benefits of these types of targeted and data driven improvements in distribution operations transcend all classes, geographies and underlying market conditions in the territories in which utilities conduct business. Circumstances which warrant examining and improving distribution operations include energy theft in countries such as Brazil and India; improved reliability in North America; the ability to absorb more renewable and locally generated energy in Europe; and energy conservation in resource-scarce countries such as Japan, as well as universally desirable increases in efficiency, decreases in overall system losses and decreased operating costs. Moreover, the data provided by smart meters presents opportunities for continuous improvement in all of the aforementioned areas.
2 INTRODUCTION

The electric grid consists of both high-voltage transmission networks and medium- and low-voltage distribution lines which deliver power to end users. Most utilities historically have had limited insight into the condition of the distribution grid at the local level, despite this being where a majority of outages originate. In the absence of distribution-line monitoring devices, grid operators have relied upon static models for state estimation. In reality, connectivity and consumption models must be refreshed when circuits are rebalanced after outages, equipment is installed or reconfigured, and/or new loads such as rooftop photovoltaic systems and electric vehicles are added to the system. While traditional models can aid in predicting which service areas are most likely to be impacted by outages, outage notification and restoration is dependent upon imperfect information that is typically provided by customers. Similarly, critical utility operations such as capacity planning and asset management rely upon probability and estimation based on one-size-fits-all customer and class load profiles.

However, these protocols are rapidly changing with the implementation of smart meters. The consumption and power quality data recorded by smart meters provide actionable information that can be used to continuously validate, correct, and improve models, as well as to optimize additional investment in targeted reliability measures.
3 THE CASE FOR IMPROVING DISTRIBUTION OPERATIONS

3.1 Outage Costs

As the global economy has become increasingly reliant upon technology, power outages have evolved from minor inconveniences to major economic and societal disruptions. In the United States alone, outages cost more than $80 billion annually,1 while substandard power quality can cost an additional $15 billion to $24 billion per year.2 In addition, outage costs are not linearly related to outage duration – Lawrence Berkeley Laboratory estimates that 67% of all outage-related economic losses result from momentary interruptions. Apart from monetary losses, outages can endanger the well-being of customers who depend on electric heating systems and life-sustaining medical devices.

3.2 Penalties and Incentives

While the detrimental effects of outages have become more pronounced as society has become more dependent upon technology, so too have the penalties levied against utilities for poor reliability. In the United States, regulators have both denied and significantly diminished allowed returns for utilities in recent rate cases due to poor historical performance. In the state of Illinois, legislators recently implemented performance-based penalties tied to system performance metrics, including system average interruption frequency index (SAIFI) and customer average interruption duration index (CAIDI). Similarly, New York’s largest investor-owned utility, Con Edison, was recently ordered by the state public service commission to disburse $5 million (of a maximum penalty of $112 million) to ratepayers for failing to meet reliability standards.

Greater accountability is not a trend unique to the United States. In Sweden, for example, the Swedish Electricity Act mandates that utilities must compensate end-users based on outage duration – up to a maximum of 300% of annual network costs. However, while there is clearly external pressure to improve reliability, improving distribution operations can be lucrative in and of itself. For example, Duke Energy Ohio anticipates saving over $115 million over the lifetime of its AMI deployment by leveraging the system for integrated voltage control.

3.3 Assessing the Present, Preparing For the Future

With the emphasis placed on greater accountability, utilities will be required to implement measures to deliver power both more reliably and more efficiently in order to improve historical performance, as well as to meet the challenges that the evolution of the electrical grid has already begun to present. It is critical for utilities to understand not only the current level of service being provided and overall level of smart grid maturity, but also opportunities for improvement. The benchmarking capabilities of smart meters and an integrated analytics platform, allows utilities to answer crucial questions of “Where are we now?” “Where are we going?” “How do we get there?” and “Have we made it?” as they navigate the road to improving distribution operations.

