Centers for Disease Control and Prevention
CDC 24/7: Saving Lives, Protecting People™

CDC report shows motor vehicle crash injuries are frequent and costly

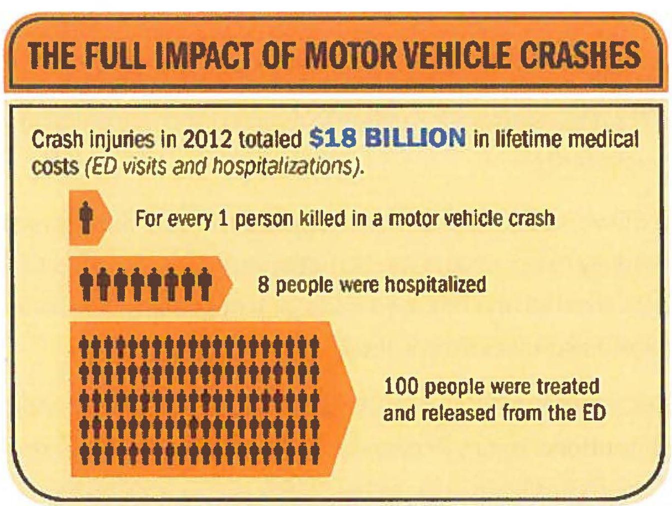
This website is archived for historical purposes and is no longer being maintained or updated.

Press Release

For Immediate Release: Tuesday, October 7, 2014
Contact: Media Relations (http://www.cdc.gov/media)
(404) 639-3286

CDC report shows motor vehicle crash injuries are frequent and costly

Americans spend more than 1 million days in the hospital each year from crash injuries



Full impact of motor vehicle crashes.
Entire Infographic

More than 2.5 million people went to the emergency department (ED) – and nearly 200,000 of them were hospitalized – because of motor vehicle crash injuries in 2012, according to the latest Vital Signs report by the Centers for Disease Control and Prevention.

Lifetime medical costs for these crash injuries totaled $18 billion. This includes approximately $8 billion for those who were treated in the ED and released and $10 billion for those who were hospitalized. Lifetime work lost because of 2012 crash injuries cost an estimated $33 billion.

"In 2012, nearly 7,000 people went to the emergency department every day due to car crash injuries," said CDC Principal Deputy Director Ileana Arias, Ph.D. "Motor vehicle crash injuries occur all too frequently and have health and economic costs for individuals, the health care system, and society. We need to do more to keep people safe and reduce crash injuries and medical costs."

Key findings include:

- On average, each crash-related ED visit costs about $3,300 and each hospitalization costs about $57,000 over a person's lifetime.
  - More than 75 percent of costs occur during the first 18 months following the crash injury.
- Teens and young adults (15-29 years old) are at especially high risk for motor vehicle crash injuries, accounting for nearly 1 million crash injuries in 2012 (38 percent of all crash injuries that year).
- One-third of adults older than 80 years old who were injured in car crashes were hospitalized – the highest of any age group.
- There were almost 400,000 fewer ED visits and 5,700 fewer hospitalizations from motor vehicle crash injuries in 2012 compared to 2002. This equals $1.7 billion in avoided lifetime medical costs and $2.3 billion in avoided work loss costs.

For this Vital Signs report, CDC analyzed ED visits due to crash injuries in 2012 using the National Electronic Injury Surveillance System-All Injury Program and the Nationwide Inpatient Sample. The number and rate of all crash injury ED visits, treated and released visits, and hospitalized visits were estimated, as were the associated number of hospitalized days and lifetime medical costs.

"Motor vehicle crashes and related injuries are preventable," said Gwen Bergen, PhD, MPH, MS, behavioral scientist in the Division of Unintentional Injury Prevention of the National Center for Injury Prevention and Control. "Although much has been done to help keep people safe on the road, no state has fully implemented all the interventions proven to increase the use of car seats, booster seats, and seat belts; reduce drinking and driving; and improve teen driver safety."

State officials can consider taking the following actions to prevent motor vehicle crashes and related injuries:

- Increasing seat belt use through primary enforcement seat belt laws that cover everyone in the car.
- Improving child passenger safety with restraint laws that require car seat or booster seat use for children age 8 and under or until 57 inches tall, the recommended height for proper seat belt fit.
- Reducing drinking and driving by using sobriety checkpoints and requiring ignition interlock use for people convicted of drinking and driving, starting with their first conviction.
- Improving teen driver safety through the use of comprehensive graduated driver licensing systems.
- Supporting traffic safety laws with media campaigns and visible police presence, such as sobriety checkpoints.
- Linking medical and crash data to better understand why crashes happen, the economic cost of those crashes, and how to prevent future crashes.

Released in conjunction with this month's Vital Signs is CDC's new interactive calculator, called the Motor Vehicle PICCS (Prioritizing Interventions and Cost Calculator for States). This tool will help state decision makers prioritize and select from a suite of 12 effective motor vehicle injury prevention interventions. It is designed to calculate the expected number of injuries prevented and lives saved at the state level, as well as the costs of implementation, while taking into account the state's available resources. A fact sheet for each intervention and a final report with methodologies and cost-effectiveness analyses are included. The Motor Vehicle PICCS is available online at: http://www.cdc.gov/motorvehiclesafety/calculator.

CDC's Injury Center works to protect the safety of everyone, every day. For more information about motor vehicle safety, please visit www.cdc.gov/motorvehiclesafety.

Vital Signs is a CDC report that appears on the first Tuesday of the month as part of the CDC journal Morbidity and Mortality Weekly Report, or MMWR. The report provides the latest data and information on key health indicators. These are cancer prevention, obesity, tobacco use, motor vehicle passenger safety, prescription drug overdose, HIV/AIDS, alcohol use, health care-associated infections, cardiovascular health, teen pregnancy, food safety and viral hepatitis.

###

U.S. DEPARTMENT OF HEALTH AND HUMAN SERVICES (http://www.hhs.gov/)

Connect with CDC Media

Subscribe to Media RSS Feeds

Subscribe to CDC Media e-mail (https://service.govdelivery.com/service/subscribe.html?code=USCDC_1_3&login=&origin=https://www.cdc.gov/media/index.html)

Syndicate Media on Your Site (http://tools.cdc.gov/syndication/)

CDC Quick Links

CDC In The News (https://www.cdc.gov/media/archives.htm)

Data & Statistics

Freedom of Information Act Office

Public Health Image Library (PHIL) (http://phil.cdc.gov)

CDC 24/7 Saving Lives. Protecting People. LEARN MORE ABOUT HOW CDC WORKS FOR YOU.

Page last reviewed: October 7, 2014 (archived document)
Content source: Centers for Disease Control and Prevention (/)

ELECTRIC POWER RESEARCH INSTITUTE

Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

1016049

Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

Technical Update, December 2008

EPRI Project Manager
Charles Perry

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Reilly Associates

Electric Power Research Institute (EPRI)

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

CITATIONS

This report was prepared by

Reilly Associates
P.O. Box 838
Red Bank, NJ 07701

Principal Investigator
J. Reilly

Electric Power Research Institute (EPRI)
942 Corridor Park Blvd.
Knoxville, TN 37932

Principal Investigator
C. Perry

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In the Future. EPRI, Palo Alto, CA: 2008. 1016049.

PRODUCT DESCRIPTION

Revenue security is a major concern for utilities. Theft of electric service in the United States is widespread. In 2006, the revenue estimate for non-technical losses was $6.5 billion. Non-technical losses are associated with unidentified and uncollected revenue from pilferage, tampering with meters, defective meters, and errors in meter reading. In this report, revenue security describes the use of advanced metering infrastructure (AMI) technology to minimize non-technical losses.

Results and Findings

The report defines revenue security as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. The report distinguishes between revenue losses caused by technical and non-technical factors, with a primary focus on the latter. Integrated with meter data management system (MDMS) technology—software that accepts, stores, and forwards AMI-collected data to utility systems such as billing—AMI significantly improves a utility's ability to monitor customers' electric meters and detect both intentional electricity bypasses and unintentional errors (for example, billing and customer service problems encountered by traditional manual meter-reading operations). The report describes AMI technologies in detail, from enabling hardware and software to transitioning from traditional systems to installation and implementation. The transition from meter reader to meter revenue protection agent also is discussed. A case study concludes the report by describing how PPL Electric Utilities of Pennsylvania successfully deployed and implemented AMR/AMI throughout its entire service territory (1,353,024 meters as of 2006).

Challenges and Objective(s)

Revenue security involves securing revenue that is due distribution utilities from delivery of electricity to end-users. It includes both reducing losses and collecting revenue associated with the electricity delivered. Non-technical distribution losses occur at the point of delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is delivered, measured, and billed. This is the challenge to revenue security.

Applications, Values, and Use

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. After AMI installation, utilities may uncover a substantial number of previously unknown sources of diversion. By reading meters frequently, AMI also identifies bad meters more quickly and reduces the need for estimating unmetered energy use. AMI's improved meter-reading accuracy also results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.

EPRI Perspective

AMI systems provide new and innovative tools for revenue assurance. With comprehensive AMI/MDMS and vigorous meter revenue protection programs, AMI will have a positive impact on minimizing non-technical losses due to theft. In areas other than theft, AMI offers additional advantages, such as using MDMS features in customer service to respond more quickly and accurately to high-bill inquiries.

Approach

The project team gathered information for this report from a variety of sources, including government surveys, industry reports, Internet searches, utilities, and vendors. When determining the impact of non-technical losses on revenue, the team examined aggregate measurements of revenue and distribution losses from reliable government statistical sources and applied ratios from various industry surveys and reports.

Keywords

Advanced metering infrastructure
Revenue assurance
Meter data management systems
Non-technical losses
Meter tampering
Electricity theft

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
CHAPTER 1

Revenue Security

Revenue security may be viewed as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. It includes both the reduction of losses and the collection of the revenue that are associated with the electricity delivered. The activities related to revenue security are oftentimes called "revenue protection" or, more recently, "revenue assurance."[1]

Utility revenue is a function of electricity delivered to end-users (kWh) and the billing rate ($/kWh).

This is expressed in the following formula:

$$R = E_d * r$$

Where:

R = Revenue ($)
E_d = Energy delivered (kWh)
r = rate ($/kWh)

The electricity delivered to end-users is generation minus losses in generation, transmission, and distribution. Distribution losses are divided into two components, technical and non-technical.

This is expressed in the following formula:

$$G - (L_g + L_t + L_d + L_n) = E_d$$

Where:

G = Gross generation
L_g = Generation losses
L_t = Technical losses – transmission
L_d = Technical losses – distribution
L_n = Non-technical losses
E_d = Energy delivered

Transmission losses and technical distribution losses relate to the physical characteristics and functioning of the electrical system itself. Non-technical distribution losses occur at the point of

[1] Revenue assurance includes theft detection and follow-up, metering malfunctions, billing errors and the like, consumption on inactive accounts, and collections. These activities will be discussed at length in Chapter 2.

delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is *delivered, measured, and billed*. This is the challenge to revenue security.

Distribution Losses

Losses in power distribution systems have two components: technical and non-technical.

Technical Losses

Technical loss is the component of distribution system losses that is inherent in the electrical equipment, devices, and conductors used in the physical delivery of electric energy.

Technical loss is intrinsic to electrical systems, as all electrical devices have some resistance and the flow of currents will cause a power loss (I2R loss). Integration of this power loss over time, i.e. _ I2R.dt, is the energy loss. Every element in a power system (a line or a transformer) offers resistance to power flow and, thus, consumes some energy. The cumulative energy consumed by all these elements is classified as "technical loss." Technical losses are due to energy dissipated in the conductors and equipment used for transmission, transformation, sub-transmission, and power distribution. These occur at many places in a distribution system—for example, in lines, mid-span joints and terminations transformers, and service cables and connections.

Technical losses vary greatly in terms of network configuration, generator locations and outputs, and customer locations and demands. In particular, losses during heavy loading periods or on heavily loaded lines are often much higher than those that occur in average or light loading conditions. This is because a quadratic relationship between losses and line flows can be assumed for most devices of power delivery systems. It is not possible to altogether eliminate such losses, which are inherent in a system; they can, however, be reduced to some extent.

Technical losses include the load and no-load (or fixed) losses in the following:

- Sub-transmission lines
- Substation power transformers
- Primary distribution lines
- Voltage regulators
- Capacitors
- Reactors
- Distribution transformers
- Secondary distribution lines
- Service drops
- All other electrical equipment necessary for distribution system operations

Technical losses also include the electric energy dissipated by the electrical burdens of the metering equipment such as potential and current coils and instrument transformers.

Technical losses can be calculated based on the natural properties of components in the power system: resistance, reactance, capacitance, voltage, current, and power.

Non-Technical Losses

Non-technical loss is the component of distribution system losses that is not related to the physical characteristics and functions of the electrical system. Rather, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These are conditions that the technical losses computation fails to take into account. Such losses are caused primarily by human error, whether intentional or not. Non-technical losses are associated with unidentified and uncollected revenue arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of the utilities due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses.

Non-technical losses also can be viewed as undetected load—customers that utilities do not know exist. When an undetected load is attached to the system, the actual losses increase while the losses expected by the utilities will remain the same. The increased losses will show on the utility's accounts, and the costs will be passed along to the customers as transmission and distribution charges.

Reasons for non-technical (or commercial) losses:

- Non-performing and under-performing meters
- Incorrect application of multiplying factors
- Defects in current transformer (CT) and potential transformer (PT) circuitry
- Non-reading of meters
- Pilferage by manipulating or bypassing of meters
- Theft by direct tapping and so on

All these losses are due to non-metering or under-metering of actual consumption. Non-technical losses occur at many places in a distribution system. These are shown in the following insert.[2]

[2] *Best Practices in Distribution Loss Reduction*, DRUM Program, Power Systems Training Institute, Bangalore – 560070. December 2007. The DRUM (Distribution Reform, Upgrades and Management) project is a series of training and capacity building programs in distribution. The broad objective of the training program is to share relevant regional and international experience in the management of distribution business. The program will cover all the important aspects of the distribution business ranging from regulatory matters such as approaches to tariff setting, open access, and reforms to issues of concern to utilities such as quality of service, information management, and energy efficiency. It is supported by USAID and the Ministry of Power, India.

Losses Due to Non-Technical Reasons	
Loss at consumer end meters	Poor accuracy of meters
	Large errors in CTs/PTs
	Voltage drop in PT cables
	Loose connections in PT wire terminations
	Overburdened CT
Tampering/bypass of meters	Where meters without tamper-proof/temper-deterrent/tamper-evident meters are used
	Poor quality sealing of meters
	Lack of seal issue, seal monitoring and management system
	Shabby installation of meters and metering systems
	Exposed CTs/PTs where such devices are not properly securitized
Pilferage of energy	From overhead "bare" conductors
	From open junction boxes (in cabled systems)
	Exposed connections/joints in service cables
	Bypassing the neutral wires in meters
Energy accounting system	Lack of proper instrumentation (metering) in feeders and detector tubes (DTs) for carrying out energy audits
	Not using meters with appropriate data logging features in feeder and DT meters
	Lack of a system for carrying out regular (monthly) energy accounting to monitor losses
	Errors in sending end meters, CTs and PTs
	Loose connections in PT wires (which result in low voltage at feeder meter terminals)
	Energy accounting errors (by not following a scientific method for energy audits)
Errors in meter reading	Avoiding meter reading due to several causes such as house locked and meter not traceable
	Manual (unintentional errors) in meter reading
	Intentional errors in meter reading (collusion by meter readers)
	Coffee shop reading
	Data punching errors (at MRI and by meter readers)
	Data punching errors by data entry operators
	Lack of validation checks
	Lack of management summaries and exception reports on meter reading
Errors in bills	Errors in raising the correct bill
	Manipulation/changes made in meter reading at billing centers—lack of a system to assure integrity in data
	Lack of a system to ensure bills are delivered
Receipt of payment	Lack of a system to trace defaulters, including regular defaulters
	Lack of a system for timely disconnection
	Care to be taken for reliable disconnection of supply (where to disconnect)

Factors Contributing to Non-Technical Losses

Theft and Non-payment

The most prominent forms of non-technical loss are electricity theft and non-payment. Electricity theft is defined as a deliberate attempt by a person to reduce or eliminate the amount of money he or she will owe the utility for electric energy. This could range from creating false consumption information used in billings by tampering with the customer's meter to making unauthorized connections to the power grid.

Power theft by existing customers is the predominant cause of loss of revenue to the electrical utilities. Almost all customer classes are involved in this: residential, commercial, industrial, and public entities. The consequences of power theft are manifest in many areas of an electric distribution company's business, including transformer failures, equipment breakdowns, poor revenue collection, financial losses, lower credit rating for the utility, increased technical losses, and the corroded integrity of employees.

Theft of power is committed by bypassing the meter or meter tampering. Totally bypassing the meter is done by directly tapping into the distribution line; partial or full load is then fed directly.

There are numerous methods of meter tampering. New methods are constantly evolving and detection of tampering is a continuous challenge for distribution utilities.

Theft can be active or passive. A customer may actively engage in illegal tampering to avoid the registration on the meter, or a customer may take possession of a property, find that electricity and gas supplies are on, and therefore not apply for service, thus avoiding payment without tampering.

Direct tapping of power by non-customers is another source of theft that is widely prevalent in developing countries. This is mainly in domestic and agricultural categories. Geographical remoteness, mass basis for theft, poor law enforcement capability, and inaction on the part of utilities are helping this phenomenon.

Unmetered Connections

In some countries, certain customers are not metered and energy usage is estimated, instead of measured, with an energy meter. Usually, the loads involved are small and meter installation is economically impractical. Examples of this are street lights and cable television amplifiers. Unmetered connections pose problems in correctly estimating consumption, resulting in losses.

Defective Metering

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters.

Tampered, slow-running, stalled, or damaged meters cause substantial losses to distribution utilities. Electromechanical meters tend to get sluggish over a period of time, thus under-recording consumption. Stopped or damaged meters can be in place for many years, resulting in on-going losses.

Virtually all energy meters are subject to these kinds of errors and inaccuracies. Standards and protocols for accuracy audits, repairs, and replacement are required to ameliorate this situation.

Meter-Reading Errors

Meter-reading personnel occasionally make errors in recording their readings. For a good number of services the meter reader, at times, reports nil consumption without any comment. Sometimes the meter reader furnishes no readings or in some cases, furnishes table readings. Another error is the adoption of wrong multiplier factors.

Estimated Bills

Sometimes customer bills are prepared using estimates of consumption. The method of estimating customer consumption can distort recorded losses.

Late Billing and Poor Revenue Collection

Consumer complaints in the billing process can result from incorrect billing due to deficiencies in metering and data processing. Prolonged disputes, lack of consumer-friendly policies, connivance, incorrect identification of category, fictitious billing (of non-existent consumers), lack of reconciliation, and continuous provisional billing are causes for poor revenue collections and, thus, contribute to non-technical losses.

AMI WITH METER DATA MANAGEMENT (MDMS) CAN MITIGATE MANY OF THE FACTORS CONTRIBUTING TO NON-TECHNICAL LOSSES. THE ENABLING TECHNOLOGIES ARE DISCUSSED IN CHAPTERS 2 AND 3.

Non-Technical Loss Contribution to Technical Loss

It is often overlooked that non-technical losses can be a contributing factor to technical loss because of improper load management. Improper load management can lead to overloading of conductors and transformers in the system causing higher losses.

It can be argued that the distortion of load quantities caused by non-technical losses distorts computations for technical losses caused by existing loads, thereby rendering results ineffectual.[3] Energy diversion is a major aggravating factor in this situation.

Reducing non-technical losses may positively impact technical losses by mitigating congestion during periods of peak load when technical losses are particularly high.[4]

[3] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[4] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Measurement

Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.

Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty is obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable. For example, the framework for the business case adopted by the California Public Utilities Commission lists the reduction of non-technical losses as a benefit, but states that they are "not quantifiable, qualitative."[5]

Utilities rely on studies that are designed to calculate the magnitude, composition, and distribution of system losses based on annual aggregate metering information for energy purchases, energy sales, and system modeling methods. These studies are compared to industry and academic studies and models to establish the magnitude, composition, and distribution of losses.

Utilities have developed methods to measure non-technical losses primarily based on detection by manual meter readings and statistical analysis. These are often inaccurate. This is because the data rely heavily on the records of detected cases, rather than by actual measurement of the electrical power system. The reason that measurement or monitoring the power system is not the preferred method of measuring non-technical losses is because the infrastructure of the system, specifically the metering system, makes accurate and detailed loss determination impossible.[6] Measuring distribution line loses directly is not economic.[7]

The metering system is focused on the end-user, not on intermediary stages in the power distribution where technical and non-technical losses could be more accurately measured.

[5] *AMI Potential Benefits Categories Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure* (Draft Report), Moises Chavez, CPUC and Mike Messenger, CEC April 14, 2004. Easier identification of energy theft is categorized as "not quantifiable, qualitative"; meter accuracy, detection of meter failures, reduction in "idle usage," and billing accuracy are categorized as "short term."

[6] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[7] For the accurate measurement of technical losses on transmission and distribution systems, it would be necessary to install metering equipment at each voltage level of transmission and transformation.

The only real solution for identifying the non-technical loss component from transmission and distribution losses is through studies at the distribution utility level. Technical losses can be isolated at substations, and the differences with end-use consumption calculated from that point. Unfortunately, such studies are not conducted on a consistent or industrywide basis.

To get a magnitude measure of the impact of non-technical losses on revenue for purposes of this study, the approach is to examine aggregate measurements of revenue and "distribution" losses from reliable government statistical sources and apply ratios from various industry surveys and reports. The available data sources and their limitations must be taken into close account when considering the accuracy of the results. Economic loss levels tend to be system-specific. In the end, the resulting measure of revenue impact from non-technical losses is an order of magnitude estimation. Nonetheless, this approach is sufficient to demonstrate the value of each distribution utility taking its own measure of non-technical losses.

Data Sources

Data on revenue losses from non-technical losses are extremely difficult to come by. Data on non-technical losses are not collected by the Energy Information Administration (EIA) or industry associations. Data on the revenue attributable to those losses are not collected or estimated on an industrywide basis. Electric utilities consider these data confidential because they have implications for operating and financial performance.

Statistics on net generation and "transmission and distribution losses and unaccounted for," measured in kilowatt hours, are available in the Annual Energy Review.[8] Statistics on revenue from retail sales to ultimate customers and the supply and disposition of electricity are available from the Electric Power Annual.[9]

The most exhaustive study on revenue *metering* losses per se was made by EPRI in 2000.[10] The focus of this study was metering, anomalies, metering integrity, and theft rather than revenue and the full economic impact of non-technical losses.[11] This study was conducted before the benefits of automatic meter reading (AMR)/AMI had become noticeable. The study looks forward to that day though in its conclusion.

> "[Utilities have] a strong interest in quantifying these losses to assess their full effect on utility revenues and to provide a basis for mitigating technologies, such as Automatic

[8] Table 8.1 Electricity Overview, 1949-2006, Report No. DOE/EIA-0384(2006), Annual Energy Review 2006.

[9] Table 7.3 Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1995 through 2006 and Table ES2 Supply and Disposition of Electricity, 1995 through 2006, Electric Power Annual. October 22, 2007.

[10] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

[11] Ibid. For example, the definition of meter/billing errors states, "Included in this class are all scenarios involving personnel actions, where 'people errors' compromise metering integrity because of inexperience, inattention, lack of review, and lack of training. ... Meter mis-installation falls into this category."

