

**UNIFORM BUSINESS PRACTICES
FOR
UNBUNDLED ELECTRICITY METERING
VOLUME TWO**



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UBP Sponsoring Organizations

The Edison Electric Institute (EEI)
Coalition for Uniform Business Rules (CUBR)
National Energy Marketers Association (NEM)
The Electric Power Supply Association (EPSA)

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Introduction

National uniform business practices (UBP) allow stakeholders responsible for implementing unbundled electricity metering services to realize reduced system development costs, less duplication of effort between states, and improved transactional efficiencies.

Objective

The overall objective of the UBP unbundled electricity metering subgroup is to produce a set of uniform business practices for unbundled metering within the retail electricity market. The process of developing a set of uniform practices is neither an endorsement nor a rejection of the policy choice to implement unbundled electricity metering. Rather, these practices have been developed to facilitate the business processes when, and if, this policy direction is taken by a state. These uniform practices are intended to allow consistent implementation on a state-by-state basis and as such will facilitate the development of consistent market rules. Such consistency allows the stakeholders responsible for implementing unbundled electricity metering services to realize reduced system development costs, less duplication of effort between states, and improved transactional efficiencies

Development Process

In March 2000, under the sponsorship of the Uniform Business Practices group (UBP), a group of utilities, energy suppliers, regulators, vendors, metering suppliers, and other interested parties was formed to participate in workshops which would address the complex issues associated with the unbundling of electricity metering services. While the UBP sponsored UBP Metering effort is a unique collaborative approach to identify uniform business practices for the unbundled electricity metering market, it is by no means the first such effort. Previous efforts include:

- The Coalition for Uniform Business Rules (CUBR) document outlining detailed procedures for unbundled electricity metering (September, 1999);
- Utility Industry Group (UIG) work on Electronic Data Interchange (EDI) standards that could be used to support unbundled electricity metering;
- Existing and proposed business rules of various states, including Arizona, California, Illinois, Nevada, New York, and Pennsylvania

These documents, standards and rules were used as references by three working groups that were formed to produce a draft report by July 2000. The groups met several times, conducted numerous conference calls and exchanged email comments and documents to resolve issues.

Throughout the meetings and conference calls the following set of norms were followed:

- Focus on best practices, not policy;
- Focus on requirements and responsibility for performing functions;
- Ensure practices are technically feasible;
- Make practices detailed enough to be workable and flexible enough for individual states to build upon;
- Minimize impacts on current infrastructure;
- Focus on retail market processes, such as retail customer metering, as opposed to wholesale market functions, such as wholesale or exchange metering;
- Seek to include all market participants;
- Support the process with an Internet web site and list server, to enable participation by stakeholders unable to attend the workshops;
- Depend on participating stakeholders to "nominate" practices and language for group consideration;
- Consider that speed to market requires compromise between the "right" scope and the "right" level of detail;
- Encourage strong, non-adversarial working relationships between participants.

Applicability, Scope and Functional Areas

1. The unbundled electricity metering UBP are applicable to the retail access markets where states have decided to unbundle electricity metering services as part of a Retail Access program. This document is not intended to apply when metering services are not open to competition by act of the legislature, policy board, or the Applicable Regulatory Authority (ARA)¹.
2. The practices address physical hardware of the meters and related equipment as well as meter reading, data management and data exchange methods. Although not physically divided, the document is organized into the following topical areas:
 - General Overview – This section contains general information on possible market structures and participants, customer and stakeholder rights/ responsibilities, qualification and requirements, and auditing and reporting.
 - Meter Hardware, Installation and Maintenance – This section contains specific information regarding the physical nature of metering.

¹ See Glossary for definition of Applicable Regulatory Authority

- Meter Reading and Meter Data Collection – This section contains specific information on business practices related to the collection and processing of metered usage data.
3. Three functional metering service areas are identified and addressed in the document.
- Meter Service – includes physical services and hardware located at customers' site(s) (meter installation, maintenance, and testing). These functions are the responsibility of the Meter Service Provider (MSP).
 - Meter Reading Service – includes meter reading (cumulative reads, interval reads, direct reading, remote reading) and reporting. These functions are the responsibility of the Meter Reading Service Provider (MRSP).
 - Meter Data Service – includes data management and exchange functions (data maintenance, data validation, data estimation). These functions are the responsibility of the Meter Data Service Provider (MDSP).

Organizationally, these services may be provided by a single business entity or by multiple business entities.