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4 AMI AND ANALYTICS: ENABLING SERVICE-LEVEL BENCHMARKING

4.1 The Service-Level Agreement (SLA)

Like any exchange between consumers and service providers, there is a “contract” that defines the level of service expected by the customer and committed by the supplier. While in many cases these commitments are defined by regulators, a growing number of utilities are considering enhanced service level guarantees and service options. Regardless of whether the service levels are mandated or voluntary, it is becoming clear that best practices in distribution operations include the concept of a service-level agreement. A typical service-level agreement for an electric utility must contain three key elements:

1. Service Availability: The ability to ensure that power is supplied with minimal interruption, and, if power is lost, that it is restored expeditiously.

2. Service Voltage: The ability to ensure that line voltage is within specifications (regulated range, including reactive power).

3. Service Capacity: The ability to deliver the capacity contracted by the customer.

4.2 Establishing Baseline Performance

A critical first step in ensuring that these service obligations are met is establishing baseline performance. Prior to the widespread deployment of smart meters, conducting system audits of this nature were costly, resource-intensive and impractical at the customer level. Given these limitations, models were largely based on class and customer averages, and typically were not indicative of true system performance.
Today, smart meters represent a key demarcation between the customer and grid, serving as a point at which the SLA can be easily and frequently measured with a high degree of granularity. However, many utilities are inundated with data and remain uncertain as to how best to utilize this information, outside of improving billing operations.

**INTEGRATED, BUT DISCRETE ANALYTICS**

Initial deployments of smart meters were driven primarily by the desire to improve the meter-to-cash process and were focused on decreasing operating expenses via reducing manual meter reads, decreasing truck rolls and eliminating estimated bills, with minimal integration of other utility IT systems and/or analytics platforms. Therefore, it is critical that analytics-intensive applications that analyze operational and event-based data do not compromise or compete with primary billing functions.

To achieve this, data is passed from the AMI head-end system to the meter data application platform (MDAP), which serves as the ‘system of record’ for all metered energy consumption and service delivery data. Using an event-based architecture, data is streamed to a discrete analytics-oriented database where it can be leveraged for numerous applications, including ad-hoc reporting and data mining, packaged analytic-intensive applications (e.g., load aggregation and non-technical loss assessment), in addition to being available to federated data analytics or an enterprise warehouse system. The separation between the meter data application platform operational database and the analytics database allows near-real-time information to be used selectively or in aggregate, resulting in streamlined and timely analysis, without compromising primary billing operations.

The key to extracting additional value from the data-logging capabilities of smart meters is identifying which information can serve as ‘actionable’ intelligence. When coupled with a meter data application platform and flexible, discrete, analytics platform, smart meters can serve as a means of ‘continuous commissioning’ of the grid and be utilized under both normal operating conditions, and manage-by-exception scenarios (e.g., voltage alarms, power quality fluctuations). The current generation of electronic meters can measure, record and report these values and present the opportunity not only to baseline current performance, but also to trend and report results of improvement efforts. This operational data can be routinely aggregated by substation, circuit, and transformer, as well as by customer class, in order to proactively identify problematic areas, monitor improvements, and more easily quantify return on investment.
5 THE SLA: A FRAMEWORK FOR IMPROVING DISTRIBUTION OPERATIONS

Within the three components of the service-level agreement, there are ten key applications in which smart meter data can enable improvements, with improved outage management generally considered to have the most immediately realizable benefits.

**Figure 5-1: Applications of a Typical Service-level Agreement**

1. **Service Availability**
   
   In our digital world, where everyday tasks have become increasingly automated, outage identification and restoration is still a painstakingly slow and manual process. Utilities remain largely dependent upon customer call-ins to identify outages, as well as to confirm when power has been restored. Additionally, field crews can easily overlook ‘nested’ outages, unintentionally leaving customers without power.