Meter Reading (AMR), and the development of other future programs to reduce non-technical losses."[12]

The Office of Gas and Electricity Markets in the United Kingdom has conducted a number of studies evaluating the cost of distribution losses, including non-technical losses and also illegal abstractions (tampering with meters and illegal connections).[13]

Statistics

Aggregate statistics for transmission and distribution losses are presented in Table 1-1, along with revenue for the corresponding year. From this data the relationships and trends can be observed that offer insights into transmission and distribution losses, technical and non-technical, at a global level. As stated previously in the section on data sources, unfortunately these are the only statistical series that are available that offer an objective and consistent measure of the relevant variables at any level, from generation to end-user.

Table 1-1
Statistics

Key Statistics							
Year	Net Generation + Imports (million kWh)	T&D+UFE Losses (million kWh)	Ratio	Revenue from Retail Sales ($ million)	Revenue Loss T&D+UFE	Revenue Loss per million kWh	Rev Loss 2.0%
1996	3,487,684	230,617	6.6%	212,609	14,058	0.0610	4252
1997	3,535,204	224,380	6.3%	215,334	13,667	0.0609	4307
1998	3,659,809	221,056	6.0%	219,848	13,279	0.0601	4397
1999	3,738,025	240,086	6.4%	219,896	14,124	0.0588	4398
2000	3,850,697	243,511	6.3%	233,163	14,745	0.0606	4663
2001	3,775,144	201,564	5.3%	247,343	13,206	0.0655	4947
2002	3,895,231	247,785	6.4%	249,411	15,866	0.0640	4988
2003	3,913,575	227,573	5.8%	259,767	15,105	0.0664	5195
2004	4,004,765	265,918	6.6%	270,119	17,936	0.0674	5402
2005	4,099,950	264,479	6.5%	298,003	19,223	0.0727	5960
2006[P]	4,095,321	250,918	6.1%	326,506	20,005	0.0797	6530

[12] Ibid.

[13] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Transmission and Distribution Losses, Unaccounted for Energy

"Transmission and Distribution Losses and Unaccounted for" (T&D+UFE) is calculated as the sum of total net generation and imports minus total end use and exports.[14] Transmission and distribution system losses, including "unaccounted for energy," are generally defined as a percentage of the difference between total energy input to the network and sales to all customers.

These losses, as the global statistical measure of both technical and non-technical losses, are commonly compared to the aggregate of "Net Generation and Imports" to provide an indication of their magnitude and impact. This comparison is shown in Figure 1-1.

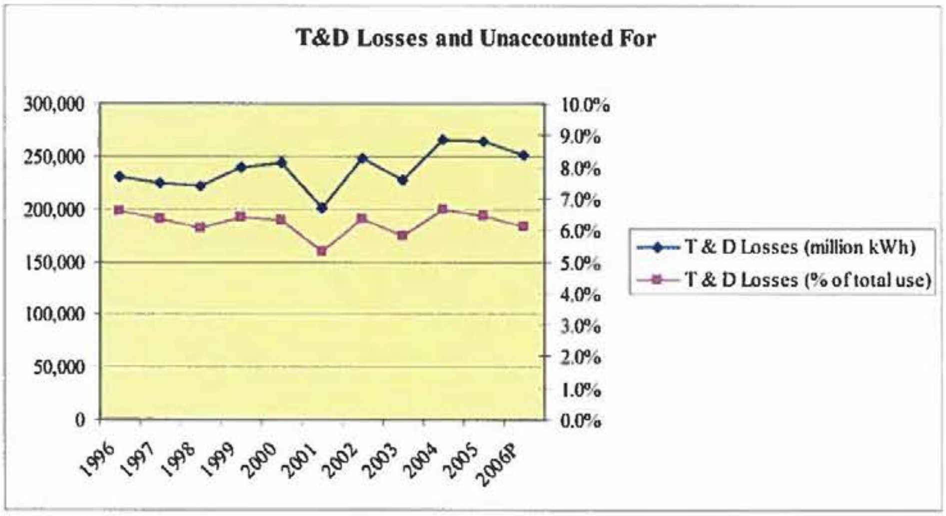


Figure 1-1
T&D Losses

Net Generation and Imports increased from 3.5 quadrillion kWh in 1996 to 4.1 quadrillion kWh in 2006, or 17.4%. Over that same time period, T&D+UFE increased from 230.6 billion kWh to 250.9 kWh, or 8.8%.

The average loss ratio of T&D+UFE to Net Generation and Imports was 6.2% over the eleven years from the beginning of 1996 to the end of 2006.

Revenue and Loss Trends

Revenue increased from $212.6 billion in 1996 to $326.5 billion in 2006, or 53.6%, while T&D+UFE increased only 8.8%. The trend lines for these increases are shown in Figure 1-2. For purposes of this study, it is significant to note that the trend for revenue increases is greater than T&D+UFE. This has a major impact on the importance of revenue loss from non-technical losses.

[14] *Annual Energy Review 2006*, Energy Information Administration, Department of Energy.

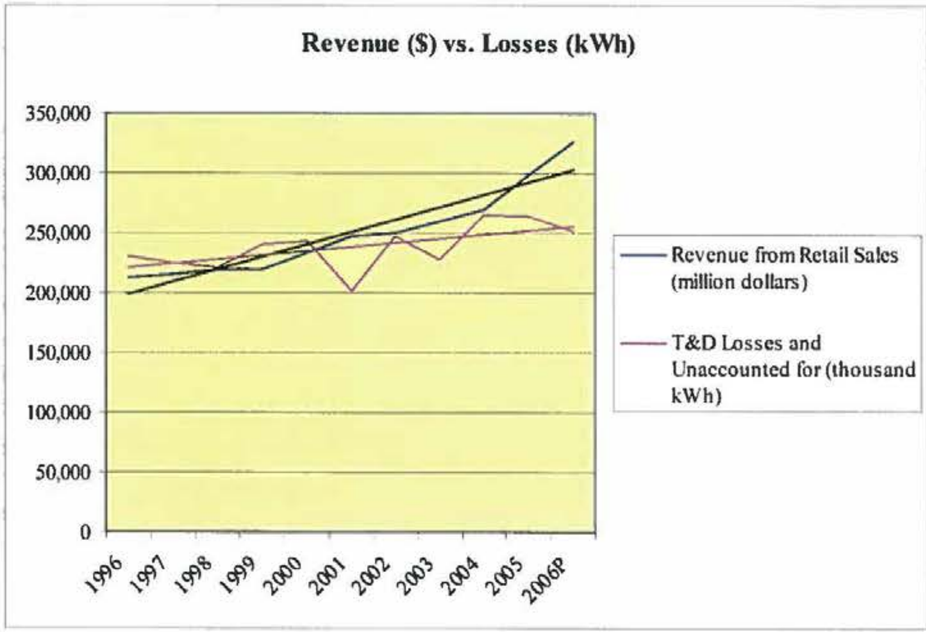


Figure 1-2
Revenue ($) vs. Losses (kWh)

Non-Technical Revenue Loss Estimate

It is difficult to ascertain the extent of technical and non-technical distribution losses separately. The reasons for the difficulty in estimating non-technical losses are discussed in the section on measurement above. For purposes of comparison, and again to get an order of magnitude view of the importance of non-technical revenue losses, a percentage of 2% is most often cited by experts in the industry (Figure 1-3). Applying a constant for the loss ratio, non-technical revenue losses parallel the global.

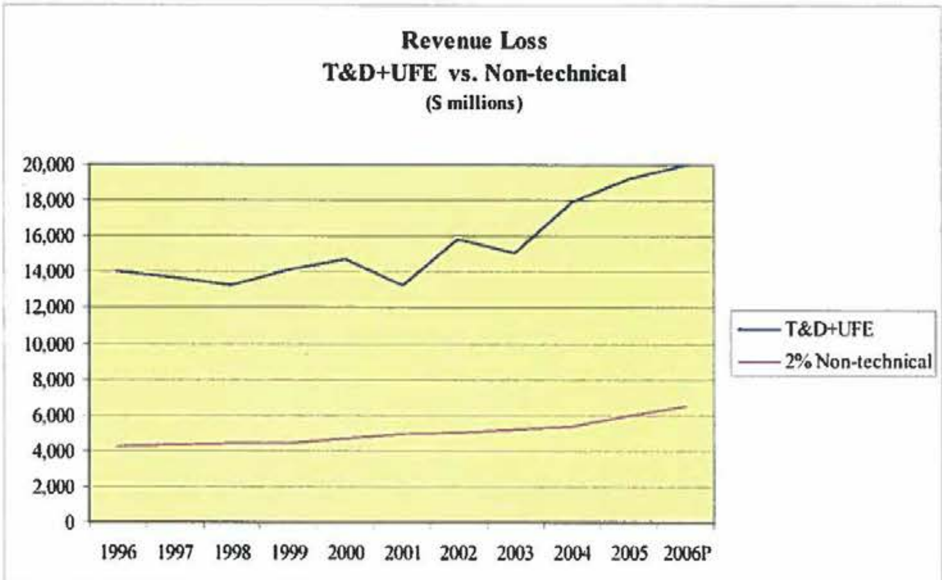


Figure 1-3
T&D+UFE vs. Non-Technical

Revenue Loss per kWh

With revenue rising at substantially higher rates than T&D+UDE losses, revenue loss per kWh is dramatically impacted. Each unit of technical and non-technical losses carries a higher revenue cost, just as each billed kWh carries a higher rate. The upward trend in revenue loss per kWh is shown in Figure 1-4.

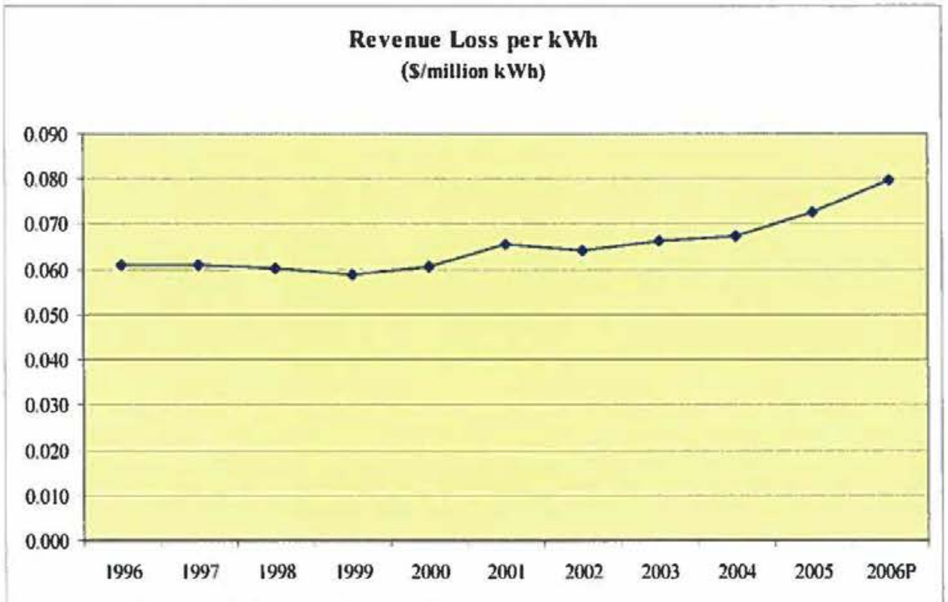


Figure 1-4
Revenue Loss per kWh

Whatever other inferences may be drawn from the data or conclusions reached about technical and non-technical losses, the fact remains that the revenue loss per kWh is increasing. The increases in these losses may be attributable to technical or non-technical components. However, it is most likely that they are more a function of revenue increases themselves. Energy costs have risen over the past decade, and this naturally is reflected in the value of units sold or units lost. Suffice to say, each kWh of reduction in non-technical loss brings the recovery of more revenue today than it did ten years ago.

Assuming that the ratio of non-technical losses to generation remains the same, the value of non-technical losses measured in $/kWh will be higher in terms of revenue. This should be taken into consideration when comparing the revenue losses in earlier studies (prior to 2002) to revenue losses today.

Non-technical revenue loss is greater today than ten years ago, placing greater importance on measures for their reduction.

Studies and Reports

Arizona Public Service Study

After reflecting on several reports and surveys from 1997 to 2000, the Revenue Protection Department at Arizona Public Service (APS) came to the conclusion that "available information regarding energy theft continued to be subjective, at best."[15]

The revenue protection team at Arizona Public Service Company decided to conduct a study of its own.

Two prior studies provided direction and information regarding the amount of various meter problems found in the field and could cite specific percentages. One study by United Energy determined that 2.16% of its meters were faulty. The other study, by the Canadian Electricity Association, found deviations (meter tampering), that would certainly lead to diversion, were definitely occurring across Canada. The average rate for these deviations (tamper rate) was 1.36%.[16]

The goal of the research study at APS was to determine the dollar amount of loss to theft and diversion.

The data in the APS study pointed to a much higher percentage loss among commercial accounts. Of the $7.9 million actual/probable loss, $5.1 million was attributed to commercial accounts. And, similar to the Canadian study, a large number of meter maintenance items were noted. Fully, 6.5% of the meters in the study had some type of maintenance problem.

The APS study concluded that 1.72% of meters were subjected to some form of tampering and that the associated revenue loss was $7.9 million, or 0.518% of revenues.

EPRI Study

The EPRI study on revenue metering loss assessment in 2001[17] concluded that there is "a widespread but unsubstantiated impression in the utility industry that revenue loss from all non-technical sources (excluding bad debt) is between 3% and 4% of utility revenue. Based on this work, we conclude it is far more likely that such losses are between 1% and 2%, and almost certainly are less than 3%. Of course, there will be exceptions in some utility territories. But today's well-managed utility with proactive revenue protection programs should fall below 2%.

[15] *Research Study Quantifies Energy Theft Losses*, John J. Culwell, Supervisor, Revenue Protection Department, Arizona Public Service, Metering International - Issue 1, 2001. January 29, 2001.

[16] Extent of Energy Division on Customer Premises for Canadian Utilities.

[17] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365. This report describes three field studies at three utilities in the United States that inspected meters at over 1000 small- and medium-sized industrial and commercial sites and discusses the available options for utilities seeking to reduce their metering losses.

"Measured in dollars, this gives the following result: A 1.5% average loss corresponds to about $30 million annually for a utility with a million customers and $2 billion of revenue. This equates to about $30 per customer. If the loss is at the upper end of the range, that is 3%, the loss for the same utility corresponds to about $60 million per year, or $60 per customer."

Itron Report to U.S. Department of Energy

In a report submitted to the U.S. Department of Energy in 2005 Itron stated,

"… theft of energy services costs utilities, their shareholders and consumers billions of dollars each year. The consensus estimate among most industry groups and analysts is that energy theft in the U.S. stands between .5 percent and 3.5 percent of annual gross revenues. With U.S. electricity revenues at $280 billion in the late 1990s, theft of electricity alone would equate to between $1 billion and $10 billion annually. A recent article in the Wall Street Journal estimated the nationwide electricity theft figure at $4 billion per year. And with energy prices increasing sharply nationwide, theft of energy services is only likely to increase as consumers struggle to pay energy bills that have doubled or tripled over the past year."[18]

San Diego Gas & Electric

SDG&E demurred from the CPUC Framework for Business Case guidance that benefits from the reduction of theft were non-quantifiable. It proceeded to quantify benefits from AMI in its own business case based on its own estimates of theft. SDG&E claimed $69.4 million in benefits associated with reduced energy theft (both electric and gas), improved meter accuracy, and reduced billing exceptions.[19]

In its opinion approving SDG&E's AMI project, the CPUC stated,

"At the time of the July 2004 Ruling, it was not clear whether energy theft benefits would be quantifiable. That Ruling did not rule out future quantification of benefits. SDG&E has in fact quantified these benefits. We have reviewed SDG&E's calculations of energy theft benefits and find them to be reasonable."[20]

---

[18] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency*, A Report to the U.S. Department of Energy, Itron. October 2005.

[19] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC, March 28, 2006.

[20] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

However, there was a procedural qualifier:

"It is unreasonable for SDG&E to include benefits which are not within the scope of benefits envisioned for this proceeding and therefore operational benefits should be reduced by $14.5 million."

Further, SDG&E claimed that no more than 0.65% of electricity revenue is lost due to meter error, energy theft, and unaccounted for energy, including meters that fail and mechanical meters that slow down over time as mechanical parts wear out.

In response to a CPUC data request, SDG&E reiterated that many references provide industry estimates for energy theft and all are consistently in the 1-2% range. The explanation for the basis of this figure was that total losses are not known. Field studies at samples of meter sites uncovered approximately that number of incidences of theft, and five sites published studies that report theft in that range.[21]

Hydro One Estimate

Non-technical losses were estimated by Hydro One by reviewing losses from theft, meter inaccuracies, and unmetered energy in other jurisdictions. Based on an overview of the non-technical losses value from utilities across North America, United Kingdom, and Australia, a value of 1.2% was recommended as a reasonable estimate.

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[22]

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold. The upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors.

"In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold, this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales."[23]

[21] DRA Data Request Number 15, A.05-03-015, SDG&E Response.

[22] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Caryn Hough. 1998.

[23] Distribution Line Loss, Exhibit A, Tab 15, Schedule 2, 2006 Distribution Rate Application (EB-2005-0378), Filed August 17, 2005.

Industry Reports

Industry experts estimate that on average, utilities are losing between 2% and 4% in revenues in the meter-to-cash cycle. Studies on electric and gas meter-to-cash cycle losses, also referred to as non-technical revenue losses, indicate that 80% of these losses can be attributed to theft, defective metering, and soft shutoff policies.[24]

Limitation

Some estimates of loss percentages (for example, the 1.5% figure) seem to be predicated mostly on losses from theft. Most of these loss estimates include only the detection of simple energy theft. There may be thefts that are not detected due to sophisticated bypass.[25] Other contributors to non-technical losses, such as defective meters and billing errors, should be given greater weight when deciding on the most likely percentage. Thus, the 1.5% figure is considered as being at the low end of the estimate for non-technical losses.

Revenue Loss

Considering the referenced studies and reports, statistics and analysis, and the opinions of industry experts in revenue protection, a reasonable percentage for non-technical losses is 2.0%. There are indications that the associated revenue loss might be at a lower level, say 1.4%. Some individual company studies suggest that the ratio for revenue losses is lower than the percentage for energy losses. An opposing argument points to the revenue effect due to higher rates reflecting rising energy costs. Nonetheless, for purposes of this study and for comparisons with other estimates in the industry, applying the 2% ratio to revenue seems credible.[26]

The statistical measures for technical and non-technical losses in terms of energy are relatively constant at around 6.1% in the United States. Although there are reasons to argue that technical losses have increased over the past ten years due to congestion, these technical variances are not thought to be greater than the variance in the ratio for losses using aggregate figures. A major study of transmission and distribution losses would be required to conclude otherwise.

Although the statistical measures do not differentiate between transmission and distribution losses, let alone identify non-technical losses (which are, after all, "unaccounted for"), the ratio for non-technical losses measured in terms of energy units cannot reasonably be larger than 4%, given the relative constancy of transmission losses.

---

[24] Ken Silverstein, Editor-in-Chief, *EnergyBiz Insider*.

[25] There are reasons for bypassing the electric system than avoiding payment. One is the concealment of illegal activity. For example, the main source of electrical theft in Canada derives from indoor marijuana grow operations. The Electricity Distributors Association (Ontario) says statistics show grow operators steal an average of $1500 of electricity per kilowatt-hours per day or 10 times the electricity consumption in an average home. Estimates in Ontario, Canada, alone list over a $500 million power theft loss. Reports of seizures of large indoor grow operations list over a 90% electrical theft/bypass rate.

[26] In the absence of industrywide studies of technical and non-technical losses using a consistent methodology, this is a reasonable and sufficient basis for a discussion of the impact of AMI on non-technical losses.

The findings of numerous studies vary widely with respect to the level of non-technical losses, and even more so when imputing non-technical revenue losses.[27] Estimates of tamper rates range from 1.36% to 1.72%. Metering surveys indicate that defective meters may range from 2.16% to 6.5% of the total installed base. Related revenue losses are imputed anywhere from 0.50% to 3.5%. Many of the differences among these estimates derive from analyzing different customer bases and service territories while other differences relate to measurement difficulties with technical losses.

Estimates of non-technical revenue losses range from 0.5% to 4.0% of annual revenue. The 0.5% estimate is so low as to be almost a margin of error in estimation. Most likely, it relates to simple tampering, excluding by-pass and other sources of non-technical losses. The 4.0% estimate is unrealistically high, most likely based on worst-case scenarios.

Non-technical revenue losses most likely fall within a much narrower range: 1.65% to 2.15%, depending on the utility and service territory. Non-technical revenue losses, within this percentage range, over the past ten years are shown in Figure 1-5.[28] A "mode" of 2% would appear reasonable and reflective of the impact on distribution utilities.

[27] Tamper rates and meter defect information are largely taken from surveys, not a complete census of customer bases. These are subject to wide variances, especially between utilities with different customer mixes. With few surveys at a limited number of utilities, it is difficult to apply them on a global scale.

[28] It should be kept in mind that the growth in non-technical revenue losses over the past ten years is a function of both the level of revenue and the non-technical loss rate. Utility revenues have increased significantly over the past ten years with the rise in energy costs. Thus, even while assuming a constant non-technical loss ratio and undertaking vigorous revenue assurance measures, the impact on revenue is increasing significantly. Further, high costs and rates may lead to increased theft by tampering and diversion by changing the risk/reward ratio. High costs make the "reward" more attractive; AMI/MDMS is a resource for increasing the "risk."

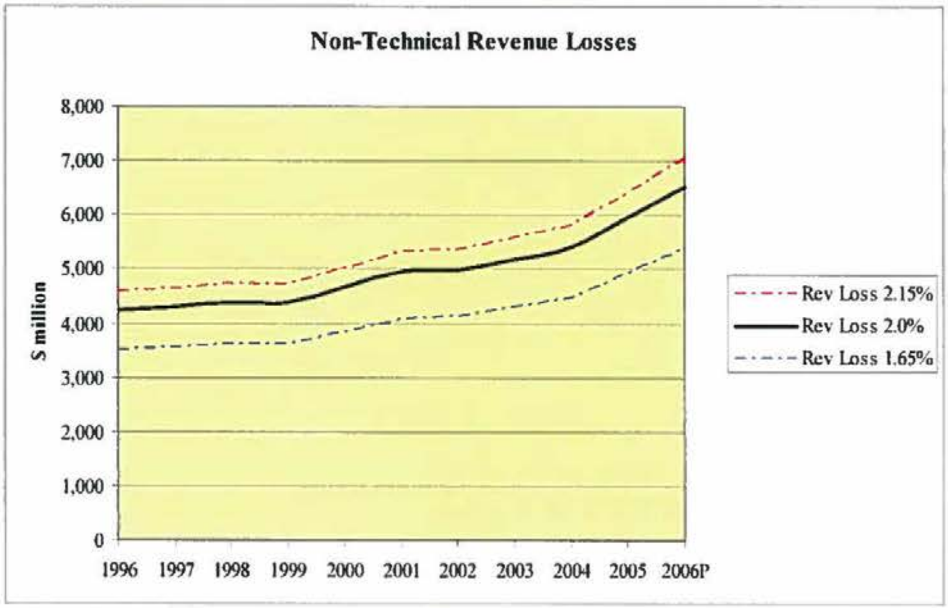


Figure 1-5
Non-Technical Revenue Losses by Year

Based on the 2% rate, non-technical revenue losses are estimated at $6.5 billion for 2006.

International Comparisons

United Kingdom

During the 1980s, some UK electricity companies were losing 2-½% of their total sales because of illegal abstraction (theft) alone. The worst hit areas were London, Merseyside, and Glasgow, with the Northeast having the least amount of theft losses.

Data concerning losses were gained by inter-company comparisons, statistical studies, and engineering studies along with comprehensive studies on street lighting loads to determine distribution system losses and units used in unmetered supplies. This work was underpinned by a number of substation metering exercises whereby meters on particular feeder cables in substations were used to compare the summated meter readings from the properties supplied by those cables.[29]

[29] *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Fellow of the Institution of Electrical Engineers (UK). Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

Overall, Manweb[30] concluded that distribution losses accounted for 5% losses, unmetered supplies (for example, street lights) accounted for 1% losses, and theft accounted for 2-½% losses. This was evidenced by the various studies, metering exercises, signs of serious interference found, and the number of successful prosecutions.

Estimates from four distribution utilities, however, indicate that non-technical losses account for about 3 to 9% of total losses on distribution networks in Great Britain.[31]

Other studies of theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold.[32]

Ontario, Canada

Based on an overview of the non-technical losses from utilities across North America, United Kingdom, and Australia, Hydro One considers a value of 1.2% to be a reasonable estimate for Ontario.[33] This ratio is in line with typical losses incurred by other utilities with a similar mix of rural and urban customers in Ontario. However, it may be low when losses from meter bypass in rural areas are fully discovered and accounted for.[34]

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California, "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[35]

India

The problem of electricity theft is most pronounced in India, where an estimated one-third of all power is "free." Many users there run their own wires from the distribution lines into their homes. This is a tremendous hazard as the cables are strung through populated alley ways and corridors.

[30] Manweb, a subsidiary of Scottish Power, was among the first electricity companies to gain approval to enter the new market for electricity metering services to domestic and small business customers, which was opened up to competition in June 2004. Under the new arrangements, electricity suppliers have freedom to choose their own agent to collect and process meter readings and to provide and maintain metering equipment. These activities were previously provided on a monopoly basis by the local electricity company.

[31] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[32] *Report on Distribution System Losses*, J.A.K. Douglas, N.J.L. Randles, PB Power report 10025D008, Victoria Australia. February 4, 2000.

[33] *Distribution System Energy Losses at Hydro One*, Kinectrics Inc. Report No.: K-011568-001-RA-0001-R00. July 20, 2005.

[34] Refer to the accounts of theft in Calgary, *Electricity Theft and Marijuana Grow Operations*.

[35] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Carolyn Hough, California Energy Commission. 1998.

Energy theft costs India's utilities close to $5 billion a year and is the major contribution to operating deficits.

These non-technical losses have costs well beyond the impact on revenue. The revenue losses impact the financial strength of the utility to the point that investments in infrastructure are prohibited. When energy is not paid for, the company is not recovering its costs and, thus, is unable to invest in new infrastructure. The result is regular power cuts. Without these investments, service degrades and further losses—technical and non-technical—ensue. For example, in May 2008 the Maharashtra State Electricity Board of India announced that it has been able to reduce non-technical losses by as much as 8% and says that, as a result, it will be able to reduce power cuts in the state.

United States

Losses in the United States in the 3% range seem low in comparison to India. However, when the related revenue losses are calculated, the number captures the attention of regulators and the electric utility industry. There are losers from non-technical losses in the United States as well as less developed countries.

Distribution Loss Ratios

Distribution loss ratios—calculated from generation to end-user—can be compared internationally (Figure 1-6). For developed countries, the ratio is lower than 8%, with non-technical losses in the range of 1.5% to 3.5%. For countries still developing, the loss ratios are more than double, with non-technical losses (mostly from theft) being the major explanation.

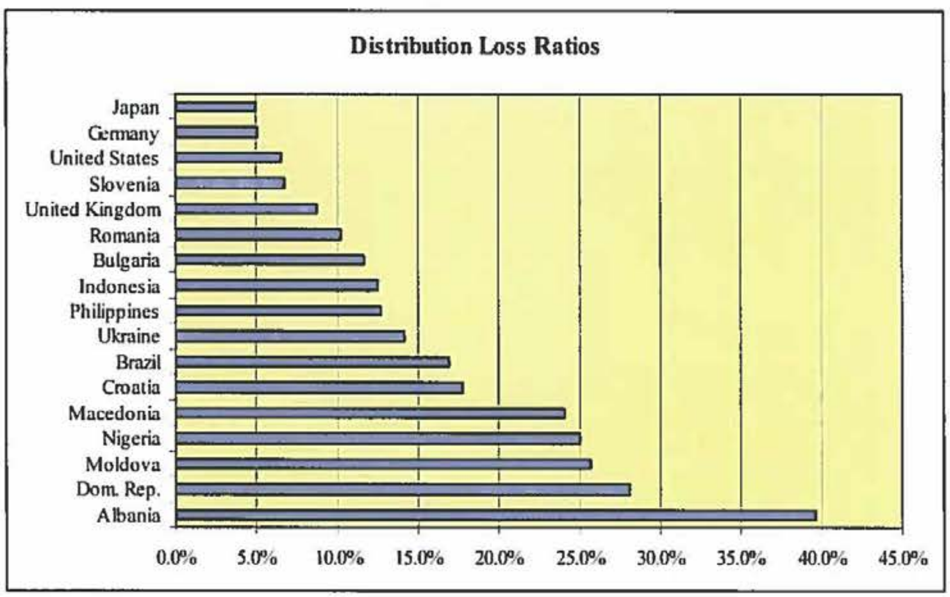


Figure 1-6
Distribution Loss Ratios

Revenue loss resulting from non-technical losses exceeds 40% in many developing countries.[36] Revenue losses of these dimensions have a significant impact on the local economy.[37] It is a problem that governments and utilities must address together. As one observer remarked, "The theft of energy is the largest systematic theft in the world."[38]

Losses Other Than Revenue

Safety

While theft of service is a huge source of revenue loss by any measure, more importantly it poses a serious threat to the safety not only of individuals involved in the theft, but also of utility personnel and the general public.[39] Meter tampering, bypassing, and other means used to steal service place those committing the theft, their families, emergency service personnel, and innocent bystanders in grave danger.

In situations where power must be shut off within a home or business, emergency personnel are at risk of electrocution or burning because meters that have been tampered with may remain "live."

Safety hazards can result in serious injury or death and destruction of public or personal property. These hazards have very real costs associated with them in terms of medical care, loss of productivity, damage to property, and sometimes even services with economic value.

Efficiency

Since losses are factored into the revenue requirement by way of distribution loss factors, and thus included in the rate base, some conclude that there is no real revenue loss to the distribution utility. In this view, reductions in non-technical losses merely shift the source of revenue for the utility among ratepayers. Aside from issues of basic fairness in having some ratepayers bear the burden of non-payment by other users of electricity, the existence of non-technical losses introduces basic inefficiencies into the distribution system.

Non-technical losses have an "efficiency cost." Although a reduction in non-technical losses will represent a reallocation of, rather than a reduction in, electricity consumption, the misallocation of resources introduces inefficiencies. Instead of a direct improvement in social welfare, a redistribution of benefits occurs from those agents whose consumption has been

[36] *Controlling Electricity Theft and Improving Revenue, Reforming the Power Sector*, Note Number 272, Public Policy for the Private Sector, World Bank. September 2004.

[37] For example, in India electricity theft leads to annual losses estimated at US$4.5 billion, about 1.5% of GDP. The losers are honest consumers, poor people, and those without connections, who bear the burden of high tariffs, system inefficiencies, and inadequate and unreliable power supply.

[38] Kurt W. Roussell, Manager, Revenue Protection, We Energies.

[39] *How Safe is your Utility from Theft of Service?* Revenue Protection Task Force, Energy Association of Pennsylvania. The objective of the Revenue Protection Task Force is to provide education to the public, law enforcement agencies, legislators, and regulators about the facts of energy theft in terms of frequency and quantity of theft.

identified to suppliers and general consumers. However, if consumed units of electricity are correctly allocated, cost signals should encourage a more efficient level of demand for electricity.[40]

The trend toward performance-based rate making highlights the issue of losses where their reduction may change this situation and put in place greater incentives for utilities to reduce non-technical losses.

The reduction of non-technical losses reduces these inefficiencies and rectifies a situation where "lost revenues from energy theft and failure to detect meter errors put upward pressure on rates." Ratepayers benefit when energy theft and meter errors are detected sooner and costs are shifted to the customer who actually used the energy."[41]

Then there is the question of basic fairness. "Although the total revenue requirement does not change through the reduction of energy theft, all law-abiding customers will have lower rates. This is a quantifiable and tangible benefit for our customers."[42]

Technical and commercial losses, however defined, affect allowed tariff levels through a two-step process as shown in Figure 1-7:

Step 1 – Calculation of T&C

$$T\&C = 1 - \left\{ \frac{\text{Energy Units Billed}}{\text{Energy Units Purchased}} \times \frac{\text{Collection in \$}}{\text{Billing in \$}} \right\}$$

Step 2 – Gross-up Calculation

$$\text{Allowed Units of power purchased} = \frac{1}{1 - T\&C}$$

Figure 1-7
Calculations

[40] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[41] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

[42] Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 29, Prepared Rebuttal Testimony of James Teeter, SGD&E before the CPUC. September 7, 2006.

The level of losses, therefore, has a direct impact on the price of electricity consumed. The cost of losses is generally spread out over all users.

It must be noted that the full cost of technical losses on a network consists of not only the value of the electricity lost, but also the cost of providing the additional transportation capacity and the cost of the environmental impacts associated with the additional generation that is needed to cover losses.

Unmetered Demand

Loss in revenue results from the uncontrolled increase in demand from unmetered customers. Also, dissatisfied and angry customers can overload the system, which may lead to faults in the distribution network and load shedding with consequent loss of revenue from customers affected.

Energy Theft Impact on Revenue Ratepayer

Energy theft occurs and is a cost of doing business that is borne by all ratepayers. Any reduction in energy theft from the implementation of automated meters will enable SCE to spread its revenue requirement over more energy sales, thus reducing rates.

Edison Smartconnect™ Deployment Funding and Cost Recovery, Errata to Exhibit 3: Financial Assessment And Cost Benefit Analysis, California Public Utilities Commission. December 5, 2007.

Investigation and Prosecution

The adverse financial impacts of energy theft include lost revenues and the costs for investigation and prosecution. Although these costs are not included in non-technical losses, they are borne by ratepayers nonetheless.

Societal Cost and Theft Comparisons

The public is aware of losses from identity theft, stolen credit cards, hold-ups, and personal robberies. In contrast, the theft of electric and natural gas service, despite the magnitude of the problem, has not received much attention from the public or from regulators.

The cost of non-technical losses in electricity distribution to society can be placed in perspective by comparing it to property crimes.

In the Uniform Crime Reporting Program[43] (UCR), property crime includes the offenses of burglary, larceny-theft, motor vehicle theft, and arson. The object of the theft-type offenses is the taking of money or property, but there is no force or threat of force against the victims. The property crime category includes arson because the offense involves the destruction of property. Property crimes accounted for an estimated $17.6 billion dollars in losses.

[43] *Crime in the US, 2006* US Department of Justice, Federal Bureau of Investigation. September 2007.

Larceny-theft is the crime category closest to theft of electrical services. The UCR Program defines larceny-theft as the unlawful taking, carrying, leading, or riding away of property from the possession or constructive possession of another. Examples are thefts of bicycles, motor vehicle parts and accessories, shoplifting, pocket-picking, or the stealing of any property or article that is not taken by force and violence or by fraud. There were an estimated $5.6 billion dollars in lost property in 2006 as a result of larceny-theft offenses.

The revenue estimate for non-technical losses is $6.5 billion. A comparison of non-technical losses to other thefts crimes is shown in Figure 1-8.

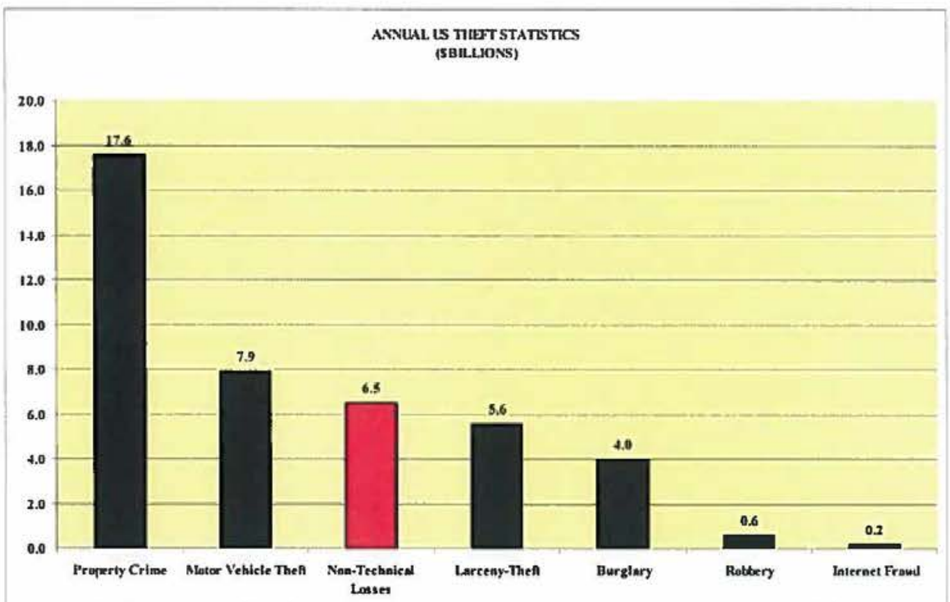


Figure 1-8
Annual U.S. Theft Statistics

2
CHAPTER 2

Revenue Security

"Revenue security" is an apt term to describe the activities intended to protect the distribution system and network resources from external attack or internal subversion, especially theft from diversion by means of "meter bypass." Revenue security ensures that the resources of the electricity industry are available only to those who have the legitimate right to use them. Thus, "revenue security" describes the precautions taken to ensure against non-technical losses.

The activities involved in revenue security are oftentimes called "revenue protection", or more recently, "revenue assurance." Three definitions are presented in the inset below.

Definitions

The term "Revenue Protection" is a colloquialism used by the English-speaking world to refer to the prevention, detection, and recovery of losses caused by interference with electricity and gas supplies.
UK Revenue Protection Association

Revenue Protection is a set of activities to reduce the unauthorized use of energy, ensure metering accuracy and detect meter tampering, and identify customers who fraudulently obtain service.
Kurt W. Roussell, Manager-Revenue Protection, We Energies

Revenue Assurance: A set of activities designed to increase the revenue from providing electric service to ultimate customers, including locating meters without associated customer accounts, relatively high line losses compared with other similar locations, energy theft, and/or improper metering installations.
Federal Energy Regulatory Commission (FERC)

The revenue security function is traditionally performed by utilities' revenue protection departments, using data collected by manual meter reads. The introduction of remote meter-reading technology—beginning with automated meter reading and later including advanced metering systems—changed methods and procedures used for revenue protection, eventually evolving to revenue assurance. These changes in technology and their impact on revenue security are the subject of this chapter.

Meter Readers: The Need for "Eyes in the Field"

The time-honored way of finding electricity theft is through detection by meter-reading personnel. Meter readers are trained and experienced in detecting theft from meter tampering and bypass, and they inspect meters for tampering during regularly scheduled on-site meter reads.

The methods of meter tampering vary from elementary to sophisticated. The ones most commonly detected by meter readers are shown in the insert below.

Common Tampering Techniques

- Stolen meter
- Magnets
- Wire tap on service
- Inverting meter
- Debris, foreign objects inside glass
- Potential link
- Internal—gears, disc, dial hands, adjustment screws
- Load (customer) wires connected to line
- Jumpers—wires connecting line to customer connection

There is some apprehension that AMI, notwithstanding the tamper detection mechanisms in AMI systems, may increase energy theft due to the loss of "eyes in the field" when meter readers no longer visit every meter every month. For example, AMI does not specifically detect and report some kinds of theft, such as taps ahead of the meter.

> "The overall conclusion is that AMR, although it can provide valid and useful assistance in the detection of theft and interference if the system is well thought out and well designed, is not the full answer and that it would be prudent to retain or develop some form of back-up, in terms of conventional revenue protection measures. For instance, one company with an AMR system is considering a new post of Meter Inspector to carry out periodic inspections of customer installations."[44]

There is a concern that AMI—especially after complete meter replacement—will lead to more sophisticated thefts and more bypass, both above and below ground.

Many of these apprehensions and misgivings are founded in experiences with earlier AMR installations. While these are valid concerns, a comparison of AMR and AMI should bring perspective.

[44] OFGEM Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association, Version 3 (final). March 15, 2006.

Comparison of AMR and AMI

Energy theft detection capabilities in AMI systems are far superior to those in simple, first-generation AMR systems. The "infrastructure" in an AMI system includes information systems capable of processing large amounts of interval data for use in discovery of energy theft. This contrasts dramatically with AMR systems, which generally automate only the monthly consumption read.

Prior AMR (not AMI) installations involved tamper alarms so sensitive that false alarms could easily overwhelm the system. Unlike the AMR systems, AMI can intelligently sort and prioritize tamper flags, reducing unnecessary investigations. In addition, AMI, using solid-state meters, is far more tamper-proof than AMR. For example, a solid-state electric meter does not have a spinning disc that can be slowed down. Inverted meters also can be detected quickly through the daily collection of hourly data. Other forms of theft will be discovered through investigation of tamper flags.

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. MDMS applications are essential in the delivery of these solutions. The effectiveness of these solutions is not yet fully documented, as AMI/MDMS have not been deployed on a wide scale over a long period of time. Nevertheless, all indications are that they will be successful when combined with aggressive revenue protection programs with well-trained meter revenue protection agents. With off-cycle reads being supplied through the MDMS, as much as 95% of field service orders for special reads can be eliminated.45

Many on-site inspections by traditional meter readers were focused specifically upon meter tampering and meter anomalies, but did not reach more deeply into supply and service wiring where taps and bypasses are likely to be found. AMI reduces the number of routine site inspections and allows the meter revenue protection agent to concentrate on serious issues of diversion.

AMI Contribution to Theft Reduction

After the installation of AMI, it is expected that utilities may uncover a substantial number of previously unknown sources of diversion. Indeed, some utilities are planning to add staff to handle the increased number of theft cases that will be uncovered.

"During the installation period, SDG&E will need six additional Meter Revenue Protection agents to handle the large number of energy theft cases the company anticipates discovering when the new meters are installed. There also will be some transitional costs during the first year to determine the best way to process false positive signals. After AMI installation is complete, SDG&E will require two additional agents to prosecute the large number of energy thefts we expect to uncover."[46]

[45] *Meter Data Management System—What, Why, When, and How*, Hahn Tram and Chris Ash, System Engineer, Enspiria Solutions. August 29, 2005.

[46] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared

With comprehensive AMI/MDMS and vigorous meter revenue protection programs, the most likely outcome is that AMI will bring a reduction in non-technical losses due to theft.

Meter Reader Shortcomings

At the same time, it should be kept in mind that there is an existing level of theft occurring even with manual readers in the field. In some cases, field-level engineers have not been made responsible or accountable for the energy input to their areas, the energy billed, or the revenue. This inattentiveness contributes to non-technical losses.

The personnel best qualified to detect metering problems are often the ones responsible for the faulty metering installation in the first place. In some countries, meter technicians and readers are complicit in meter tampering and bypass.

Meter Defects

Real-time two-way communications offered by AMI allow a utility to detect meter defects that might degrade to failure before the utility could learn about them from manual meter reads at intervals that are often as long as six or twelve months. Furthermore, there is evidence that meter readers miss some amount of meter tampering.[47] There are instances when distribution utilities have discovered meter tampering when deploying AMI that had not been reported by meter readers.

Need for On-site Inspections Post-AMI Deployment

Periodic on-site visits by meter inspectors carefully trained to know what they are looking for are an essential tool in the detection of theft in a post-AMI environment. It is good practice to visit randomly and inspect meters on a recurring basis. Some utilities plan such inspections on a 5-year cycle.

Customers who engage in diversion activities usually act to prevent access for meter reading, and procedures to require and enforce inspection are essential. Traditional meter readers may not be trained for new, more creative methods of energy diversion and must be schooled to recognize the sophisticated tampering methods that may follow the deployment of AMI. In addition, it should be noted that with advanced metering technology, various system abnormalities can resemble power theft. Thus, the staff of revenue assurance departments must have a higher level of training, technical know-how, leadership, judgment, and inquisitiveness.[48]

Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

[47] In an extensive study undertaken in the Merseyside area over a five-year period, Revenue Protection staff acted as meter-reading staff and gained valuable intelligence. It became apparent that meter readers were poor at recording signs of interference with, say, only 1 in 15 of them providing reliable reports. *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

[48] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

The transformation from "meter reader" to "meter revenue protection agent" is a core change in the evolution from traditional meter reading to AMI.

> "The old-fashioned methods are dwindling."
> Ron Jones, Residential Meter Services Manager, JEA

Meter Readers

Meter readers read electric, gas, water, or steam consumption meters and record the volume used. They serve both residential and commercial consumers. The basic duty of a meter reader is to walk or drive along a route and read customers' consumption from a tracking device. Accuracy is the most important part of the job, as companies rely on readers to provide the information they need to bill their customers.

Other duties include inspecting the meters and their connections for any defects or damage, supplying repair and maintenance workers with the necessary information to fix damaged meters. They keep track of customers' average usage and record reasons for any extreme fluctuations in volume. Meter readers are constantly aware of any abnormal behavior or consumption that might indicate an unauthorized connection. They may turn on service for new occupants and turn off service for questionable behavior or nonpayment of charges.

Median annual earnings of utility meter readers in May 2006 were $30,330. The middle 50 percent earned between $23,580 and $39,320. The lowest 10 percent earned less than $18,970, and the highest 10 percent earned more than $49,150. Employee benefits vary greatly between companies and may not be offered for part-time workers. If uniforms are required, employers generally provide them or offer an allowance to purchase them.

Tasks

- Read electric, gas, water, or steam consumption meters and enter data in route books or hand-held computers.
- Walk or drive vehicles along established routes to take readings of meter dials.
- Upload into office computers all information collected on hand-held computers during meter rounds, or return route books or hand-hand computers to business offices so that data can be compiled.
- Verify readings in cases where consumption appears to be abnormal, and record possible reasons for fluctuations.
- Inspect meters for unauthorized connections, defects, and damage such as broken seals.
- Report to service departments any problems such as meter irregularities, damaged equipment, or impediments to meter access, including dogs.
- Answer customers' questions about services and charges, or direct them to customer service centers.
- Update client address and meter location information.
- Leave messages to arrange different times to read meters in cases in which meters are not accessible.
- Connect and disconnect utility services at specific locations.

Work Activities

- Documenting/Record Information—Entering, transcribing, recording, storing, or maintaining information in written or electronic/magnetic form.
- Collect Information—Observing, receiving, and otherwise obtaining information from all relevant sources.
- Communicate with Supervisors, Peers, or Subordinates—Providing information to supervisors, co-workers, and subordinates by telephone, in written form, e-mail, or in person.
- Process Information—Compiling coding, categorizing, calculating, tabulating, auditing, or verifying information or data.
- Work Directly with the Public—Dealing directly with the public. This includes contact with customers, representing the organization to customers, the public, government, and other external sources. Information can be exchanged in person, in writing, or by telephone or e-mail.

Bureau of Labor Statistics, U.S. Department of Labor, *Occupational Outlook Handbook*, 2008-09 Edition.