   **Improving Outage Management**
   
   ‘Last-gasp’ messages transmitted by smart meters can be leveraged to rapidly locate, identify and assess the severity of outages, as well as to help field crews restore service as quickly as possible. Smart meters can also validate that power has been restored, helping to ensure that service is returned to all customers and allowing utility field crews to quickly move to other affected areas once they are certain that restoration has been completed in that area. Furthermore, outage reports from smart meters are more comprehensive and timelier than customer calls and with proper handling and integration can help operators prioritize restoration work and ensure that repair crews are dispatched in merit order. These real-time and near-real-time attributes of a mature AMI and analytics platform enable targeted workforce management that can improve electric service availability and decrease outage-related operating expenses.
To leverage last-gasp messages and event-driven alarms, data must be efficiently integrated with other utility systems, especially the outage management system (OMS), and the distribution management system (DMS). However, integration is not simply sending every message from a meter to an OMS. Outage messages may overwhelm an OMS, and the OMS doesn’t track where a meter is installed relative to geography and other components of the grid. Additionally, messages may be stale or redundant, and outages may be caused by scheduled field work or switching. Proper integration of this capability with an OMS requires pre-processing of meter-generated messages to create valid and confirmed events to be relayed to the outage management system.

In addition to sustained outages, customer SLAs are impacted by momentary interruptions that are often not reported or detected by the utility. However, these momentary outages are registered and recorded by smart meters. This momentary data is used to support critical analysis of distribution line integrity and power quality issues. Furthermore, these analyses can prompt proactive operations, such as targeted tree-trimming and protective device adjustments to reduce momentary interruptions and improve power quality.

**Justifying Additional Investment**

Using critical outage and momentary interruption information provided by smart meters, distribution operators have a clear picture of the customer service levels they are providing and how they are performing against the critical SLA of power availability. Using this as a baseline allows the distribution operator to target investments in additional automation to improve performance through implementing devices such as automated reclosers and switching, as well as additional sensing and monitoring such as fault current indicators (FCIs). Additionally, the existing AMI field area network can be used to verify that these secondary devices are functioning properly, as well as providing the intended benefits.

**2. Service Voltage Commitment and Voltage Management**

**Volt/VAR Management**

In North America, standards mandate that line voltage for end consumers must remain between 114 volts and 126 volts in order to provide an acceptable level of service and prevent damage to consumer devices. As electricity travels from the substation to the end user, voltage naturally drops due to resistance in distribution lines and losses in transformers. Customer loads, especially large motors, can draw power out of phase with the supply, creating ‘reactive loads.’ To compensate for this, capacitor banks are installed along distribution lines and voltage regulators are operated at substations to regulate voltage and reactive power so that customers near the substation receive power at well above 120 volts and others farther from the substation are still above the minimum 114 volts. This approach to voltage management has relied upon mathematical models in lieu of a closed loop, sensor-based system, requiring more conservative implementation with wider voltage tolerances, ultimately resulting in suboptimal efficiency.

Conversely, smart meters enable routine measurement and verification of voltage at customer premises, allowing voltage regulators and capacitor operations to be optimized to close the loop around voltage management. Today, smart meters are capable of logging voltage levels, sending
“report by exception” voltage alarms, and with analytics and event-management solutions, these new telemetry sources can be used to maintain system voltages for all customers closer to the nominal 120-volt service level. This narrowing of the range of distribution line voltage helps to reduce system losses, as well as to meet the voltage conditions specified by the SLA.

Reactive Power Management

In most AC circuits, current and voltage rarely remain in phase, in turn generating a phenomenon known as reactive power (measured in Volt-ampere reactive or VAR). Excess reactive power flows can lead to decreased efficiency in transmission and distribution lines, as well as an overall decrease in system performance, impacting system voltage. By measuring reactive power, smart meters can identify customer loads that generate the most reactive power flow and those circuits which may benefit from the deployment of grid assets used in the management of reactive power such as capacitor banks. While the implementation of additional capacitor banks can significantly reduce line losses when functioning properly, malfunctioning timers and blown fuses reduce the effectiveness of these devices, often unbeknownst to grid operators. Reactive power measurements recorded by smart meters can be used to verify that these assets are both functioning properly and achieving the intended benefits in supporting system voltage.