Revenue Protection: Transition from Traditional to AMI

The first step in transitioning from traditional meter reading to remote was AMR, which replaced meter readers with remote meter reading via one way communications. The primary driver for this was savings on meter readers. This introduced difficulties with respect to theft detection. These difficulties were overcome with the evolution from AMR to AMI. AMI, coupled with MDMS, offers considerable advantages with respect to theft detection and the reduction of non-technical losses.

When AMR was introduced, there was an expectation that revenue protection would benefit greatly, and the need for revenue protection analysts and investigators would be greatly diminished. Tamper flags would be the solution. This did not prove out during large-scale deployment. In fact, AMR produced a flood of tamper flags that had the practical effect of being impossible to manage and, thus, being ignored. Except now, the "eyes in the field" were gone.

Most AMR meters have revenue-protection-related features that are useful for detecting novice tamperers, such as reverse rotation (meter being inverted by the customer) and magnetic presence (external magnets placed on meter in an attempt to reduce its registration).

However, there are limitations to AMR's ability to detect theft by experienced or professional tamperers who seek to defeat the system by installing taps ahead of the meter (for example, masthead), limit the ability to detect "last gasp" while installing bypass behind the meter, or using conventional tactics to slow disk rotation on retrofitted meters. Of course, stolen meters placed in-service by customers are difficult to locate.

Tamper Flag Problem

Several companies that have installed large-scale AMR have experienced problems with tamper flags. AMR has functionality for determining valid flags, but AMR supplies more information than utilities are able to monitor. There are problems with tamper data because of volume and the number of variables that must be taken into account for validation and separating the "urgent" and "genuine" interference cases from false alarms and technical faults. Utilities had to develop their own algorithms for dealing with this.

Further, AMR is not able to cover the types of theft that tamper flags do not report. It cannot detect diversions where the meter is bypassed completely (by "tapping" into the cutout or the wiring from it ahead of the meter). There is no way of detecting this, other than from analysis of consumption. Additionally, AMR is not able to monitor consumption and detect abnormalities which might be due to theft.

The solution to this is offered by AMI and MDMS.

The limited benefit of AMR for theft detection and problems with tamper flags pointed toward the need for MDMS, which only really came into its own later, when AMI was introduced. The awareness of data management requirements, after the experiences with AMR, was a major developmental turning point in the evolution of AMI applications for theft detection and non-technical loss reduction.

AMI provides information for detecting certain kinds of losses, such as detecting recurring tampers from upside-down meters and dial tampering, site and installation diagnostic problems, consumption on inactive accounts, and detailed data for trends and comparisons. However, AMI offers little or no protection from "one-time tampers" (adjustment screws, register tampering, magnetic circuit alteration, electrical circuit alteration or alternations external to the meter, magnets, disk "pinning", stolen meters and, most obviously, taps and jumpers.) These can only be detected using customer modeling (MDMS) and other revenue assurance tools as part of pro-active revenue assurance programs and systems, staffed by well trained and knowledgeable people.[49]

AMI provides a valuable tool to help utilities reduce lost revenue in each one of these areas, but AMI "... is only a tool—it must be coupled with *systems, people, and experience*."[50]

The transition in the detection process from traditional to AMI is summarized in Table 2-1.

Table 2-1
Comparison of Detection Process

Comparison of Detection Process
Traditional vs. AMI

Detection Process		
Traditional	**AMI**	**Change**
Meter readers	Solid-state meters	Improved reading accuracy
Tips/utility hotline	Remote meter reading	Eliminates need for meter reader
Meter-reading reports	Two-way communications	Permits more frequent readings
Statistical analysis	Remote diagnostics	Discovers malfunctioning meters
Proactive sweeps	MDMS	Supports enhanced customer service
Collateral investigation	Meter revenue protection agents	Meter Audits

Transition to Revenue Assurance

In the 1970s and 1980s, these activities were called "current diversion." In the 1990s, they were called "revenue protection." Today, the preferred term is "revenue assurance." Revenue assurance conveys the full meaning of its role in a distribution utility, namely assuring that all the revenue owed the utility is collected.

Revenue assurance includes the following:

- Theft detection and follow-up
- Metering mistakes—for example, malfunctions, meter constants, and billing errors

[49] One study reported an average accuracy of 35% using AMI flags with consumer models. This is much better than AMI flags alone (4%) and better than customer models alone (29%) and is considered a very good "hit rate." *Revenue Protection and AMI Come Together*, Ed Malemezian. June 25, 2007.

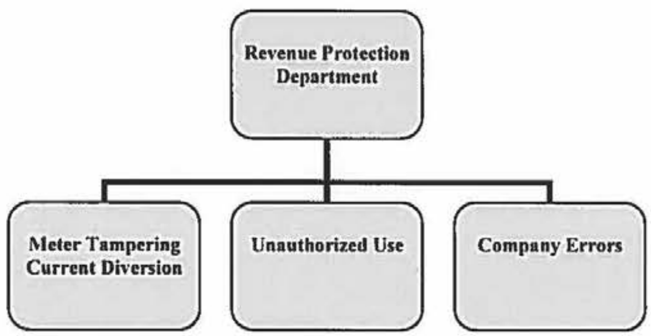
[50] *AMR Tamper Detection—The Good, the Bad, and the Possibilities*, Ed Malemezian

- Consumption on inactive accounts
- Collections

Revenue Protection Department

As revenue protection transitioned to revenue assurance, so did the responsible department and staff. The responsibilities remain the same, namely personnel training (mostly meter readers), receiving information on electricity theft from customers and staff, analyzing consumer load profiles for drastic changes compared to past trends, assessing charges for electricity theft and equipment tampering, and—if necessary—prosecuting clients who endanger themselves or field staff. The main source of information that utilities traditionally use to detect and prevent electricity theft is the meter-reading staff.

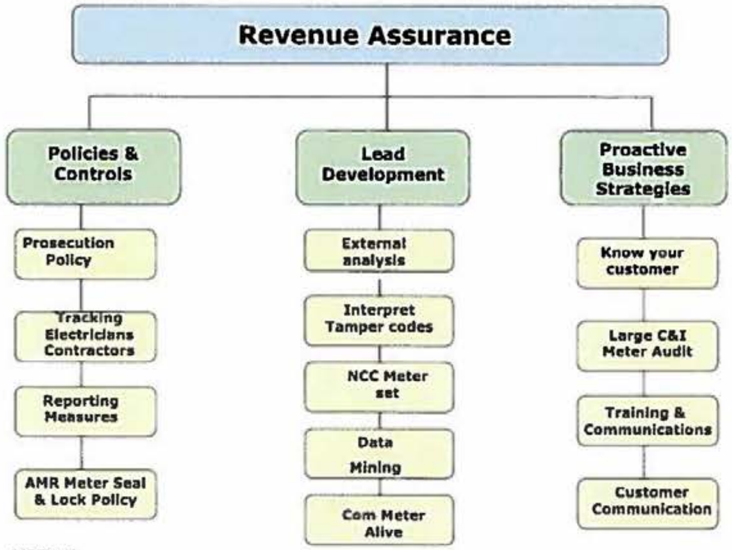
The traditional organization for discharging these responsibilities is illustrated in Figure 2-1. The three major areas where revenue (non-technical) losses were discovered by the Revenue Protection Department were meter tampering and current diversion, unauthorized use, and company errors.



Source: IURPA/WSUTA Conference, Las Vegas, Kurt W. Roussell, Revenue Protection, WEC.

Figure 2-1
Revenue Protection Department

Revenue assurance, on the other hand, is a term that describes the revenue security function as performed with AMI / MDMS. The new Revenue Assurance Department does not rely on manual meter readers—the "eyes in the field." Rather, there is a heavy reliance on policies and controls, lead development using analytical data and customer profiles, and proactive business strategies that include meter audits and customer communications. Meter readers are not absent from this department, but they are no longer depended on so extensively. Rather, revenue assurance with AMI relies heavily on MDMS, analytical tools, and analysts.
The organization of a typical Revenue Assurance Department under AMI is shown in Figure 2-2.



Source: NSTAR

Figure 2-2
Revenue Assurance

Revenue Protection Using AMI and MDMS

The AMI data collection front end detects and reports unexpected usage patterns. Typically, consumption profiles are established for each meter through automatic assignment of profiles using CIS supplied data and manually assigned profiles for specific or temporary situations. Each profile can consist of one or more checks. These checks can be enabled and disabled by the time of the year. They can be used to find diversions for monitoring seasonal meters. Drops in usage can be correlated by power outages for each meter as compared with other meters on the same transformer. All of the applicable checks need to be flexible enough to allow assignment of predetermined percentage changes in consumption, with day of the week and date range selection set up as required for each profile.

The Meter Data Management System (MDMS) receives additional information to aide in more filtering. Typically weather data, utility work order tickets, account status, and limited demographic data are brought in to aide in the filtering. Monthly and daily consumption data are collected and compared on a regular basis against profiles established for each customer. This data can be normalized by weather and other variable parameters. Effective usage is compared against baseline usage to generate candidate lists. These lists are then further filtered by additional information from tamper flags and more advanced consumption patterns to develop suspect lists. The suspect lists are organized and sent to the field for investigation. Various tools are often provided to drill down by customer and groups of customers.

The availability of interval data raises the bar to yet a higher level. Tools to compare actual interval usage against expected interval usage provide a much better picture in spotting the outliers. Advanced statistical techniques are used to generate appropriate algorithms that analyze the data. Science and art come together in making a success of this. Statistics also can be helpful in establishing confidence levels of the suspect lists, allowing the lists to be cranked up or down to match the availability of investigators to do the follow-up work.

Tests by transformer and geography provide another view of customer consumption patterns. When a utility utilizes account-to-transformer mapping, it allows the comparison of usage across similar homes served by the same transformer to look for low usage outliers, and to correlate changing usage patterns with blinks, reverse rotation, or other events. This mapping also enables comparison of transformer load to aggregated usage, if the utility installs additional interval meters upstream of the utility transformers. When meter data is supplemented with data from other sources, more views and points of comparison can be created. Examples include creative mining of other CIS fields such as the SIC Code or Customer Name to find groups of customers with similar names.

The Revenue Protection application receives all relevant data from the utility CIS, historical and present temperature data from an internet based source, triggered flags from the AMI tamper database, geographical information from external sources, SIC codes and NAIC codes from CIS, demographic data from paid or public sources, operating hours from public sources and feet-on-the-ground research, as well as daily and interval consumption data from the utility AMI or MDM systems.

Profiles and consumer models are built from sets of flexible rules. These are assigned to each account and analyzed on a regular basis. Tools include the ability to drill down by customer or group and to score each deviation from expected consumption patterns by numerous methods. Candidate lists and suspect lists are managed, and feedback is provided for both tracking results and improving the process.

Revenue Protection and AMI Come Together, Ed Malemezian. June 25, 2007.

MDMS Theft Reports

With the advancement of AMR/AMI, the traditional approach of identifying potential theft with a meter reader's visit to the site is becoming obsolete. Aided by MDMS, data analysis provides leads based on usage patterns and other data.[51] This is proving to be an effective approach to identifying theft.[52]

MDMS is used to turn AMI data into leads that can be followed up by revenue assurance teams. MDMS provides "automated exception processing" reports. An exception is when the system sees an event or data circumstance that it is not expecting. Examples with revenue-assurance relevance include meter readings that show lower consumption than expected, meters that do not report any consumption, and readings that show power being used at a supposedly vacant premise.

"Plus or minus 20" reports look at accounts where consumption has gone down by at least twenty percent. Data is reviewed over a thirteen-month period, ensuring that the information reflects seasonal usage patterns.

Another approach looks for unusual usage patterns, such as usage that drops off substantially on weekends. Through the MDMS, utility managers can compare unusual usage reports with power-outage and restoration reports that narrow down dead-end leads. This lowers the cost of collection.

Examples of Reports Using AMR/AMI Data[53]

- An "unplanned outage" report spotlights accounts with more than 10 outages in 30 days. About 40 percent of PECO's theft detection stems from this report.
- A "billing window" report detects meters turned on or off close to the billing period, indicating attempts to force low-balled estimates or pay for only a few days' worth of consumption. This report pinpoints around 35 percent of the utility's theft.
- A "reversed meter" report finds power-out and power-up messages that occur in quick succession if the customer unplugs the meter, then plugs it in upside down to make the register run backward. About 20 percent of PECO's theft shows up via this report.

[51] AMR / AMI tamper indications are analyzed with detailed consumption data, outage information, tickets from work order systems, and numerous external demographics. Advanced analytics are used to establish baseline patterns and profiles for customer accounts. Outliers can easily be identified and followed-up according to procedures established by the revenue assurance department.

[52] For example, at NSTAR, revenue protection billings increased more than 130 percent, while the cost per case processed decreased by 25 percent. The improvement was due to leveraging the lead generation partnership and streamlining the process with automated reports, fewer handoffs and triage of theft cases. *Reducing Revenue Leakage*, Penni McLean-Conner, NSTAR. Electric Light & Power, July 2007.

[53] *Deputizing Your Data: AMI for Revenue Protection*, Betsy Loeff, Electric Power and Light.

AMI Remote Service Disconnect

In certain instances, utilities incur losses when customers leave without disconnecting. In these cases, the utility has active accounts without contracts. Oftentimes, it would take utilities a minimum of thirty days to find active accounts with no contract. This produces non-technical losses.

With AMI, service cut-offs can be "virtual," without dispatching a field service technician to the site. Instead, the utility takes a reading through the AMI system, sends a final bill to the departing customer, and leaves the premises ready for the next resident.

Sometimes the new resident does not call to set up an account after moving into a house or apartment. In these instances, a consumption threshold is set up. Once the threshold is surpassed, the MDMS automatically generates an order for a field service technician to shut off service.

Key Attributes for Revenue Protection—AMI + MDMS

Advanced Meter Infrastructure

- Full two-way communications
- Advanced meter capabilities with extensive diagnostics
- Exponential increase in meter reads and meter data
  Example (500,000 meters):
  1 monthly read = 500,000 reads/month
  1 daily read 500,000 reads/day, 15 million reads/month
  1 hourly read 12M reads/day, 360 million reads/month

Meter Data Management Systems

- Systems to create reports that analysts/investigators can use to research, investigate, and take corrective action
- Energy Diversion will become more innovative with smart metering (without manual meter reading). Data and analytical tools must be used to "outsmart the thieves"

Pros

- Better knowledge of unbilled revenues
- Notification of illegal reconnects
- Ability to examine consumption patterns from daily read information
- Ability to examine 15-minute interval data

Cons

- Loss of regular field visits to examine metering equipment
- Inability to determine connections ahead of the metering scheme
- The meter will tell you only what it sees—not what it doesn't see
- Unless additional services are known, unmetered (unbilled) revenue can occur for years
- The combination of these factors along with the rising cost of energy increases the potential for revenue loss significantly

Source: *Various Applications of Electric Metering & How They Relate to Revenue Protection*, Guy Cattaruzza United Illuminating NURPA. September 19, 2007.

Billing and Customer Service

Along with theft, the billing and customer service problems encountered by traditional manual meter-reading operations are contributors to non-technical losses.

Traditional Billing System[54]

Currently, meter readers travel to customers' meters each month to collect customer usage information (meter reads) with a hand-held data collection device.

These meter reads are used to prepare monthly bills. After the meter-reading route is completed, the customer's meter reads are transferred from the hand-held device to the customer information system. This data transfer must be done at a meter-reading base location. Back-office billing systems then perform a series of data validation routines that will, if warranted, automatically trigger a pre-billing review that may result in bill adjustments. The largest number of bill adjustments is due to meter-reading error.

When customers move from one residence or business to another, field service personnel must visit the meter and complete a "close order" or a "change of account" order to obtain the "end read" for the departing customer and a "start read" for the new customer. A certain number of these orders are "revert to owner" reads where service is left on for the convenience of property owners or managers when a tenant moves. Also, when meter-reading errors are suspected, field service must perform a "read verify" order at the customer's meter.

Billing System with AMI

AMI eliminates field visits as part of the billing process. Instead, utilities obtain meter reads electronically on the date a customer desires rather than on a service order schedule, which is subject to delay due to workload constraints. This reduces error and, thus, non-technical losses. It also improves customer service.

To prevent billing errors, once meter data is captured the billing system performs a series of billing edits prior to sending the customer bill. Despite comprehensive edits, some billing adjustments are required after bills have been sent. Other anomalies (billing exceptions) also are detected after completion of the billing cycle, such as meters in "off" status but registering consumption (OBR), meter failures, and unauthorized energy usage theft. With AMI, many of these billing exceptions will be eliminated and others will be detected more quickly, thus reducing non-technical losses.

Estimating

Estimating is one of the defining issues for which AMI offers a solution and contributes to the reduction of non-technical losses.

---

[54] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

The vast majority of utility customers receive a monthly visit from their utility's meter reader. This meter reader visually reads the electric and/or gas meter, then forwards that information to the utility's billing office to generate a monthly consumption bill. If the meter reader is unable to access the meter,[55] most utilities will proceed to estimate the electricity consumption based on previous usage and recent weather patterns. They will then use that estimate as the basis for the next bill.

Exception reports are another area where estimates are made. After data are collected, they are analyzed, looking for exceptions such as missing reads, zero consumption, idle with consumption, out of range readings, and negative consumption. These transactions are placed in an exception file for review. Actions taken by revenue protection to correct the exceptions include reading, re-reading, checking for malfunction, checking for tampering, or accepting the read and estimates.

It is not uncommon for utilities—particularly those in higher-density urban areas—to estimate ten percent, twenty percent, even thirty percent or more of the meter reads each month for billing purposes. This practice leads to inaccurate billing, increased customer complaints, and higher costs for utilities to investigate and resolve those complaints.

AMI Solution to Estimating

AMI provides accurate, timely, and reliable information about energy use and demand that offers a solution for estimating.

AMI minimizes meter access problems, limiting them to meter installation and inspection upon suspicion of tampering or diversion. AMI eliminates estimated reads and improves meter-reading accuracy, which results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.[56] Further, AMI reads remotely interrogate meters daily, rather than monthly. This identifies bad meters more quickly and avoids much of the estimating.

Thus, AMI offers a solution to estimating, which contributes to the reduction of non-technical losses.

Security

AMI avoids the security risk of giving keys and access to premises to meter readers. This is a concern of high importance in these security conscious times.

[55] A meter cannot be read when it is located in the basement and the consumer is not home; the yard is fenced with a locked gate and a dangerous animal in the yard; customers are threatening or hostile; extreme weather; or when the meter is dead, damaged, or missing.

[56] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency*, A Report to the U.S. Department of Energy, Itron. October 2005.

AMI + MDMS Solution: Importance of Information Technology

A comprehensive revenue assurance program is based on AMI and MDMS.

This constitutes a "holistic approach to revenue recovery"[57] that combines expert analytical resources, data analysis software, internal utility customer asset data, and external data sources. This involves identifying data flow requirements and providing solutions to ensure timely and accurate billing. This requires the effective integration of AMI and MDMS with existing data systems in the utility.

Information Technology Integration

IT integration is a major participant in the transition from traditional meter reading and revenue protection methods to AMI and comprehensive revenue assurance programs. It's importance is underscored by the level of investment in most AMI programs. Indeed, back-room office applications are a large portion of the total AMI investment, ranging from a low of 5% to over 30%. IT integration is essential to the management and reduction of non-technical losses after the transition to AMI.

IT heavily influences the success of the AMI program and the integration of information systems using new MDMS that is essential for the success of the AMI program. The IT integration plan includes five major systems:

1. Meter Reading
2. Meter Inventory Management
3. Work Order Management
4. Customer Information
5. Revenue Assurance

Integrating these systems is a substantial and complicated task. This requires a high level of commitment from IT stakeholders.

When AMR systems were installed, primarily for savings in manual meter reading, IT integration was not a priority. However, when the data flows (such as tamper flags) became overwhelming, utilities needed applications to manage them. These were often provided through *ad hoc* custom programs developed internally by IT departments.

For this reason, it is advisable to include IT stakeholders from the beginning when making the transition to AMI. The commitment should be in terms of the project, resources, change management, and setting expectations for results. Commitment from IT stakeholders dramatically affects the success of the transition and results in reducing non-technical losses, both at the time of installation and throughout project life.

[57] *Discovering Unaccounted-for Energy with the Revenue Assurance Service*, Patty Seifert, Revenue Assurance Product Manager, Itron. 2007.

Revenue Assurance and IT Integration

The advent of AMI brings a total change to the conduct of revenue protection. If not preceded by AMR, the most obvious change is the elimination of manual meter reading as the primary method of data collection on meter tampering and theft.

Without the benefits of manual meter readers, revenue protection must supplement AMR/AMI with meter data management systems to compensate for the loss of functionality previously provided by meter readers. This involves integrating MDMS into the customer information system. The combination of data from AMR/AMI, MDMS, and customer information system (CIS) can be used to generate leads and profiles for target areas and customers.

Revenue Assurance, Metering & IT business units must come together early, prior to the deployment of AMI, to form a team separate from the deployment itself to develop a Revenue Assurance Transition Plan.

Transition to AMI—Information Technology
Issues that Impact Revenue Protection

- System reliability, data backup and disaster recovery
- Reporting / monitoring capabilities
- End of day vs. real-time 24/7
- Exception handling
- Secure access
- Customer information system integration
- Work order file definitions
- Customer data file management
- Meter reading / billing window ("blackout")
- Test and validation of upload/download processes
- Meter-reading systems integration
- Migration path
- Project size, schedule,and budget

Bob Donaldson, PE, PMP Progress Energy Carolinas Project Manager, Mobile Meter Reading.

Theft and Enforcement

New Methods of Theft

A major risk of realizing the full benefits of AMI for revenue protection is posed when customers learn to divert energy in new, unknown ways. Given historical data from AMR installations, this risk does not appear too great. Also, AMI endpoints have software and tamper sensors that are more sophisticated at detecting theft. Enhancements to back-office systems with new algorithms and heuristics to identify new types of theft are continuously being developed. Nonetheless, most certainly the ingenuity of a few customers will lead to some new types of theft. Distribution utilities need to be alert to new possibilities for theft and take them into account in their revenue protection strategies.

"The western countries and India have treated this as a criminal offence. But crooks always have the ability to keep one step ahead of the theft detection system. They stay in business purely through their flair to overcome any challenge that comes their way. They will find ways to be ahead of any anti-power theft detection system and will try to hoodwink the vigilance wing. Gone are the days of crude mechanical ways to tamper with the meter or divert electricity from main line. The R&D of electricity theft is moving faster than that of the best metering mechanisms, which was revolutionized with the advent of ICs and programmable logic circuits. Sharp minds frame laws and invent technologies; sharper minds find loopholes in it. Now power theft using the remote sensing devices, tampering of crystal frequency of integrated circuits; theft using harmonics, etc. have been developed."[58]

Customer Perception and Motivation

Far from deterring customers from theft, some distribution utilities have reported an increase in occurrences after AMI installation. Once some customers are aware that meter readers are no longer calling, they think that there is less likelihood of being caught. The technical aspects of dealing with advanced electronic metering are no deterrent. There is a wealth of data available on the internet on how to interfere with meters. Even consumption monitoring is not the full answer. Clever thieves know that they should gradually reduce consumption over a period to avoid detection by the relevant "filters."[59]

One new class of customers that are wittier than thieves in the past and have new motivations are "grow operations." These customers—the illegal growers—are motivated not by saving on electricity, but by not being detected as customers. This is a major source of non-technical revenue loss in Canada and parts of California.

AMI can be helpful in detecting theft by this new class of customer. An example from Sacramento, California, is noted in the following quotation.

"Energy theft is not high at all, but we have experienced a significant number of 'grow houses' springing up in the area. We see AMI assisting us in finding these houses from a transformer load perspective—it will tell us that we're sending out X amount of kWh and only billing for Y amount, and alert us to a potential problem."[60]

AMI systems that are deployed at the substation transformer and feeder level are particularly effective in detecting these thefts.

Enforcement

As the attention of regulatory bodies and the public is drawn to energy theft, new and better methods for detecting and finding instances of theft will be called for. AMI has much to

[58] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

[59] OFGEM *Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association*, Version 3 (final). March 15, 2006.

[60] Erik Krause AMI project manager, SMUD

contribute to these methods. AMI offers significant tools to expedite both discovery and resolution of theft cases. It can be used to build intelligent databases for identifying trends and potential factors influencing future theft strategies and targets. This is an ongoing endeavor.

AMI makes more aggressive enforcement programs possible by 1) identifying high-probability targets for investigation and 2) gathering more evidence and constructing more convincing cases.

Meter bypassing can be proved only when it is observed at the time of inspection. The consumer can erase all traces of theft if the inspection is known in advance. This is a significant problem in many developing countries. AMI can help identify customers and locations with a high probability of meter tampering and diversion, thereby increasing the chances to observe theft.

Investigating Power Theft

Utilities often initiate probable cause investigations after a meter reader detects a broken seal or other indications of tampering. The meter reader reports the condition to a supervisor or power theft investigator, who then conducts the investigation. At this point, some utilities will contact their local law enforcement agency and an officer will accompany the utility investigator during the initial investigation.[61]

If the investigator finds evidence of tampering, evidence is collected and reports are prepared. The utility maintains the evidence and provides supporting documentation.

Evidence and Prosecution

Before a utility can file charges against a potential suspect, it must gather the following as evidence, documents, and appropriate statements:

- Tampering devices—These could include straps behind the meter, wires used in a bypass system, or other tampering devices or equipment relevant to the case.
- Meter report—This report shows that the meter was operating correctly when installed and demonstrates how the particular tampering method used would have affected the metering of electricity.
- Witnesses—These are witnesses who provide testimony. They include the meter reader who initially detected the possible diversion, the utility investigator, and the police officer who conducted the investigation.
- Account billing history—This report illustrates the time the theft began and the amount and cost of the stolen electricity.

Without manual meter reading and field service personnel, AMI and MDMS are now expected to provide much of the required documentation for theft investigations. With AMI, this documentation can be much more detailed and present more persuasive cases. For example, most utilities have account billing histories on each account's consumption and billing records on

[61] *Power Theft: The Silent Crime*, Karl A. Seger, and David J. Icove, FBI Law Enforcement Bulletin, March 1988.

a month-by-month basis. AMI provides information on a daily and hourly basis. This is necessary to detect more sophisticated theft techniques, such as "on offs" during the day.

The burden of this documentation is one reason that utilities prosecute only about 10% of cases.[62] The burden can be lessened considerably by using the data that AMI generates and the ability of MDMS to organize it into useable formats for preparing complaints for use by prosecution.

Installation Effect

AMI deployment requires replacing legacy meters with new meters that include two-way communications and diagnostic capabilities. This is a one-time opportunity to significantly reduce non-technical losses due to meter defects, theft, and billing.

> "AMI provides the opportunity for a 100% clean sweep."
>
> Ed Malemezian

Meter Defects

Although theft is a major source of non-technical losses, a significant percentage of non-technical losses arise from factors that utilities can control, especially those related to meter damage, failure, and errors.

"Although, numerous published papers imply that all revenue losses are a result of customer mischief, this is far from true. This project found that, at least in the small industrial and commercial sector, utility operations themselves are responsible for the larger share of lost revenue. Equipment failure, non-malicious equipment damage, incorrect meter constants or 'CT' ratios, meters in need of recalibration, etc. all contribute to revenue loss."[63]

These are largely due to problems with maintenance issues of electromechanical meters nearing the end of their useful life and the tendency of electromechanical meters to run slower as they age. The replacement of legacy electromechanical meters with electronic metering, as part of AMI deployments, should substantially mitigate this source of loss.

The installation of AMI itself, and the replacement of obsolete meters, will contribute greatly to the discovery and remedy of this source of non-technical loss.

A large proportion of meter problems, and nearly all of the failures, will be remedied by a competent AMI deployment that re-installs all meters. Finally, for the life of the AMI system, the AMI-equipped meters will detect and report many types of energy diversion and meter tampering.

[62] Ed Holmes, Senior Consultant, Arnett Industries.

[63] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Some existing meters may be within the permitted accuracy tolerances and still under-register consumption. This is so small that it is not cost-effective to change the meters on an exception basis. However, the AMI deployment replaces every meter anyway, and brings aggregate meter plant accuracy very close to 100%. This benefit will be long-standing because solid state meters have no mechanical wear or friction and do not slow down over time. Sometimes dead meters are found during meter replacements. "Dead meters" are not caught by "no consumption" reports because they usually occur on the percentage of meters that are not yet converted to automated metering.

Inspection

A full AMI deployment provides the opportunity to inspect, find, and correct tampering that has been in place for a long time—100% inspection. However, to be effective, AMR installers must be properly trained and incentivized to take the time required to discover, record, and report tampering.

The entire service entrance facility, not only meters, must be inspected. The importance of inspection to the reduction of non-technical losses is shown in the following statement.

"Utilities that take the time to thoroughly inspect the entire service entrance facility, as well as the meter and meter socket themselves, at the time of AMI equipment installation have the opportunity to minimize otherwise lost revenues."[64]

Some methods of energy theft, such as meter bypass, meters turned upside-down, and meters with drilled holes or adjusted dials, are not necessarily seen by meter readers during their monthly meter-reading cycle visits. Since AMI offers total meter replacement, almost all simple energy theft will be uncovered during the installation of the new meters.

Meter Change-outs

As the volume of AMI-related meter change-outs increases, timely synchronization of meter changes with customer account data becomes essential to help a utility avoid large numbers of billing system rejections caused by incorrect meter assignments. MDMS helps to minimize the number of incorrect and estimated bills that result from the change-out process, thus avoiding billing errors that can contribute to non-technical losses during AMI deployment.[65]

Billing Transition Period

When new meters are installed, a number of data elements must be recorded properly to set up the billing systems. Additionally, new data about meter communications are typically required (such as AMI communication module serial numbers). The installation of AMI offers the opportunity to consolidate databases from multiple sources into a fully integrated MDMS.

[64] Interview with Ed Holmes.

[65] This is particularly important with large-scale AMI deployments that can take from three to five years.

MDMS provides benefits to utilities during AMI implementation by helping to identify and track meter installation problems and verify that data received from endpoints is sufficient for customer billing. If installed as part of the AMI meter installation, MDMS can be used to process data for billing. MDMS can be used for validation, estimation, and editing in the billing process during installation. Interval data provided by AMI systems may have gaps and/or errors. The MDMS system can be used to fill in the gaps and correct the errors in the data.

The AMI installation period offers an opportunity to create customer profiles that compare usage patterns before and after AMI installation. The identification of possible theft in the past is an indicator of theft likelihood in the future.

GIS Mapping

AMI requires that meter asset data is maintained timely and accurately. Meter asset data, including meters and communication modules, must track assets from acquisition to inventory to field installation and provide accurate meter-to-customer and meter-to-network connectivity information. This often requires consolidating and enhancing existing meter applications, including those in meter test, inventory, AM/FM/GIS, and customer information systems. These issues must be addressed at the time the AMI system is installed.

Geographic information system (GIS) mapping during AMI installation provides a valuable resource for revenue assurance. AMI installation offers an opportunity to integrate a GIS system with the customer billing system. This is an effective tool for detecting theft at consumer, distribution transformer, and feeder or substation levels. Analysis of patterns of individual consumption over GIS can help in identifying the sources of theft.

Energy Diversion Program

Utilities can take advantage of the replacement of meters to refresh their energy diversion programs, as well as public awareness of the issues and penalties.

Distribution utilities that have some type of revenue protection program in place can update their program and institute more aggressive programs using a combination of the AMI, MDMS, and teams of newly trained field inspectors.

For distribution utilities that do not have an energy diversion program, AMI installation is an opportunity to institute one at low cost.

AMI Planning and Transition

The revenue protection department staff should be included in the AMI project team from the beginning of the planning process. These individuals can offer valuable insight on many pertinent issues, ranging from a customer's behavior to billing (the integration of databases in the MDMS) to collection. Most importantly, they have the experience to help train meter installation teams and monitor the testing and installation of the meters themselves. They are an important part of the transition to AMI. Their participation can contribute greatly to the realization of potential savings from AMI and the reduction of non-technical losses.

The transition itself—replacement of meters, analyzing customer profiles, testing, system development, algorithm development, and customer profiling—probably has the greatest impact on revenue security and the reduction of non-technical losses.

3
CHAPTER 3

AMI Technologies to Detect Non-Technical Losses

AMI offers many technologies for the detection and reduction of non-technical losses. These technologies can be divided into two main categories, hardware and software, as outlined in the following insert.

Hardware – metering technology

- Meter accuracy
- Tamper detection
- Remote testing diagnostics
- Remote connect/disconnect

Software-based applications and tools

- Meter data management systems
- Statistical analysis
- Geographical information systems

These technologies can be used alone or, preferably, in combination with one another for enhanced effectiveness and manageability.

In this chapter, these technologies will be discussed in the context of their relevance to non-technical losses.

Importance of AMI Technologies to Detect and Reduce Non-Technical Losses

The relevance of the technologies for the detection and reduction of non-technical losses is evidenced by the functions and uses that utilities consider most important as part of overall AMI deployment.

As part of the FERC report[66] on demand/response and advanced metering, FERC staff conducted a survey of utilities.[67] Respondents were asked how they used their systems and which functions

[66] Section 1252 (e) (3) of the Energy Policy Act of 2005 (EPAct 2005) requires FERC to prepare a report by appropriate region that assesses electric demand/response resources.

[67] *Assessment of Demand Response and Advanced Metering Staff Report*, Docket AD06-2-000. FERC. August 2006. In preparing this report, Commission staff developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering

are provided by the AMI systems. Specifically, the FERC survey asked organizations that have installed AMI systems[68] to identify which of the following possible AMI features they used:

- Remotely change metering parameters
- Outage management
- Pre-pay metering
- Remote connect/disconnect
- Load forecasting
- Reduce line losses
- Price responsive demand/response
- Enhanced customer service
- Asset management, including transformer sizing
- Premise device/load control interface or capability
- Interface with water or gas meters
- Pricing event notification capability
- Power quality monitoring
- Tamper detection
- Other

The most often reported functions were "enhanced customer service," and "tamper detection." Figure 3-1 shows the results of the FERC Survey.

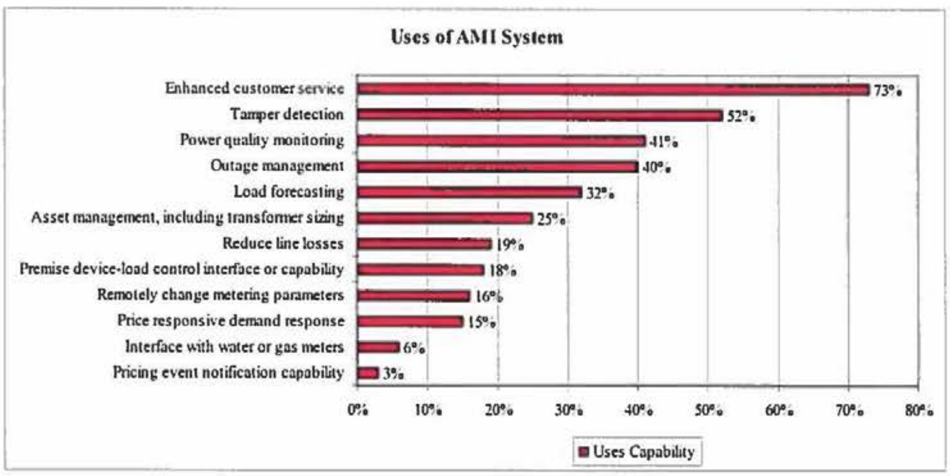


Figure 3-1
Uses of AMI System

Survey (FERC Survey) requested information on a) the number and uses of advanced metering and b) existing demand/response and time-based rate programs, including their current level of resource contribution.

[68] For purposes of this report, Commission staff defined "advanced metering" as follows: "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

The identification of these uses of advanced metering by utilities points to a number of areas related to the detection and reduction of non-technical losses. Recognition of these functions indicates the importance of non-technical losses to utilities as part of overall AMI programs. At minimum, it shows that AMI must deliver enhanced customer service and tamper detection:

Enhanced Customer Service: The ability to offer ultimate customers the choice of bill data, additional rate options such as real time pricing or critical peak pricing, verification of an outage or restoration of service following an outage, more information to address a customer concern over an electric bill, reduced bill estimates when a meter read is not available, opening or closing of an account due to customer relocation without requiring a site visit to the meter(s), and/or more accurate bills.[69]

Tamper Detection: The ability to detect the possibility that a revenue or billing meter has been tampered with, and to indicate a potential energy theft in progress, to be further investigated by the utility.

Theft at the Meter

There are two types of theft at the meter that contribute to non-technical losses: bypassing the meter and tampering with the meter itself.[70] The various ways in which this theft is done are listed in the following two inserts.

Installation Tampering

Line-side taps
- Weather-head
- Service entrance conductors
- Underground
- Switchgear / buswork / troughs

Bypass
- Jumpers in meter socket
- Close bypass device

Instrument transformer installations
- "Re-wiring"
- Shorting of current transformers

Meter Tampering

Internal to the meter
- Adjustment screws—one time
- Register tampering
- Magnetic circuit alteration
- Electrical alteration
- Dial tampering—Recurring

External to the meter
- Magnets—RC
- Hole in cover / disk "pinning"
- Upside-down meter
- Stolen meter

Internal physical tampering with the meter itself appears to be a less popular method of stealing energy than bypassing the meter or using diversionary taps installed ahead of the meter in the supply wiring.[71]

[69] AMI—through remote reading—allows for faster, more accurate accounts, reduces discrepancies, and through remote connect/disconnect allows for faster, more timely activation and deactivation of accounts. This translates to more revenue and fewer disputes.

[70] AMR Tamper Detection - The Good, the Bad, and the Possibilities, Ed Malemezian

Installation tampering and meter tampering should be kept in mind while considering the technology features described in this chapter.

Technologies

The uses of AMI technologies to support revenue assurance programs were discussed in the previous chapter. In this chapter, we shall focus on describing the technologies in terms of their characteristics and functionality.

Meter Features

Among the meter features used in AMI systems, those that are important for detecting non-technical losses are listed in the following insert.

[71] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Meter Standards and Features

Important for Detecting Non-technical Losses

Institute of Electrical and Electronics Engineers (IEEE)/ American National Standards Institute (ANSI) Standards

- IEEE 1701/ANSI C12.18 (1996)
  Protocol Specification for ANSI Type 2 Optical Port
- IEEE 1377/ANSI C12.19 (1997)
  Utility Industry End Device Data Tables
- IEEE 1702/ANSI C12.22 (1999)
  Protocol Specifications for Telephone Modem Communications

High-accuracy internal clock

Communications

- two-way communications
- communications functions that can be installed without disturbing metrology

Measurements

- power quality measurements: outage detection and duration; phase loss, sag, and surge detection
- storage capabilities for multiple sets of readings
- event log with circular memory buffer to store up to 100 events
- measure and display active energy delivered, received or net, or any two registers from delivered, received and net (kWh and kVAH)

Prepayment

- prepay functionality, including varying deductions per time-of-use scheduling, configurable emergency credit, and audible low-credit alarm

Security

- measurement technology that is immune to magnetic tampering
- record of programming changes, power outages, number of demand resets
- reverse disk rotation

Disconnect/connect

- disconnect switch controlled via software
- remote disconnect/reconnect switch

Tamper Detection

- tamper indications that can be communicated regularly through the communications system
- indicators include meter inversion, meter removal, and reverse energy flow
- tamper-resistance features that measure energy even if the meter is inverted and detecting when the meter is removed from a live socket
- increments a counter each time the meter senses reverse power flow
- power removal tamper (increments a counter each time the meter is removed from a live socket)

Hardware: Meter Requirements

Meter requirements will be discussed under four major headings:

1. Meter accuracy
2. Tamper detection
3. Remote testing and diagnostics
4. Remote disconnect / connect

Meter Accuracy

The accuracy of metering data is becoming increasingly important as advanced metering provides data that are integrated across many utility functions. The trend towards solid-state meters capable of delivering information for real-time use has increased both the visibility and importance of meter accuracy to distribution utilities, customers, and regulators. The increasing inaccuracy of legacy electromechanical meters as they age contributes to non-technical losses.

To evaluate the best metering platform for AMI, one utility performed a statistical study of electromechanical meter accuracy.[72] The results were as follows:

1. A thorough statistical analysis of electromechanical meter accuracy found that 20% of electromechanical meters have a high likelihood of under-recording usage by an average of nearly -0.8% (or 99.2% meter accuracy), with significant levels of variability in meter accuracy.
2. Service location (environmental factors), manufacturer meter serial number, and meter age were found to be reliable predictive factors of electromechanical meter accuracy.
3. The "accurate life" is about 25 years for most electromechanical residential meters and about 20 years for most electromechanical demand meters.
4. The volume of in-service meters recommended for replacement was highest for meters purchased from the late-1970s to the mid-1980s. Over 32,000 in-service meters recommended for replacement had an unknown purchase year and an average kWh composite meter error of -1.13%.

Meter Accuracy

Mechanical meters, in addition to being less accurate than solid-state electronic meters when new, fail as they age. Many meters eventually fail completely and register zero-use. Such failures often go undetected for a period of time because they are assumed to be caused by customer vacancy. Eliminating slow meters and other metering issues involving "lost and unaccounted for" energy use will result in accurate bills and assign payment obligations to those customers who use the energy rather than to all other customers.

Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, SGD&E before the CPUC, March 28, 2006.

[72] *Metering Accuracy, Solid State Metering and the Electric Utility Enterprise Transformation*, Dave Mundorff, Entergy Corporation. September, 2005.

Tamper Detection

Tamper detection features that are important to AMI include the following:

- Reverse energy flag / reverse energy register
- Tilt switch
- Meter inversion
- Blink counter—no power to meter
- Magnetic sensors and diagnostics

These tamper detection features are described in the sections below.

Reverse Energy Flags
Reverse energy flags detect meters that have been turned upside down. In addition to the flag, some meters capture the reverse energy in a separate register. Other meters simply add reverse energy to forward energy, thereby accumulating total consumed. Theft is detected when the total no longer matches the meter dials.

Tilt Switches
Tilt switches detect meters that have been tilted from the normal position, usually around 50° to 70°. Tilt switches are prone to give false indications from vibrations. Meter removal is inferred when the tilt switch closes and a power outage detected after short time delay. Tilt switches, along with the outage detection, provide a reliable indication of meter removal. However, it must be noted that meter removal does not necessarily mean that tampering has taken place.

Meter Inversion
Meter inversion is inferred when meter removal has been detected.[73] In this instance, the tilt switch stays closed and power is restored, providing a reliable indication that the meter is running upside down. This also can generate a reverse energy flag.

Blink Counters
Blink counters measure increments for each interruption detected. A repeated number of interruptions can indicate tampering.

Magnetic Sensors & Diagnostics
Site and meter diagnostic sensors on solid-state meters (solid-state meters only; not meters with communication interface add-ons) detect meter wiring, instrument transformer, voltage, and current balance problems. Meter diagnostic flags detect internal meter malfunctions and tampering.

Reverse energy flags have proved effective in tamper detection. However, AMI generates a very large number of flags that must be sorted out. In many cases, the number of flags is overwhelming. Some of the flags are "false;" for example, magnet sensors generate many false flags.

[73] When the meter is pulled out of the socket and plugged back in upside down, the meter runs backwards and the kWh register goes down instead of up. The user leaves the meter inverted for a number of days to shave usage off the bill, and the meter is then reinstalled before a meter reading.

To be effective, tamper indicators must be filtered to spot trends and provide reliable comparisons.[74] Blink counts and outage flags must be compared against neighbors. Regular meter work, emergency work, maintenance, and repair work must be backed out of data on meter tilts, removals, and power outages. In other words, a system solution is required for these features to be utilized effectively by revenue protection departments.

Tamper Detection Features

Meters shall be able to:

- detect removal from its socket and generate a tamper event before it loses ability to communicate with the communications network
- detect voltage at the load side when the disconnect switch in the meter is open (for the purpose of detecting meter bypass) and generate a tamper event
- detect physical inversion and generate a tamper event
- detect physical tampering, such as, seal tampering, meter ring removal, case / cover removal, etc. and generate a tamper event
- transmit and locally log the following information (at a minimum) for each tamper event:
    1. Event Timestamp
    2. Tamper status (event type)
    3. Meter ID
- communicate tamper events to the Data Center Aggregator as soon as they occur (when possible)
- send meter tamper events with a higher priority than normal status messages
- store tamper events and transmit them when meter communications are re-established (if the meter is unable to communicate at the time the tamper event is detected)
- distinguish initial installation events and re-energize events (i.e. after an outage) from meter removal and reinstallation (potential tampering) to avoid transmission of non tamper related events.
- store tamper events until they are flagged for deletion once they have been successfully transferred to the Data Center Aggregator and 45 days have passed.

AMI Preliminary System Requirements, SCE. June 2006.

Testing and Diagnostics

Since AMI systems allow the reduction or elimination of meter service personnel and on-site visits, remote diagnostics are used to replace the meter reader's "eyes in the field."

Diagnostic features located in the meter typically provide measurements of parameters such as the following:

- Polarity
- Voltage deviation

[74] AMR Tamper Detection—The Good, the Bad, and the Possibilities, Ed Malemezian

- Inactive phase current
- Phase angle displacement
- Current imbalance
- Reverse energy

Service scan diagnostics read data on these parameters and current conditions at meter locations.

Results are reviewed by engineering staff who initiate an investigation, issue an instruction for meter change-out, or an investigation of the distribution line.

Service scans can discover open voltage test switches, current test switches left shorted, failed wiring on the meter harness from test switch to meter base or incorrect initial wiring, failed voltage transformers, and open distribution line fuses. All of these, including meter failure itself, contribute to non-technical losses.

The requirements for testing and diagnostics for meters and data center aggregators are shown in the following insert.

Testing and Diagnostics

Meter shall be able to:

- support a remotely or locally initiated meter test for communications connection status
- support a remotely or locally initiated meter test for energized status
- support a remotely or locally initiated meter test for load side voltage
- support a remotely or locally initiated meter test for disconnect switch status
- support a remotely or locally initiated meter test for internal clock time accuracy
- return results for all remote or local meter tests within 60 seconds
- Neighborhood Aggregator shall permit remote:

  1. status report (up / down)
  2. diagnostics
  3. link status report
  4. communications event log retrieval

Data Center Aggregator shall be able to:

- provide comprehensive remote testing and diagnostic capabilities for each system component (communications and meters) based on a (periodic) schedule or on demand. Remote testing and diagnostic alarm messages are to be considered high priority.
- remotely test meters for communications status, energized status, load side voltage and switch status on-demand.
- remotely test communications with external third parties.
- identify the probable cause of a communications failure within the AMI communications network.
- provide mechanisms for remotely correcting system/component problems, which at a minimum shall include the ability to remotely recycle (or restart) a component.
- log the results of all remote testing and diagnostics activities and any automatic actions taken based on those results.
- make the results of all received alerts and remote testing and diagnostic results available to authorized IT systems (e.g. MDMS, CSS, Work Order Tracking, etc.).
- have configurable alert levels and notifications based on the severity of a problem detected and the number of endpoints affected.
- classify specific testing/diagnostic results to either require or not require human intervention (configurable) in the determination of issuing trouble reports.
- detect if any network components are not responding within the following intervals based on the number of meters affected. (Estimate only; different network topologies will result in different values.)