Conservation Voltage Reduction (CVR)

If the distribution network voltage is well managed and the SLA of service voltage is met, then there is an opportunity to proactively reduce service voltages to accommodate temporary supply constraints caused by periods of peak demand. Virginia utility Dominion Power has been utilizing its AMI system to operate a CVR program since early 2010, resulting in demand reductions of approximately 3%, which are expected to save more than $1 billion over the next twenty years. Additionally, unlike traditional demand-side management programs, the demand reductions achieved through CVR are not dependent upon consumer behavior. Even in service territories without formal decoupling and revenue recovery mechanisms, strategically implemented CVR during periods of peak demand can result in savings that in many cases outweigh the costs of lost revenue from the delivery of fewer megawatt-hours of electricity.

3. Service Capacity

Utility distribution operators today have a limited set of tools with which to ensure the delivery of adequate capacity to the consumer. Most of these tools rely on historical and average customer load profiles, with limited information available about actual power flows in their network. Operating models of the distribution network generally contain connectivity errors due to limited data capturing and poor documentation of changes made on-site during emergency repairs or network upgrades. The data collected by smart meters presents several opportunities to improve the distribution operator’s ability to ensure the stated capacity is supplied to the customer.

Updating the Connectivity Model

The grid connectivity model is a critical foundation for all system planning and capacity modeling. Real-time operational systems (EMS, DMS) use these models and sophisticated state-estimations to manage power flows in the system and determine where capacity constraints exist. However, the
'last mile' of these models is often missing or incorrect, and customer connections to circuit phases, as well as transformer connections to three phase feeders, may not be fully documented or up-to-date. While data from smart meters cannot itself correct these errors, the information provided can identify where errors exist. Load models from state estimations and planning power-flow calculations can be compared to load aggregations from smart meters, and large discrepancies can justify further investigation. Some utilities are leveraging smart meter data to perform complete system surveys to correct connectivity errors. Additionally, outage and momentary data can be correlated with protective devices and connections to further reconcile discrepancies in the connectivity model. Frequent analysis of the data provided by smart meters allows these activities to be targeted at areas prone to recurrent issues.

Decreasing Line Losses

As electricity travels from generators to end-users, energy is lost due both to the physical properties of the grid (technical line losses), as well as by way of theft, non-payment and other factors external to the grid (non-technical losses). In countries such as Brazil and India, non-technical losses can account for up to 40% of the energy produced in certain regions. Operational and power quality information recorded by smart meters can be aggregated in order to identify and assess load anomalies on specific circuits, transformers, and other key distribution assets. This information can be used to cleanse and validate the connectivity model, as well as to identify faulty, improperly sized, and/or overloaded lines and transformers. For non-technical line losses, meter data can regularly be compared to historical consumption patterns in order to identify and curtail energy theft.

Improving Capacity Planning

The electrical grid was designed to accommodate the one-way flow of power from large, centralized generating plants. However, capacity planning must evolve to take into consideration intermittent, distributed energy resources at the edge of the grid and the two-way flow of power.

Traditional load planning and forecasting is based on customer class averages. In reality, each customer consumes electricity at different times of the day, in varying quantities. Smart meters enable the generation of granular, locationally and temporally specific forecasts reflective of true local peak loads, rather than estimates based on system coincident peaks and class-load averages. Using aggregations of individual metered interval data, system planners have access to actual local load aggregations with hourly or higher resolution. Analyzing actual loads can identify local capacity constraints both in delivering energy and in receiving energy from distributed energy sources such as rooftop photovoltaic (PV) systems.