  A) < 200 meters - next read.
  B) 200 - 1000 meters - within 6 hours
  C) 1000 - 5000 meters - within 1 hour
  D) 5k - 20k meters - within 15 minutes
  E) 20k - 50k meters - within 1 minute

AMI Preliminary System Requirements, SCE. June 2006.

Remote Disconnect / Connect

With solid-state meters being deployed as part of AMI systems over entire service territories, remote connect/disconnect features are attractive from service, operational, and economic points of view. The key driver for this change is that meter providers can integrate the disconnect/connect switch into the solid-state meter.

Remote connect/disconnect switches have traditionally been installed on electric meters for customers who either were consistently late on paying their electric bill or that lived in an area where people moved more frequently.[75] These classes of customers have a high incidence of non-technical losses with respect to non-payment of bills and errors in billing due to timing of disconnects / connects (stop time for one customer; start time for another).

[75] This is not an insignificant class of customer. For example, customers in SCE's service territory move at a rate of one in every four customers per year. (Paul DeMartini, Director AMI Program)

Remote Connect/Disconnect Features

Meter shall be able to:

- accept scheduled service disconnect/ reconnect
- remotely disconnect/ reconnect on demand
- remotely disconnect/reconnect according to utility pre-configured rules
- detect duplicate service disconnect/ reconnect events and ignore the duplicate events (e.g. Meter is already on -- reconnect event accepted with no action taken)
- cancel or update/reschedule scheduled disconnect/ reconnect events prior to their completion
- send a meter read and acknowledgement to Data Center Aggregator upon a successfully completed or failed electric service disconnect/ reconnect event
- enable an SCE Employee working on-site at the customer premise to be able to physically operate its service disconnect/ reconnect switch at any time. 24 hours, 7 days a week, 365 days a year
- support an external authorization/ authentication routine (i.e. by remote systems or field tool) to enable only active and eligible SCE employees to operate its service disconnect/reconnect switch on-site at the customer premise
- allow authorized SCE employee (while on-site at the customer premise) to operate the service disconnect/reconnect switch immediately (regardless of interval) or to schedule a connect/ disconnect for a future interval
- log date/time and status of attempts to operate the service disconnect/reconnect switch remotely or on-site at the customer premise. Log entries will include requesting user or system identity and authorization status
- remotely disconnected/reconnected on demand and have acknowledgement received by requesting system within 1 minute of request being initiated
- allow a reconnect event to occur following a disconnect event only after a configurable amount of time (e.g. at least 1 to 2 minutes) has elapsed since the disconnect event.
- Note: Should a disconnect event and reconnect event be scheduled to occur for the same meter on the same day, Meter shall log the events and automatically provide an on-demand read to the Data Center Aggregator without operating the disconnect/reconnect switch

AMI Preliminary System Requirements, SCE. June 2006.

Software-based Applications and Tools

To be effective, AMI tamper indicators need to be filtered to spot trends, outliers, and provide for reliable comparisons. Blink counts and outage flags need to be compared against neighbors. Normal meter and trouble work need to be backed out of meter tilts, removals, and power outages. Custom algorithms and a formal process are required to look at trends. Energy consumption needs to be compared—by individuals and by groups.

To be most effective, AMI data needs to be combined with the following:

- Class of customer
- Geographical information
- Normalization for weather, occupancy, and other similar factors
- Customer's past history—family, friends, and other businesses
- Other utility usage—gas, water, cable
- Experience

Software-based applications and tools must be used to analyze the data that are delivered by AMI metering and communications technology to utilities—revenue assurance departments in particular. There are three major categories of software-based applications and tools that are necessary for AMI to effectively detect and reduce non-technical losses and maximize its impact on revenue:

1. Meter data management systems
2. Statistical analysis
3. GIS—at time of installation and for identifying locations for abnormal behavior

Meter Data Management Systems

Advanced metering delivers frequent interval data, which greatly increases the amount of information a utility will have about consumption. The volume, frequency, resolution, and type of data (for example, interval demand data, voltage, outage events, and meter tempering indications) delivered by AMI from meters are vastly different from manual meter reads and mobile (drive-by) meter-reading systems.

MDMS is used to manage the large volumes of meter data generated from AMI systems. MDMS is the software that accepts data collected from an AMR/AMI system, stores the data, and forwards the data to utility systems such as billing. MDMS is an essential tool for utilities that may have tens or even hundreds of thousands or millions of meters generating data that are gathered in multiple ways.

Data Collection and Analysis

While AMI monitors customer power consumption , MDMS uses the data collected for statistical analyses that generate standard reports, such as Hi/Lo reads with statistical process control charts, multi-day bad meter reads, zero usage day with non-zero average, and custom meter groups. These can be used to identify customer load changes that may be related to meter theft.

MDMS is used to develop actionable intelligence for use in revenue protection programs. MDMS receives revenue protection flags from the meters and compares them with usage trends, outage information, and service order/field work to determine which are actual revenue protection issues and which are false positives.

By relying on a central repository of historic meter data, analytics can pinpoint usage patterns that might indicate meter defect, meter tampering, or theft of service. If a customer's energy usage remains abnormally low during heat waves, cold snaps, or before and after outages, then the meter might be malfunctioning. If more energy is flowing past distribution points than is being billed for, then it's possible that someone is stealing service. Without meter data management, this type of revenue-assuring analysis is nearly impossible.

MDMS is used to validate data against theft indicators, automatically initiating appropriate alerts and tracking responses. MDMS is used to set threshold levels for usage on a premise-by-premise basis.

Integration with CIS and Billing Systems

MDMS automates and streamlines the identification of accounts with potential theft, thus reducing the time and expense of unnecessary site visits by revenue investigators. With visibility into the probable condition of each meter in the system, revenue investigators can monitor accounts systemwide without additional investments in time, resources, meter seals, locks, and other security gadgets.

For optimum performance of AMI-supported applications such as tamper or leak detection and processing of on-demand and off-cycle reads, MDMS should be integrated with utility functions carried out in CIS, billing, and other systems such as load control. Customer service personnel, for example, should have access to daily and interval read information provided by AMI to respond to billing inquiries, process service cancellations, and perform other functions. This will require development of new screens for integrating and displaying data and can be time-consuming to develop and test.

Interestingly, MDMS identifies meter failure before the billing cycle, thus avoiding billing errors on both the hardware and software components of AMI, both contributors to non-technical losses.

Integration into AMI and Enterprise

To realize the benefits of revenue protection, including meter tempering and illegitimate consumption, AMI must be capable of providing the data required to detect theft. This means that MDMS should be able to ingest and analyze the AMI data to initiate, track, and close-out follow-up work orders via the utility's work order management system with respect to meter installations, change-outs, communications interfaces, maintenance, and upgrades.

MDMS is an integral and essential part of AMI with respect to developing solutions for non-technical losses.

MDMS and the AMI Technology Evaluations

Conceptually, the meter module hardware, communications infrastructure, AMI head-end system, the MDMS, and the integrations with a utility's existing back-office systems should be thought of as one end-to-end integrated and seamless solution that, only together, can enable the utility to achieve the expected benefits of AMI. Hence, it is beneficial for a utility to assess the capabilities it requires of an MDMS and determine how the AMI data will touch the utility's existing systems, the same time when evaluating AMI technologies and developing an AMI business case.

Meter Data Management System, Tram, Hahn and Ash, Chris, Enspiria Solutions. August 29, 2005.

Statistical Analysis

AMI generates a wealth of data. The shear volume of this data demands that software applications be developed to perform statistical analysis for it to be useful for detecting and correcting non-technical losses. As meters become more sophisticated (solid-state meters flag many meter-tampering techniques automatically in real time), so do thieves. Software applications can be used to strike the balance in favor of revenue assurance.

Some of the more prevalent software applications and techniques for statistical analysis are described in the sections below.

Customer Profiling

Load profiles and data mining techniques can be used to minimize non-technical loss activities. Load-profiling methods and data-mining techniques can be used to classify, detect, and predict non-technical losses in the distribution sector due to faulty metering and billing errors. They provide a framework for the analysis of customer behavior.

Load Profiling

The key to this approach is the recognition of significant deviations known as outliers in the customer behavior patterns. The method of doing so involves modules including the load profiling and non-technical losses analysis in processing large volumes of data relating to customers' electricity consumption patterns. The load profiling module includes clustering customer behavior according to the loading conditions identified and allocating the clustered load profiles to the respective categories based on the customer and commercial indices. The non-technical loss analysis module uses the representative load profiles as a time series model and detects the outliers based on the set up benchmark based on abnormal and normal behavior patterns. The detected abnormalities due to non-technical loss activities are used as a reference to develop a forecast model on non-technical loss profiles with other external features.

Framework Analysis of Customer Behaviour due to Non-Technical Losses in Malaysian Electricity Supply Industry, Anisah Hanim Nizar, ITEE. July 17, 2006.

Interval Metering

Since AMI systems can support frequent readings and high data resolution, interval metering is possible. This allows the utility to study consumption patterns for anomalies that may indicate metering problems.[76]

Some "smart meters" measure consumption in intervals of an hour or less. The resulting increase in data points (from 4 or 12 per year to 8700+) allows utilities to develop highly sophisticated customer profiles. This information can be used to analyze consumption patterns at sites where theft is suspected.

Utilities can develop and compare profiles within the billing system. However, the process would likely slow down bill production. A far more efficient solution lies in the use of an out-of-the-box business intelligence application that extracts data from a billing or meter data management application, then builds and compares profiles in a non-production environment.[77]

A list of significant deviations based on interval data provides targets for investigation. Deviation from a profile norm is a good indicator of theft, sufficient to merit investigation.

Distribution Analysis

Metering cannot detect bypass-tapping supply before it reaches the meter. For most utilities, bypass is the primary theft method. Bypass on underground lines can go undetected for years.[78]

Using data from smart meters, distribution management systems can be used to reach a solution to this problem. A distribution management system can correlate energy meter readings with available feeder load data to identify feeder loss characteristics and a profile. Utilities can use these to create a ranking of the worst performing distribution feeders. This system perspective of feeder loss allows a utility to address load theft where it is greatest. Also, smart-meter-provided power quality data (for example, voltage, current, and power factor) can assist in determining the feeder section losses.

This analysis helps narrow the source of a loss to a relatively small number of sites. Looking at the accounts associated with those sites, along with information on ownership and purported use, points to the likely location of the theft.

Trends and Comparisons

Custom algorithms and a formal process are required to identify trends. Energy consumption needs to be compared by individual customers and by class of customers. Comparisons are made by combining AMI data with the following:

[76] Load profile analysis using monthly meter readings is impractical for detecting energy theft. *Algorithm for Detecting Energy Diversion*, EPRI. 1991.

[77] New metering & grid applications improve theft detection, Adrian Patrick, PhD, Automatic Meter Reading Systems, Oracle, Utilities Global Business Unit. July 31, 2007.

[78] When the power is used for illegal, high-consumption "growing" and drug-manufacturing purposes, losses can be substantial.

- class of customer
- geographical information
- other utilities—cable, gas, water
- customer history and behavior patterns

Statistical Algorithms

MDMS uses a series of statistical algorithms that, in essence, perform the same initial screening and analysis work usually performed by a team of utility revenue assurance experts, only in a more consistent manner and at a much lower cost.

MDMS identifies revenue leakage by applying these algorithms, along with revenue assurance investigation best practices, across multiple utility internal data sources (CIS, MIS, WFMS) and appended with external data sources (SIC, zip +4, credit score, weather) to create a list of suspect accounts. The suspect list is a prioritized list of premises or accounts with reason codes and a weighted revenue recovery valuation of each opportunity. A suspect list is provided to the utility's revenue protection investigation team on a periodic basis for field investigation and subsequent actions (for example, customer contact, back-billing, mediation, and negotiations).

Geographical Information Systems (GIS)

GIS mapping and integration with customer databases is used to identify and locate consumers on the geographical maps being fed from the distribution network. There may be cases where an electric connection exists, but is not in the utility's record. There may be instances of unauthorized connections or unrecorded connections. On the other hand, there may be instances where a connection is recorded, but does not exist physically at the site.

GIS provides utilities with accurate data and useful information to manage their assets and customer base. GIS coupled with GPS can assist in maintaining data integrity and recovering "lost revenue."

GIS should be used to provide aerial photographs or maps of the area, with spatial references to the physical and electrical distribution network, metering points within buildings, and buildings without meters installed. All network and customer documentation should be linked, and all assets in the area should be mapped. Widespread access to relevant data should be available through a web-enabled client-server.

Installation of AMI at the substation level helps to target areas where technical and, more importantly, non-technical losses are problematic.

Results from analysis using GIS-enabled tools can be used to focus energy audits by revenue protection teams. In the case of major retail and industrial customers, technical specialists can prioritize locations for on-site audits, checking meters and installations, instrument transformers, metering and billing constants and ensuring that no by-passing is taking place.

GIS is an ideal integration platform for meter data, supervisory control and data acquisition (SCADA), and customer information systems, as shown in Figure 3-2.

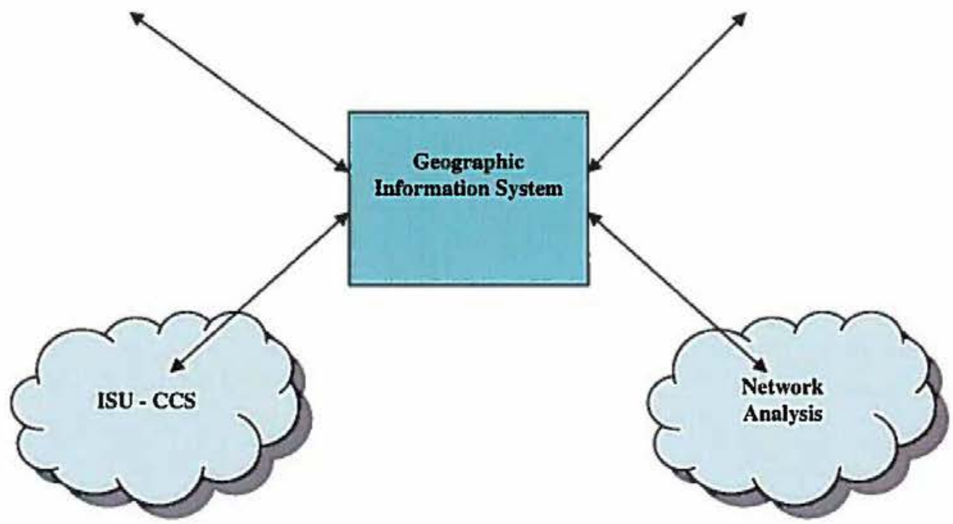


Figure 3-2
Geographic Information System

Tasks for which spatial data can improve processes are meter reading (including rollout of AMI systems), credit and collections, customer analytics, billing, and customer communications. An enterprise GIS fully integrated within the mainstream of utility IT infrastructures helps utilities understand customer behavior and their transactions.[79]

GIS can help visualize significant mismatches between known usage and actual consumption using GIS advanced network modeling.

Many utilities consider the GIS system as the "ultimate" source database, acting as a common repository for all enterprise applications. This is accomplished by integrating GIS technology into the mainstream business operations of the company.

[79] *GIS Enhances Electric Utility Customer Care*, An ESRI ® White Paper. May 2007.

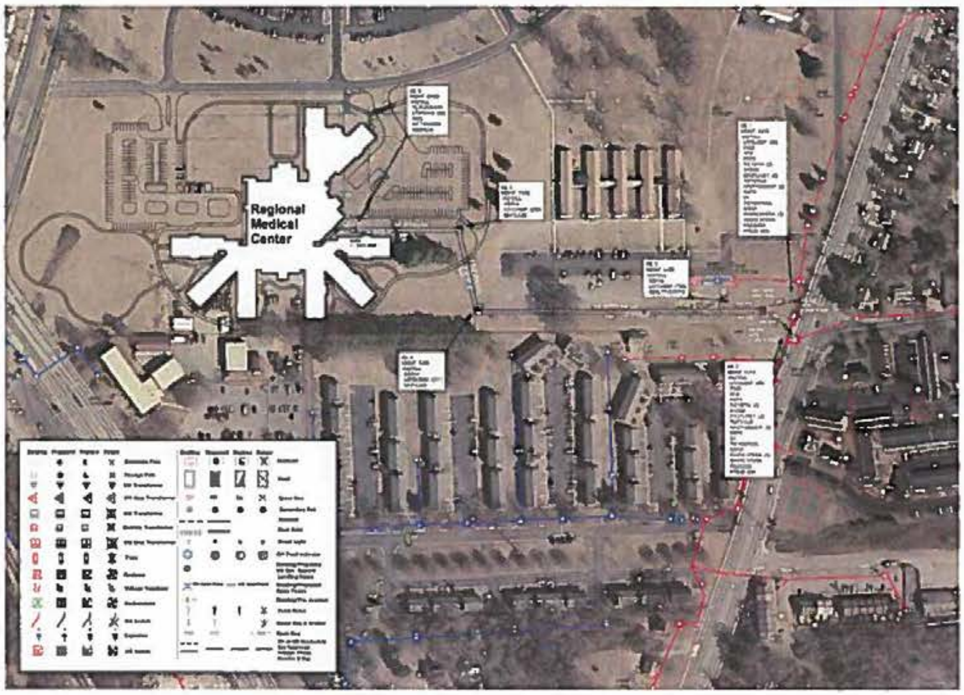


Figure 3-3
GIS Aerial Map

GIS Integration Functional Requirements

The functional requirements for integrating AMI with GIS are as follows:[80]

- Complete automation of the distribution network is not possible. It would require implementation of SCADA/DMS at every section of distribution system, which is prohibitively expensive. Hence, getting real-time data from SCADA/DMS for all parts of distribution network is not possible. This problem can be overcome by the integration of GIS with AMR/AMI.
- Normally, the metering data from AMR/AMI are available to billing personal. However, these data are not available to other employees directly. Once integrated with GIS, every employee can have access to data through multiple GIS applications.
- AMR/AMI data are helpful for detecting losses in the distribution system. Using GIS, losses can be viewed geographically and analyzed. This analysis can be used to map areas where there is a high incidence of theft or other distribution system losses. These maps can be used to develop predictive models (Figure 3-3).
- Energy consumption information can be used to build databases of real-time and historical (periodical) demand and energy data at the source (for example, feeders and

[80] A detailed discussion of this subject can be found in *GIS integration with SCADA, DMS & AMR in Electrical Utility*, Uday D. Kale and Rajesh Lad. Reliance Energy Ltd., Map India. 2006.

DTs) and load (consumers) levels. This information can be used to build network simulations of loading conditions and for load forecasting. These databases can be helpful in developing profiles, behavior models and incidence indicators for theft.

- With the data received from AMR/AMI, GIS tools can be used for energy auditing in a geographic context, which is useful in specifically identifying particular areas suffering high energy losses.
- The correct assessment of technical and non-technical loss components needs correct metering data. This information can be provided over the GIS platform. GIS tools can be used by network analysts to identify and display spatially feeders, transformers, and distribution areas having high-energy losses (Figure 3-4).

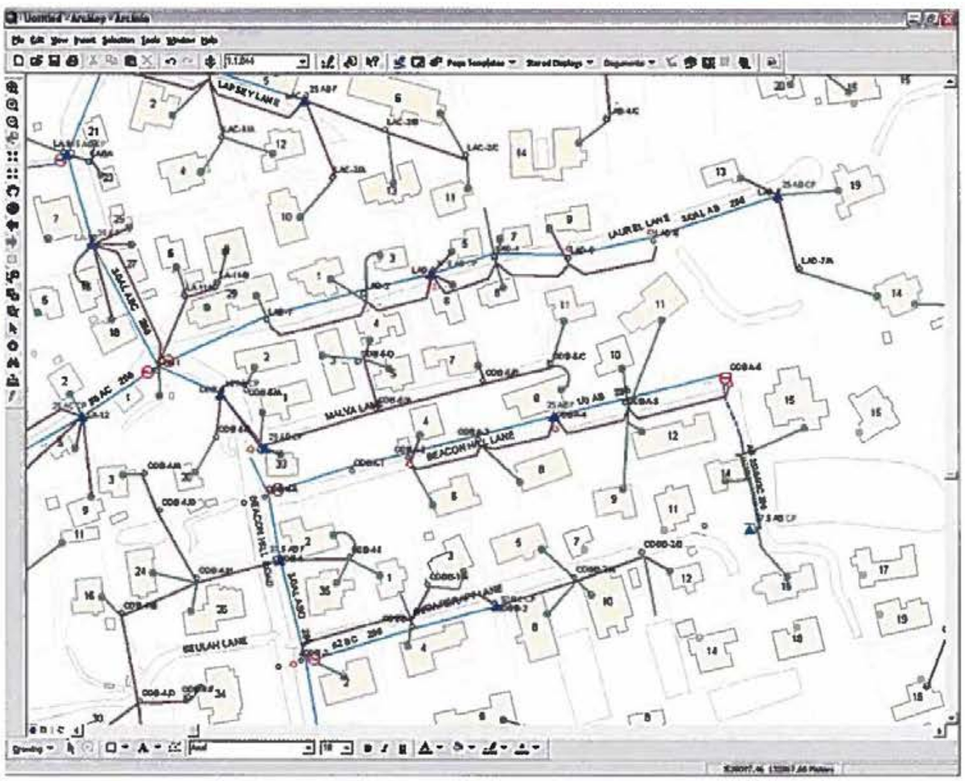


Figure 3-4
GIS High-Energy Loss Map

GIS and Field Inspections

GIS mapping of AMR/AMI data has been used successfully to identify locations for field inspections. These have led to high "hit rates" for the detection of meter tampering. An example of GIS for field inspections is shown in Figure 3-5.[81]

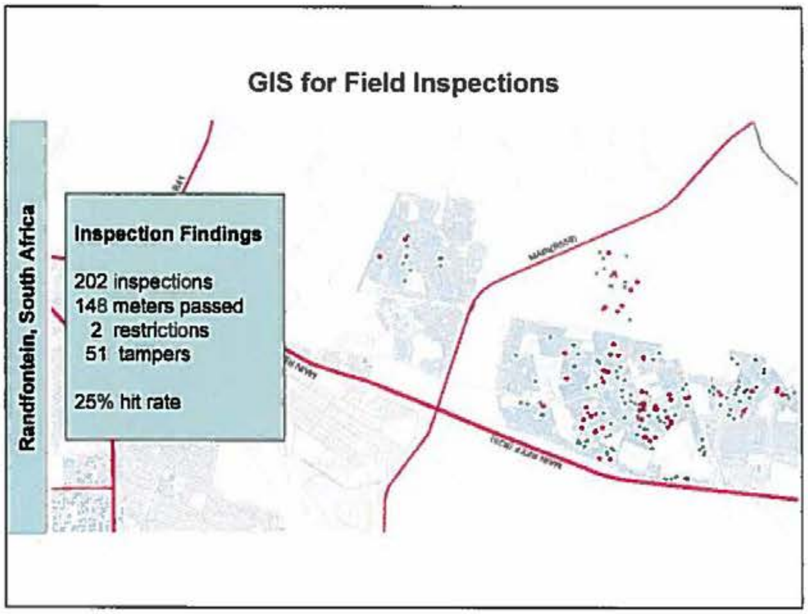


Figure 3-5
GIS for Field Inspections

Analyzing Theft at Substation Level

With integrated GIS, it is possible to access exactly the geographical areas where theft is most prevalent, areas where theft can be preempted by enhanced levels of vigilance, and areas where revenue assurance should step up its efforts and be more accountable for results. Typically, the area served by a substation is only a few square kilometers in size, facilitating the implementation of corrective measures.