In this sense, smart meters serve as critical sensors capable of identifying unbalanced and overloaded circuits, which are increasingly caused by conditions such as high PV penetration and EV adoption. In conjunction with GIS and distribution planning and modeling tools, meter data can be overlaid onto a simple geospatial model and single-line diagram in order to visually identify areas of ‘clustering’ where these new challenges to the grid are most problematic. Additionally, new planning and modeling tools consider not only the steady-state loading during normal conditions but also the more complicated modeling around cold-load pick-up calculations and demand response events where PV, distributed energy resources and customer load controls may radically change the loads.
Targeted Demand Response

Smart meters provide information not only about how much energy is consumed, but also about when and where it is consumed. A flexible and discrete analytics platform can use this information to identify and prioritize peak load curtailment requirements. In turn, this can help maximize reliability by reducing peak usage, as well as save costs by deferring investment or procurement of generating capacity, without negatively impacting utility revenue and service. Additionally, the data provided by smart meters enables more detailed customer segmentation and surgical load curtailment, which can selectively exclude critical facilities such as hospitals, nursing homes, and police and fire stations from demand response events.

Enhancing Asset Management

Medium- and low-voltage distribution asset management historically has been a reactive process, characterized by scheduled maintenance on more critical and expensive assets and run-to-failure protocols on less essential devices. This delineation leaves most equipment on distribution lines neglected and operating well beyond its expected asset life. For instance, after a low-voltage secondary transformer is installed, maintenance crews may not inspect the device for up to 40 years (or until the asset fails). The implementation of a ubiquitous network of sensors (smart meters) allows grid operators to develop specific asset-loading information and predict life expectancy of the device, as well as allowing them to appropriately size conductors to meet future loading challenges. For transformers in particular, load models have historically been based on customer class profiles and monthly meter readings. Furthermore, given the time-skew of monthly meter reading processes, most transformer load modeling occurs in annual cycles. Therefore, not only are the local transformer loading models old and outdated, they are also based on averages that fail to represent the local peaks and load conditions on the device. Conversely, smart meters can provide timely (often daily) information on peak and average actual load conditions for nearly any transformer in the system.

Similarly, the peak and average actual loading on conductors historically has been estimated, and the benefits of calculating actual aggregated customer loads apply to assessment of conductors for sizing and replacements. System losses due to overloaded assets like distribution lines and transformers can be mitigated and asset upgrade investments can be targeted using actual, rather than estimated, load information generated from smart metering and data analytics.

Additionally, advanced telemetry devices can be deployed on critical assets more cost-effectively by utilizing the existing AMI field area network and capturing this new information in the meter data application platform enables integration with analytics as well as operational systems. Utilities employing these new telemetry sources, ranging from revenue metering to new telemetry devices, are using analytical tools to implement improved and structured asset management policies, which establish conditions for prioritizing proactive asset replacement, knowledge-based asset sizing for upgrades or new construction, and batching of workforce orders to replace or upgrade distribution assets in a manner that minimizes downtime and overtime costs.
6 THE AMI MATURITY MODEL: A ROADMAP FOR IMPROVEMENT

Smart meters provide an unprecedented level of insight into the operation of the distribution grid, and the SLA serves as a useful framework for helping utilities understand not only the level of service they are committed to providing customers currently, but also future opportunities for improvement as new challenges are encountered. For many utilities, the deployment of smart meters was a critical first step in realizing a more intelligent electric grid. However, utilities have been slow in moving past this early stage functionality (Stage I) and advanced smart grid applications are still considered to be outside the scope of business-as-usual.

Figure 6-1: The AMI Maturity Model

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Ultimately, utilities should not view the deployment of smart meters as a one-time, application-specific investment, but rather as an evolutionary process in which additional features can be selectively added and integrated to enable continued process improvement. However, increased AMI maturity remains largely dependent upon the implementation of an open platform that can enable the collection, prioritization, and analysis of increasingly larger quantities of information, as well as to unify and synchronize the operations of other key utility IT systems. In the absence of this type of keystone solution, the value extracted from advanced metering applications will remain limited.