GIS can play a major role in identifying areas of the distribution network where theft is likely. Identifying potential theft in the distribution network is accomplished by the integration of billing and SCADA systems on a GIS platform.[82]

[81] *Resource & Revenue Protection as a Tool for DSM*, Christophe Viarnaud, Actaris and Gregor Schmitz, BreakThru Consulting.

[82] *Role of GIS in Preventing Power Pilferage*, Dr. Nagesh Rajopadhyay, Manish Arora and P. Madhusudhan, Info Tech Enterprise Limited, Hyderabad. GIS Based Distribution System Planning, Analysis and Asset Management Training Program, USAID.

SCADA systems continuously collect real-time readings of all electrical parameters at monitored points on feeders.[83] The system obtains information on the status of various switching devices (for example, circuit breakers, switches and isolators) and transformer parameters (for example, tap position).

When electronic meters are installed at the customer level, they can be equipped with an interface for communications with the SCADA system, using an industry standard protocol. Meter readings can then be used both to monitor the load and to detect attempts to tamper with the meter. As soon as a tamper is detected, the meter/consumer can be tagged on the GIS system. The information can then be passed on to revenue assurance for physical checks and corrective action.

PSS/Engines™ must be interfaced with GIS for network analysis and optimization. A data model must be created in GIS for geographic locations as well as for the network.

Steps for the system and database integration and GIS mapping:

- Interface of billing system to GIS (GIS application software reads external relational database management system [RDBMS] of billing system).
- Entry of billing-related information to customer database.
- Identify the total power delivered from the substation (P-total) and the total power billed to the customer (P-billed).
- Calculate network power loss (P-lost) with network analysis tools and map network data in GIS.
- Calculate power theft (P-theft) or commercial loss at the substation level. Formula: (P-theft) = (P-total) - (P-billed) - (P-lost).
- Plot the results on GIS.

A similar analysis can be made at the transformer level, provided that the meter is installed at the transformer and a reading is available.

A link must be maintained between the external billing database and the GIS database. Billing data must be populated simultaneously in the external database and the GIS database. After the entry of meter data at a substation level, the system can be asked to evaluate the total commercial loss.

[83] These parameters include voltage, angle, power factor, active power, reactive power, and energy.

Implementation of AMI Technology

The way in which an AMI installation is planned and executed has a major impact on its success in ensuring that the technologies are installed properly, detecting meter tampering and by-pass at the time of installation and setting up and integrating the data management systems and GIS platform for revenue assurance programs in the future. It must be recognized that installation of hardware and software is as important as the technologies themselves for realizing the benefits that AMI offers for the detection and control of non-technical losses.

Successful implementation of AMI technology requires the participation of experienced revenue assurance staff at all stages of the process—planning, procurement, installation, and integration into the utility enterprise systems. These individuals have valuable insights into the transition from manual to remote meter reading and auditing. They have much on-site experience to share for meter replacement. Moreover, they understand the need for comprehensive data management tools. Most importantly, revenue assurance offers quality control for the realization of the operational savings that provide the economic justification for many AMI programs.

4
CHAPTER 4

Overview PPL Electric Utilities

PPL Electric Utilities is the regulated electricity and gas subsidiary of PPL Corporation. The annual revenues and assets of PPL Corporation are \$6.9 billion and \$19.7 billion, respectively. PPL Electric Utilities serves over 1.4 million customers over 10,000 square miles in Central Eastern Pennsylvania (Figure 4-1).

PPL Electric Utilities has a peak load of ~7,700 MW with 36.7 billion kWh delivery.

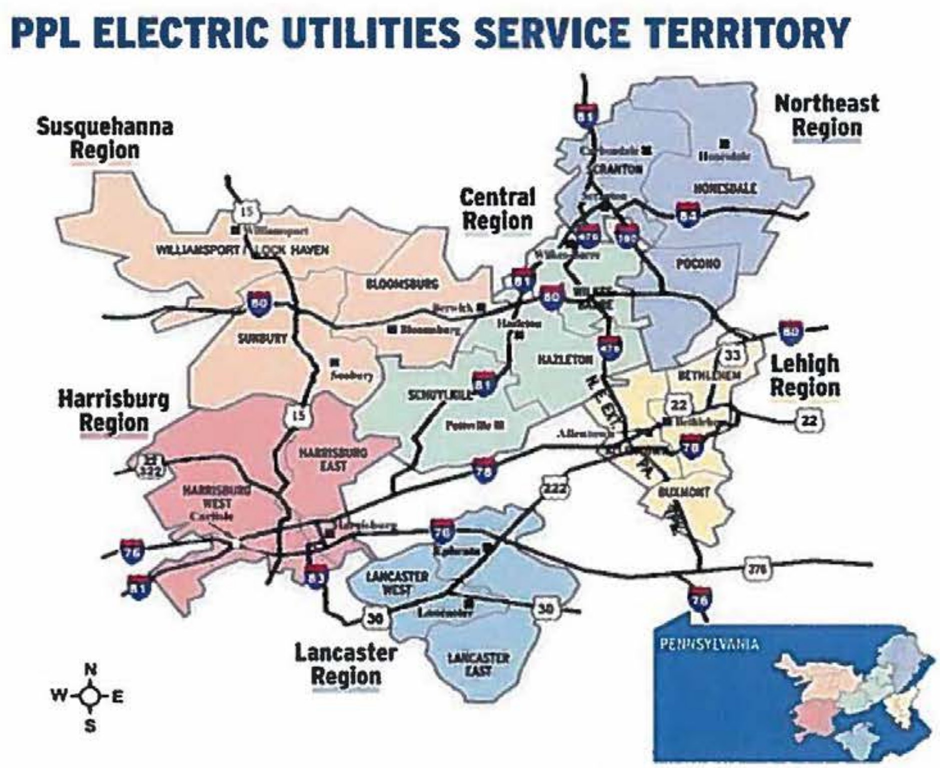


Figure 4-1
PPL Electric Utilities Service Territory

PPL Electric Utilities was one of the first utilities to introduce an automated meter-reading system, starting the program in November 1999 and completing the deployment to its 1.4 million customers in October 2004. Beginning in the spring of 2002 and concluding in the fall of 2004, PPL deployed an automated meter-reading system that included the replacement of over 1.4 million meters, installation of communications equipment in over 330 substations, and modified meter data and billing systems. Total implementation cost was $163 million. The automated meter-reading system replaced 175 manual meter readers and allowed the reduction of personnel for large power installations from 17 to 11.

With manual reads, PPL Electric Utilities experienced 95% accuracy (due to human error and weather, especially snow); accuracy with automated meter reading is now close to 99.8%.

PPL Electric Utilities started change management for business processes six months before installation. Before installation started, 200 business processes were reviewed; 70 risks were identified and addressed and appropriate changes made to ensure the successful transition to the automated meter-reading system. Many of these changes related to billing processes and impacted revenue assurance and, thus, non-technical losses.

The information technology staff was actively involved in the project team, contributing to the smooth transition. During the installation period, manual meter reads were sent to billing using middleware, so downstream processes did not notice the difference between manual and remote meter reads. The computer software programs and interfaces necessary to transfer the automated meter reads to the PPL billing system were developed in-house. Among these were the data validation and revenue assurance tools. Statistical analysis was used very early on. From the beginning of the project, the information technology staff, using its own software, provided effective and productive applications for revenue assurance.

Although the system deployed by PPL Electric Utilities was an automated meter-reading (AMR) system, it was designed as an advanced metering infrastructure (AMI) system upon which expanded capabilities could be deployed. These expanded capabilities include two-way communications and the use of a commercial MDM solution.

The AMI system reads meters three times per day; hourly data collected daily for each customer. The database currently (2008) holds over three terabytes (two years of data). This is the largest database of hourly data in the industry.

PPL Electric Utilities was one of the earliest utilities to deploy and utilize AMR/AMI throughout its entire service territory, establishing it as one of the leaders in the industry. As of 2006 it had the second largest deployment in the United States (1,353,024 meters), after PECO Energy (1,759,913); Wisconsin Energy was third (723,000), Wisconsin Public Service fourth (396,837), and United Illuminating fifth (324,992).

The transition from manual to remote meter reading at PPL Electric Utilities was well managed with an inclusive and highly competent project team, making it a model for the industry. Most importantly, with respect to the subject of this study, the AMR/AMI system at PPL Electric utilities provides new and innovative tools for revenue assurance that have a positive impact on the reduction on non-technical losses.

Revenue Assurance Using Meter Data from AMI with Meter Data Management Software

AMI fundamentally alters the way revenue assurance operations are performed. In the past, the Revenue Assurance group at PPL Electric Utilities used various strategies to identify specific target accounts for investigation. Most of these strategies involved manual analysis of large quantities of data, a labor-intensive exercise. The data available for such queries were generally limited to daily and monthly consumption. The results were based on an *ad hoc* process that takes considerable time, with different screening tests being designed and deployed at different times. AMI, with a robust MDM system, changes this paradigm in several ways.

The collection of higher-frequency data and meter status by AMI—reverse rotation flags, outage count indicators, interval data, and metered usage on previously cut meters—is just the beginning of the assurance solution. MDM software helps utilities analyze AMI data, providing knowledge about customer energy use. In-depth analysis helps pinpoint where and by whom power is being diverted, making it easier to identify cases of theft. For example, such analysis enables the utility to discover when there is energy use on non-paying accounts and when there is no use for specific time periods on an active account.

Data Repository

The core repository of data is collected from multiple sources: AMI meters, weather, customer and billing, SCADA, GIS mapping and real-time pricing, as shown in Figure 4-2. The data are validated and stored in two scenarios, working and approved.

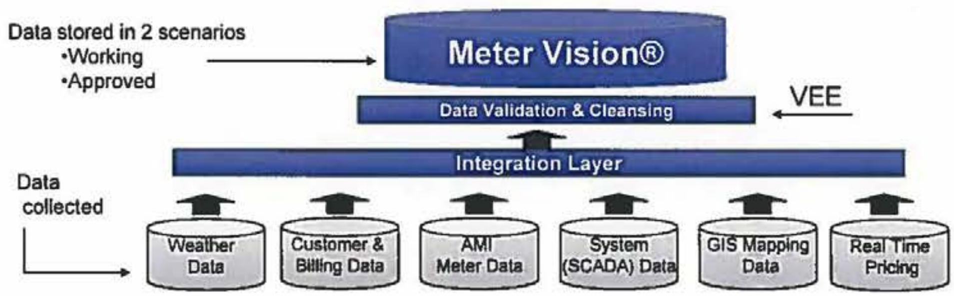


Figure 4-2
Data Repository

Data Repository and Applications

Revenue assurance software allows PPL Electric Utilities to zero in on problem accounts by combining data collected by the AMI system, such as daily readings, interval data, and momentary interruption notifications (blink counts) with other pertinent information such as daily temperatures, meter status, and account status.

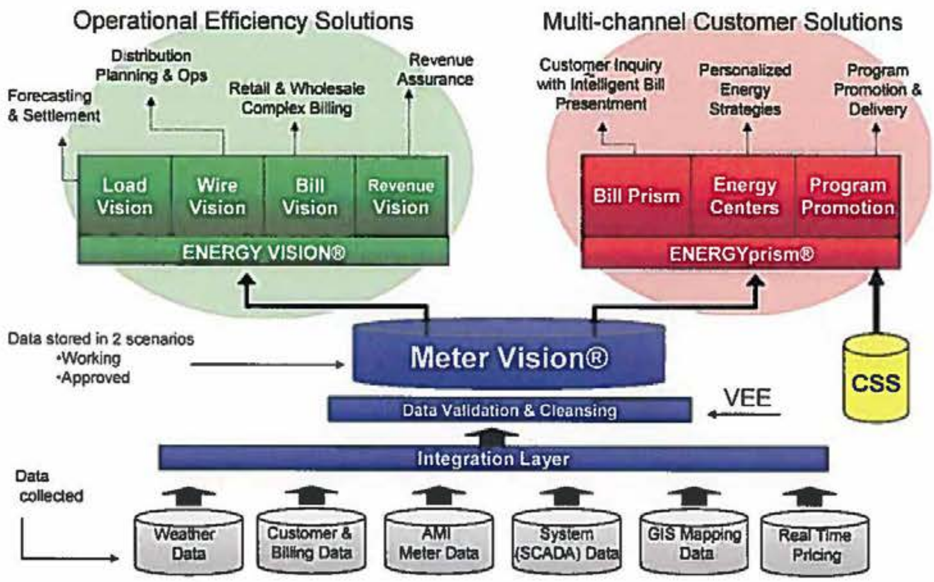


Figure 4-3
Data Repository and Applications

The combination of data and applications for analysis together constitute the Revenue Vision solution at PPL Electric Utilities (Figure 4-3).

Revenue Vision

The Revenue Assurance group at PPL Electric Utilities uses MDM software, called Revenue Vision, to help them simplify the process for identifying possible cases of theft, meter tampering, or equipment problems. This takes a significant amount of guesswork out of the effort to identify possible theft cases. Rather than make assumptions about the cause of a reduction in consumption, the granularity of data available from MDM can provide a pattern that can be used to identify theft or failing equipment with a high degree of confidence so that the site visit to confirm will be fruitful. It also allows users to create rules and logic, manage the list of outputs, tweak logic for better results, and group the results by geographic location to make it easier to assign work to field investigators. An optimum solution would automatically notify group members of anomalies around usage patterns.

PPL Electric Utilities uses a commercial MDM solution to improve analyses of large volumes of interval, daily, and meter data collected by its AMI system. By combining various meter, premise, and account data, the software makes it easier to identify problem meters. PPL Electric Utilities identifies suspicious consumption patterns by applying specific, utility-defined screening tests to a targeted population of accounts, meters, or other entities. The goal is to define tests narrowly enough so that the data combination yields a true and manageably sized "hot list" of accounts requiring investigation.

Revenue Assurance Application

- The revenue assurance application is used today to find meter issues as well as theft.
- The application collects raw data from meters with a specific scenario.
- For example, meters with 3 hours of no use are collected between the hours of 6 pm and 6 am and reports them to a "hot list" for further investigation.
- Additionally, it collects meters that have reverse rotation with blinks and puts them on a "hot list" for additional investigation.

Tests

The Revenue Assurance group began its project by evaluating existing tests already in use for assessing monthly meter readings. During the course of the review, they were able to determine the biggest revenue loss issues, such as equipment malfunctions, installation issues, and potential theft, and to identify usage patterns that were indicative of each problem, as well as the customer class or attribute that should be tested. Upon completion of this exercise, the group came up with eight logic tests to implement within the MDM application and then determined the criteria for each; for example, the meter type or the account type as well as selecting a schedule for running the test (weekly, monthly, or quarterly).

Design and implementation of screening tests within MDM are distinctly separate steps. Analyses are designed to fit customer load and data characteristics to effectively identify energy theft or tampering. Once an analysis is designed, it is implemented as a regular production process, making it possible to keep up with the examination of current data and alert the Revenue Assurance group of anomalies as soon as they arise.

The design step involves exploratory analysis of different test schemes by running, reviewing, and comparing different result sets. Hourly data are utilized for these tests and supplemented by external data sources such as weather data, GIS, and customer characteristic data. In the design phase, these tests are run on all or just a sample of customers, with the primary purpose of evaluating the effectiveness of the tests, rather than simply generating customer lists from the tests.

Tests

- Periodic zero use/with blink—shows meter blinks and zero usage
- Periodic zero use/no blink—same above with no blinks
- Reverse rotation/with blink—shows reverse meter rotation
- Reverse rotation/no blink—same as above with no blink

Note: Typically, abnormal blink counts and reverse rotations counts are due to meter tampering.

PPL continues to refine other tests that will allow them to monitor accounts within two days of an event (for example, termination for non-payment or slowing or stopped meter).

The implementation step is automated. Once logic tests are found to be effective by the analyst, they are put into production by scheduling them as automated runs for whatever period makes sense. All AMI data are initially screened by the validation rules inherent in the MDM system.

After validation, certain accounts are identified for further review. The revenue assurance analyses are run automatically on selected meters. Tests can be nested into a single logic string within a single production run, rather than performed sequentially in multiple runs.

Analysts apply standard tests or test combinations to specific accounts or groups of accounts. Failure of a combination of tests may detect meter tampering. For example, the combination of a loss of power indicator on a meter with a reverse rotation flag is a better indicator of theft than either test alone. No one test determines energy theft or meter tampering, but various combinations of failures may place an account or meter on the suspicious account list.

Workflows

The next step in implementing the logic tests required that a workflow be set up for each of the tests (Table 4-1). The workflows consist of a name, brief description, the group of entities to be included in the test, and the filters necessary to identify the attributes of the entities included. Once the workflows were completed, the group determined how often to run the test.

PPL Electric Utilities generally runs tests weekly, but has the flexibility to change the frequency of test runs. Weekly runs allow better management of output, and there is an added security benefit from a frequent "electronic eye" on every meter in the field.

Table 4-1
Revenue assurance workflows at PPL Electric Utilities

Revenue Assurance Workflows at PPL Electric Utilities	
Workflow	**Description**
800 Series Commercial	Captures commercial meters that have 20% or greater decrease in monthly consumption and/or peak demand in comparison with lowest monthly consumption and peak demand of previous 12 months
800 Series Residential	Captures residential meters that have 20% or greater decrease in monthly consumption in comparison with lowest monthly consumption of previous 12 months
Seasonal Use	Captures seasonal meters that have 20% or greater decrease in seasonal consumption and/or peak demand in comparison with seasonal consumption and peak demand 1 year and 2 years ago
Billing Constant	Captures meters for which billing constant changed from that of previous month
CIM Monthly Commercial	Captures commercial meters that have registered 1000 kWh of consumption since account became inactive
CIM Monthly Residential	Captures residential meters that have registered 1000 kWh of consumption since account became inactive
CIM Weekly Commercial	Captures commercial meters that register average daily consumption of 500 kWh or greater since account became inactive
Load Factor Commercial	Captures commercial meters that have monthly load factor of 1 or greater
Load Factor Residential	Captures residential meters that have monthly load factor of 1 or greater
Periodic Zero Use Commercial	Captures commercial meters that register four or more consecutive hours of true zero use during calendar month (excl. power outages)
Periodic Zero Use Residential	Captures residential meters that register more than 40 occurrences of consecutive 12 hours of zero use during calendar month (excl. power outages)
Reverse Rotation and Blink	Captures meters that register reverse rotation and blinks, indicating meters potentially tampered with
Reverse Rotation and No Blink	Captures meters that register reverse rotation but no blinks, indicating defective meters creeping backwards
Reverse Spike Commercial	Captures commercial meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Reverse Spike Residential	Captures residential meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Zero Use Commercial	Captures commercial meters that register zero consumption for calendar month
Zero Use Residential	Captures residential meters that register zero consumption for calendar month
Company Use	Captures meters classified as Company Use so they can be verified as such
Commercial Rate and Residential Revenue Class	Captures meters that have commercial rate class and residential revenue class
Residential Rate and Commercial Revenue Class	Captures meters that have residential rate class and commercial revenue class

Figure 4-4 shows a workflow that is used to find commercial meters that have 20% or greater decrease in the monthly consumption and or peak demand in comparison with the lowest monthly consumption and peak demand of the previous twelve months.

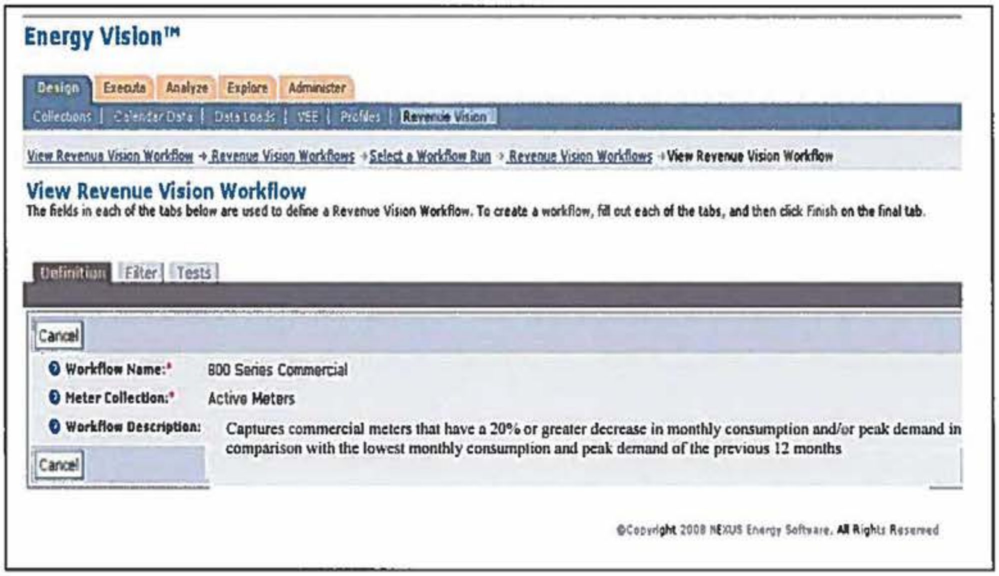


Figure 4-4
800 Series Commercial Workflow (Screen Print)

Filter

Within Revenue Vision (see Figure 4-5 Data Repository and Applications) a filter is applied by selecting the specific attributes, as well as a specific value such as commercial vs. residential—active vs. inactive—and so on.

Figure 4-5
Filter (Screen Print)

"Hot List"

The results are displayed on a "hot list" (Figure 4-6) from which a Revenue Assurance specialist can pinpoint candidates for further investigation and corroboration of the AMI indicators.

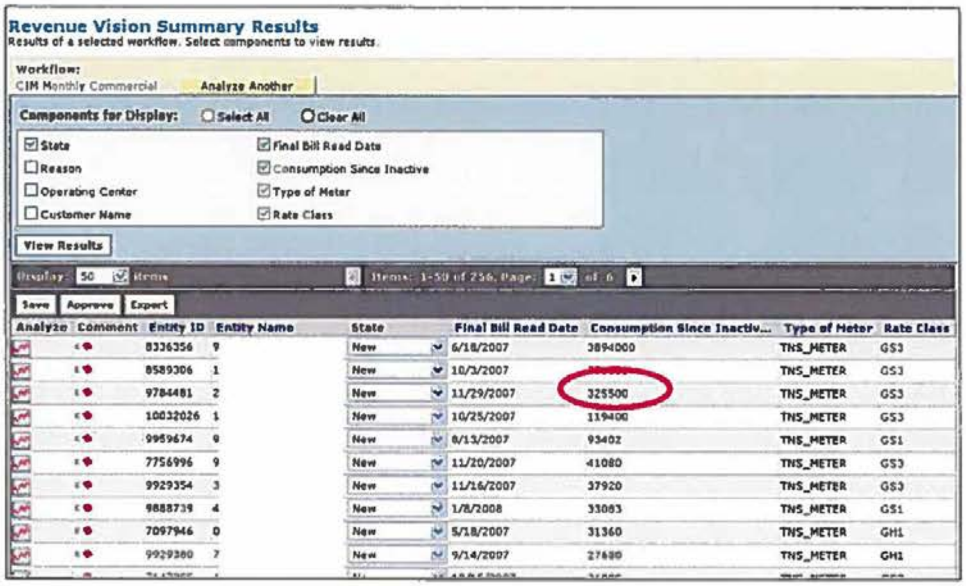


Figure 4-6
Hot list (Screen Print)

The "hot list" is used to prioritize revenue assurance leads for field personnel, thus reducing service order costs and efficiently identifying likely sources of non-technical losses.

Example of Theft Detection Using a Usage Pattern

In one recent case, PPL Electric Utilities was able to identify potential theft by looking at a usage pattern (Figure 4-7).

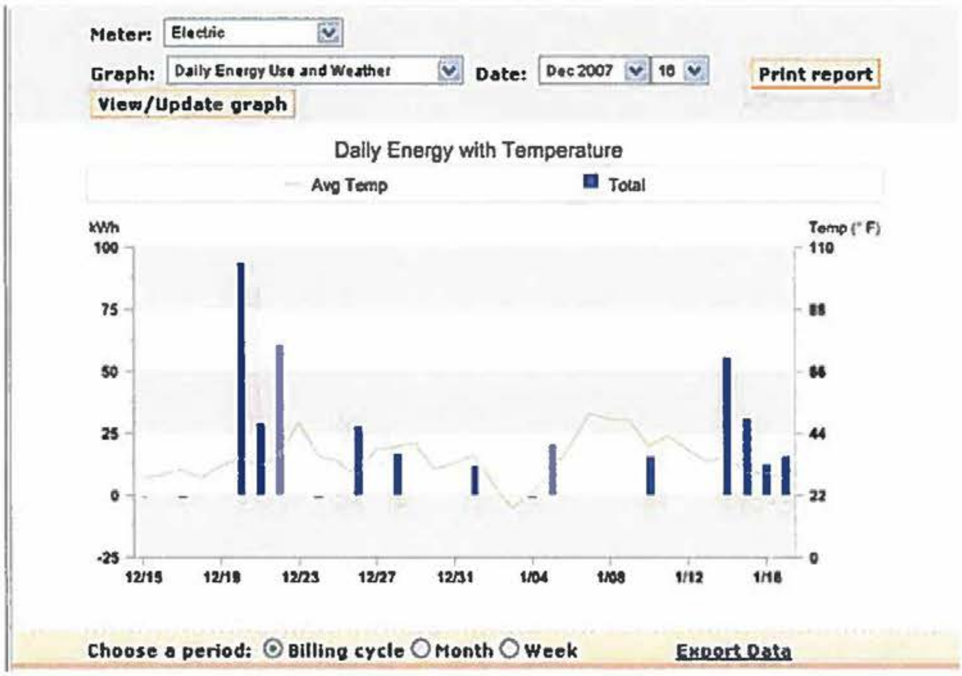


Figure 4-7
Usage pattern indicating abnormal meter behavior

The graph, taken from reports output from the MDM, indicates a suspicious usage pattern, with the meter going into a reverse rotation several times during a single billing cycle. What is more, there are days during the month when the customer is not using any power, while on other days the meter recorded usage. On December 20, 94 kW of usage was recorded, for example, while on January 3, when the temperature was -8°C, no usage was recorded. An investigation of the premises based on analysis of the AMI data indicated that the customer had tampered with the meter. Wires were attached to the meter's potential clip (Figure 4-8).

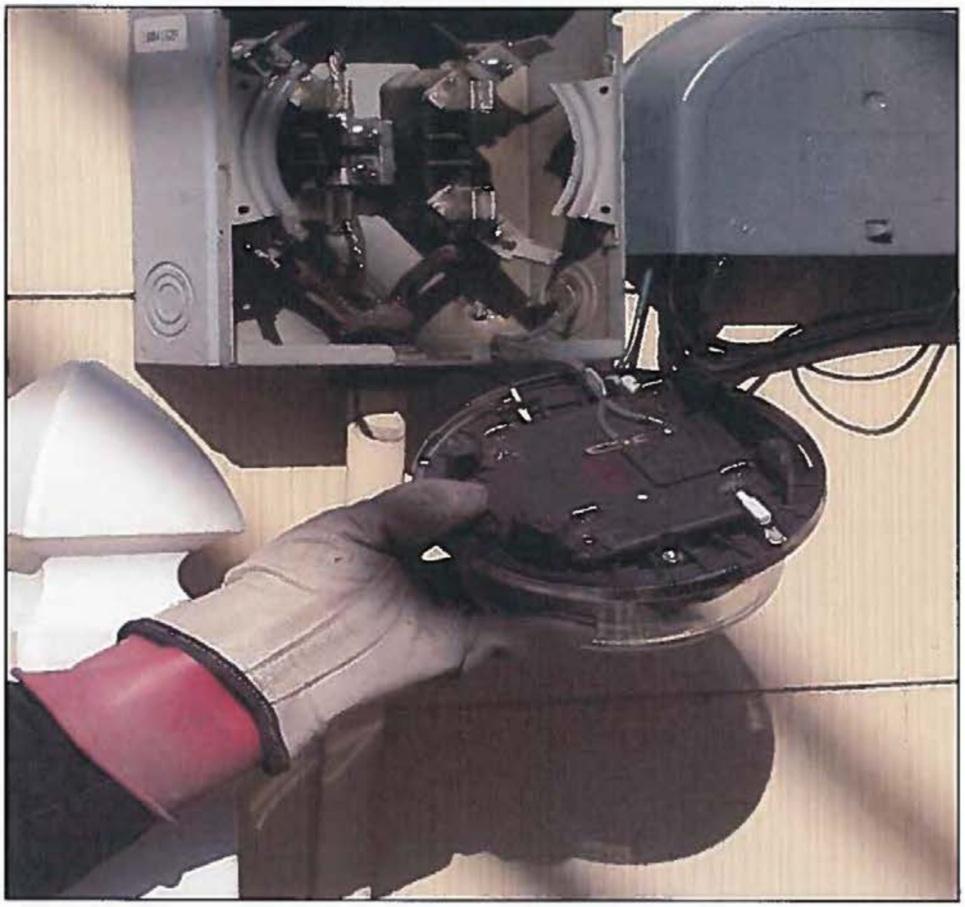


Figure 4-8
Meter recorded in Figure 7 with wires attached to its potential clip

The bypass was controlled by a simple toggle switch (Figure 4-9).

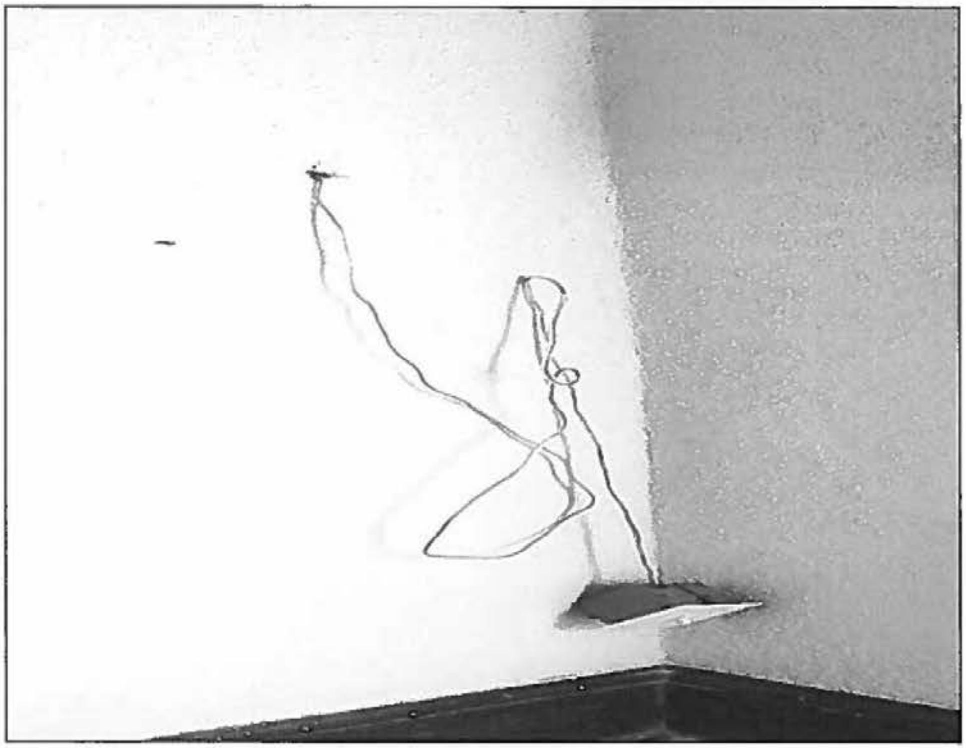


Figure 4-9
Toggle switch controlling the meter bypass

In this case, PPL Electric Utilities was able to use the interval data to extrapolate usage for rebilling purposes from the periods that were recorded.

Further, PPL Electric Utilities can use the detailed data for responding to questions raised by the judicial system.

Results

PPL Electric Utilities has had positive results from implementation of MDM-based revenue assurance software. The results for April and May 2008 are shown in the insert below.

RESULTS
April and May 2008

- Forty (40) cases were identified for a field investigation where 100% resulted in action being taken.
- Eighteen (18) of the cases were a result of equipment issues.
- In twenty (20) of the cases, theft was detected.
- Two of the cases revealed customer-owned generation via windmill and solar panel; these cases were identified through anomalies in blink counts and reverse rotation on the meters.

Reduction of Non-Technical Losses Using Meter Data Management

As defined in Chapter One, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These losses are associated with unidentified and uncollected revenue, arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of utilities, due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses. In this example, the focus has been primarily on issues related to theft. However, in the future, PPL Electric Utilities expects to further maximize the benefits that can be derived from its meter data, such as using the features of its MDM system in customer service to respond more quickly and accurately to high-bill inquiries.

AMI at PPL Electric Utilities is an evolving enterprise. The ongoing initiatives of the AMI operations team will lead to further reductions in non-technical losses, as well as further benefits in terms of operational efficiencies and customer service.

Sources

AMI and MDM Program—PPL Electric Utilities, Mike Godorov, Manager; AMI Operations, Kimberly Golden, Supervisor—Information Solutions; and Wayne Fairchild, Special Project Manager, AMI, interviews and presentation. September 18, 2008.

PPL Electric Utilities Reduces Revenue Losses with AMI, Bernie Molchany, Manager—Revenue Assurance, PPL Electric Utilities; Michele Pierzga, Lead Business Systems Analyst, PPL Services Corporation; and Jackie Lemmerhirt, Director of Product Management, MDM, Aclara, Metering International. Issue 3 2008.

Using Meter Data from AMI with Meter Data Management Software to Identify Theft and Equipment Issues, Michele A. Pierzga, Lead Business Systems Analyst, PPL Services Corporation, Autovation 2008, Atlanta, GA. September 7, 2008.

A
APPENDIX

Product Differentiators

- Each product has its own distinct functional strengths and weakness.
- Each product has its own unique architecture differentiators, such as the ability to perform and scale as needed.
- Each product is implemented with differing technologies that the utility IT department has to support and integrate with other applications in the enterprise.
- Some products have service-based architectures at the enterprise level; others do not.
- Some products have well-defined interfaces and points of interoperability; others do not.
- Some products meet industry and international standards; others do not.
- Some products adhere to Smart Grid principles;[84] others do not.
- In addition, each vendor is unique in its level of product development maturity and implementation experience and expertise.

Utilities are encouraged to find the solutions that best fit their needs—in the present and foreseeable future.

[84] As envisioned by Smart Grid researchers such as EPRI, the California Energy Commission's Public Interest Energy Research program, the Modern Grid Initiative, and DOE's GridWise program.

Vendor List

Aclara Software
- Energy Vision®
- http://www.aclaratech.com/software/

Advanced AMR Technologies, LLC
- 8800 Energy Information and Control System
- http://www.advancedamr.com/

American Innovations Ltd.
- AIMetering System®
- http://www.aimonitoring.com

BPL Global
- Power SG™ Theft Detection
- http://www.bplglobal.net/

Detectent, Inc.
- Revenue Enhancement Suite
- http://www.detectent.com/

E-Mon LLC
- E-Mon Energy™
- http://www.emon.com

Echelon Corporation
- Networked Energy Services
- http://www.echelon.com

Ecologic Analytics, LLC
- WACS Meter Data Management System
- http://www.ecologicanalytics.com/

EKA Systems, Inc
- Energy Insight
- http://www.ekasystems.com

Elster Electricity, LLC
- EnergyAxis® System
- http://www.elsterelectricity.com

eMeter Corporation
- eMeter's Consulting and Implementation Services
- http://www.emeter.com/

EnergyICT Inc.
- COMServerJ
- http://www.energyict.com

Enerwise Global Technologies, Inc
- Metering & Integration
- http://www.enerwise.com

Envision Utility Software Corporation
- foCIS™
- http://www.envworld.com

IBM Corporation
- Asset Monitoring and Advanced Metering
- http://www.ibm.com/us/

InStep Software, LLC
- Enterprise Energy Management Software
- http://www.instepsoftware.com

Itron
- Enterprise Edition Customer Care
- http://www.itron.com

MeterSmart
- Meter Data Management
- http://www.metersmart.com

Metretek Inc.
- DC2000
- http://www.metretekfl.com/

MU Net, Inc.
- WebGate® System
- http://www.munet.com

Neptune Technology Group Inc.
- FIELDNET®
- http://www.neptunetg.com

Oracle
- Oracle Utilities Meter Data Management
- http://www.oracle.com/industries/utilities

OZZ Corporation
- Meter Data Management Solutions
- http://www.ozzcorp.com

Powel, Inc.
- Meter Data Management
- http://www.powel.com/

Power Measurement
- EEM Systems
- http://www.pwrm.com/

SAP America, Inc.
- SAP Enterprise Data Management
- http://www.sap.com/usa/industries/utilities/index.epx

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California; Charlotte, North Carolina; and Knoxville, Tennessee, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

Together...Shaping the Future of Electricity

1016049

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

gridSmart Full Deployment
Total Cost December 2016
(post-allocated view)

Capital

Project		LTD Total
GSAMIFDEP PSO/GS Full Deploy AMI		77,326,950.53
GSCEDFDEP PSO GS Full Deploy Con Ed		1,663,198.88
GSITSFDEP PSO/GS Full Deploy IT		18,679,018.48
GSNETFDEP GridSmart Network		11,684,848.24
GSPMGFDEP PSO/GS Full Deploy Proj Mgt		1,457,452.59
		110,811,468.72

O&M

Project		LTD Total
GSAMIFDEP PSO/GS Full Deploy AMI		653,135.93
GSHANFDEP PSO GS Customer Programs		5,656,813.01
GSITSFDEP PSO/GS Full Deploy IT		3,393,006.74
GSNETFDEP GridSmart Network		445.42
GSPMGFDEP PSO/GS Full Deploy Proj Mgt		4,054,699.06
		13,758,100.16

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 19
To Appalachian Power Company

<u>Interrogatory Staff 19-452:</u>

Please refer to the Company's response to Staff Interrogatory No. 4-066 in Case No. PUR-2018-00198 (see Attachment C). What is the current cost per truck roll (if changed)? Please provide any workpapers or other data used to derive this amount (Microsoft Excel format with all formulas intact).

<u>Response Staff 19-452:</u>

This response contains confidential information and is provided pursuant to the Hearing Examiner's April 15, 2020 Protective Ruling.

See Staff 19-452 Confidential Attachment 1 for the costs of truck rolls in 2019 ($20.42) and the number of avoided truck rolls attributable to AMI (141,341), equating to approximately $2.9 M in savings in 2019.

The foregoing response is made by William K. Castle, Dir Regulatory Svcs, on behalf of Appalachian Power Company.

INDIANA MICHIGAN POWER COMPANY
CITY OF SOUTH BEND
DATA REQUEST SET NO. SB DR 4
IURC CAUSE NO. 45235

DATA REQUEST NO SB 4-06

REQUEST

Provide all cost benefit analyses performed by or on behalf of or reviewed by I&M to evaluate the effectiveness of installing AMI meters.

RESPONSE

A generic discussion draft analysis was prepared by an I&M operations employee using a generic AEP template and inputs. Neither the inputs nor the analysis were completed. The template was not focused on the transition from AMR to AMI via a planned deployment versus a reactive deployment, which is the technology issue here. As a result the draft analysis was not used by I&M management. See "SB 4-06 AMI Draft.pdf."

gridSMART

I&M AMI Full Deployment Benefits / Cost Analysis

May 2016

DRAFT

Summary – Major Assumptions

- Business Case reflects company spend and customer cost/benefit perspective
- Full Service Territory (IN & MI figures shared as well)
- 3 Year Deployment of Meters
- Net MRO FTE reduction of 3 FTEs (12 reduced / 9 new positions)
- 5 Year Ramp Up of Consumer Programs including Prepaid Metering, Direct Load Control (DLC), TOU and TOU w/ CPP, and energy usage through web portal
- Remote disconnect functionality included and fully operational
- Prepay is deployed

Summary – Full Deployment

- Full AMI deployment – install additional 608,000 meters over 3 years
  - $82 million capital investment (3 years)
  - $6.0 million O&M (3 years) – Security and ITRON Cost (License, SaaS, Maint)
  - $3 - $4M post-deployment O&M increase can be offset by labor reductions ($0.75 - $1.0M) and credit/collection savings ($4 - $5M)
  - ~$56M in stranded meter assets (AMR depreciated over 25 years)
    - 41,333,420 (Indiana)
    - 14,786,436 (Michigan)
  - Other non-financial benefits include customer experience benefits from AMI-enabled consumer programs, data analytics, and CO2 reduction
- Consumer Program assumptions
  - $2 million capital investment for Prepay / Consumer program IT enhancements (first 3 years)
  - $16.5 million O&M (first 5 years) and $1.8M ongoing (potentially recoverable through EE riders) – Not sure where the O&M is coming from. Assumption is I&M will continue to use current portal. Capital projects for TOU and other tariff offerings but should not have additional O&M tail. O&M Removed from totals but kept benefits
  - Spend more than offset by energy/demand reductions in long-term
- Customer rate impact TBD (will engage Regulatory when appropriate)

I&M gridSMART / Benefit Analysis (15 year view)

15 Year Benefits:	$78,600,150.66
15 Year Costs:	($110,519,812.57)
Benefit / Cost Ratio:	0.71
15 Year NPV Benefits:	40,745,740
15 Year NPV Costs:	(90,021,811)
NPV Benefit / Cost Ratio:	0.45

- Compares unfavorably to other internal and external business cases given full deployment of AMR

Combined benefit / cost ratio of 0.71. Regulatory business case would be built around customer experience including enablement of programs / technologies and application of analytics

Other Options to Consider

- Broader gridSMART deployment including Volt Var Optimization (VVO) and DACR (Distribution Automation – Circuit Reconfiguration) to strengthen overall business case
  - VVO – Energy, peak load reduction savings
  - DACR – SAIDI / Customer Outages Avoided savings

- Phased AMI deployment (e.g., urban settings first like AEP-OH)

- Targeted AMI deployment (e.g., Micro AP for credit/collections benefits)

Appendix

Financial Benefits - AMI

- "Hard" Field loaded labor net reductions – $0.8M annually
  - Meter Reading - $0.6M annually
  - Limited savings by full deployment of
- "Medium" Credit / Collections / Revenue Enhancements - $4-5M annually
  - *Assumes remote disconnect*
  - Reduced delinquency / bad debt
  - Reduction in theft
  - Lower consumption on inactive meters
  - Benchmarked to ensure in reasonable range of peer business cases

Financial Benefits - AMI

- Other "soft" O&M / Capital benefits – $500K annually
  - Billing/call center inflow reduction – $100K annually
  - Obsolete meter avoidance - $1.8M over 3-year installation
  - Capacity planning efficiency - $200K annually
- Peak load reduction savings (Programs) - $5-7M annually
- Energy reduction savings (Prepay) - $3-4M annually – Removed
- Reduction bad debt (Prepay) - $81K annually

Non-Financial Benefits – AMI

- Enables implementation of consumer programs (e.g., Direct Load Control, TOU) and new technologies (e.g., Powerley)
    - Significant energy / peak load reduction serves to offset the customer costs of AMI investment
- Enables prepaid metering that has proven customer satisfaction benefits (e.g., Salt River Project, Oklahoma Electric Cooperative and Arizona Public Service)
- Creates opportunity for increased customer flexibility / satisfaction through billing accuracy / better usage data (MDM, web portal)

Non-Financial Benefits – AMI

- Provides platform for proactive data analysis
  - Quicker identification of reliability / power quality issues
  - Decrease outage restoration times (CAIDI)
  - "Pinging" meters to confirm outages can reduce truck rolls and decrease CAIDI
  - Automation of outage orders (work in progress) could further reduce CAIDI
  - Load data ensures more precise capacity planning
  - Timely and accurate identification of theft / consumption on inactive meters
  - Improved mapping of transformer ties – improved outage prediction and quality of mobile alerts
  - Supports fuller view of 360 view of the customer
- Reduction of CO_2 from energy reduction (Prepay) and truck roll avoidance (will be quantified if we move forward)

I&M gridSMART Fundamental Assumptions

- Model includes components for AMI and Consumer Programs
  - Cost / benefit analyses were done on stand-alone basis
  - Program management expenses were included in AMI analysis
- 15-year project life
- AMI capital depreciated over 15 years; IT capital depreciated over 30 years
- Weighted Average Cost of Capital – 7.02%
- Customer growth rate – 0.5%
- PJM Energy and estimated Capacity pricing from CP&B
- AMI Deployment
  - 613,607 total meters – 585,929 single phase, 26,678 poly-phase, 1000 MicroAP
  - Financial benefits driven largely by credit / collections benefit requiring approval of remote disconnect; labor savings relatively small given AMR technology deployment
  - Average Meter Cost – $91 per meter – single phase, $188 per meter – poly-phase
  - Blended installation cost of network and meter at $20 device
  - Replacement Rate for Meter-Related Capital – 1% Years 1 – 20

I&M gridSMART Fundamental Assumptions (continued)

- Consumer Programs
  - Costs based largely on PSO experience (e.g., Prepay)
  - Prepaid Metering assumes 8% penetration rate, 10% energy reduction
  - Other programs ramp up to max participation over 5 years (Years 2 through 6)
  - No assumed participation in Year 1
  - Participation/penetration rates:
    - Direct Load Control – 7%
    - TOU – 5%
    - TOU w/ CPP – 0.6%
    - Web Portal – 5%
  - Peak load reduction %s:
    - Direct Load Control – 35%
    - TOU – 10%
    - TOU w/ CPP – 10%
    - Web Portal – 1%

VERIFICATION

The undersigned, Stephen D. Blankenship, being duly sworn, deposes and says he is a Region Support Manager for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Stephen D. Blankenship

COMMONWEALTH OF KENTUCKY)
) Case No. 2020-00174
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen D. Blankenship, this 10th day of September 2020.

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and states he is the Director of Regulatory Services for Kentucky Power Company that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Brian K. West

State of Indiana)
) ss Case No. 2020-00174
County of Allen)

Subscribed and sworn to before me, a Notary Public, in and for said County and State, Brian K. West this 9th day of September, 2020.

Regiana M. Sistevaris

Digitally signed by Regiana M. Sistevaris
Date: 2020.09.09 07:47:49 -04'00'

Regiana M. Sistevaris, Notary Public

My Commission Expires: January 7, 2023

My Commission Expires: ______________________