Meter Service Agreement

A Meter Services Agreement should be executed between the parties to detail the rights, responsibilities, and liabilities of each party, to the extent not specifically covered by other governing documents.

Preface

Introduction

This document presents a set of recommended business principles and practices to guide the interaction of various market participants where unbundled electricity metering service is implemented. These recommended practices have been developed by a diverse group of parties, some with extensive experience in the implementation of unbundled electricity metering. These practices represent efforts by the participants to balance the interests of Customers, Suppliers, Metering Service Providers and Utilities and cover a wide range of issues and processes necessary to enable unbundled electricity metering. There is a great deal of interaction amongst the practices described herein; therefore, adoption of individual practices may be inefficient or impractical without the adoption of other recommended practices. Therefore, this document should be considered in its entirety.

Legal Precedence

The practices and rules provided in this document are not intended to supersede existing laws, regulations, or regulatory requirements and, to the extent that these practices and rules may be inconsistent with those existing requirements, the laws, regulations, and regulatory requirements shall continue to apply in all cases.

Existing Practices

While the goal is to have uniform business practices used as widely as practicable, participants do not expect this document to be cause for immediate replacement of recently developed state-level practices, but instead, to serve as guidelines when those practices are reviewed in the course of time. Changes to existing practices should only be made after careful consideration of costs and benefits for all stakeholders, as well as applicable legislative policy.

Implementation of the Practices

It is appropriate to include these recommended practices in the applicable governing documents. In that regard, it is recommended that tariff language, if appropriate, be of a summary or broad nature, leaving vehicles such as metering service procedures manuals to handle the details. This will provide the parties with more freedom to make timely changes as technologies improve, customer needs and concerns become known and markets develop during the period of transition that all will experience in varying ways, subject to the condition that any changes are consistent with orders and rules of the ARA. The parties who developed these recommended practices recognize that unbundled electricity metering services may result in incremental costs with its implementation.

Cost Recovery²

The parties believe that in order for these recommended practices to be implemented, recovery of the associated costs should be considered as with any other system or process imposed by regulatory authority or local governing body, in accordance with applicable legislation, settlements or local regulatory decisions. Also, for regulated entities that have already implemented unbundled electricity metering service, adoption of these practices may entail incurring costs to modify systems and processes. The parties that advocate the implementation of these practices acknowledge that the prudently incurred, net incremental costs of those changes should be given full consideration for recovery by the method deemed appropriate by the regulatory authority or local governing body in that jurisdiction.

Cost Effectiveness

Many of the issues associated with adoption of recommended business practices are dependent on the resolution of matters of broad public policy. It is anticipated that these policy issues will be resolved at the state level based on the needs and objectives of each jurisdiction. Practices should be evaluated by the ARA in light of local circumstances – including the pace of rollout of unbundled electricity metering services customers, the size of the market participants, and consideration of alternative approaches – to adopt a cost-effective approach to their implementation.

Use of Electronic Transactions

The exchange of metered data in a uniform electronic format is generally desirable and has been recommended in several sections of this report. However, in some instances the expected volume of transactions may not be high enough to warrant the infrastructure investments necessary to facilitate the exchange of data in a uniform electronic form. The development of the actual details of these uniform transactions is beyond the scope of this report. However, the intent was to strive for a single or limited number of, cross-jurisdictional, electronic transaction set(s) based on the best identifiable technology and practices. The development of these electronic data transaction sets must consider the market participants' resident technology and hardware along with the extent to which these existing systems can or should be leveraged.

Regulatory Policy Issues

There are a number of regulatory policy issues that affect the business practices addressed in this document. The key policy issues impacting unbundled electricity metering practices are identified below, along with implementation issues that were not resolved by the participants. Regulators are encouraged to consider these issues before, or in conjunction with, considering the recommended business practices.

² Certain consumer groups participating in this process do not believe that cost recovery should be a subject of this document.

Given the particular market structure chosen, the metering tasks should be subdivided into unique sub-tasks, such as: Meter Service, Meter Reading Service and Meter Data Service) defined above. Additionally, the definition of the interrelationships among these entities is critical in determining the relationships for the end-use customer. Additionally, jurisdictions differ in the level of participation of the utility in the competitive, or unbundled market. No effort was made in this document to select one market structure over another. In selecting a model, some issues to consider are:

1. Metering infrastructure control.
2. Possible conflicts of interest.
3. Customer metering service preferences.
4. Market structure viability.
5. Level of meter service unbundling.
6. Cost and time frame needed to implement metering provisions.
7. Needed changes to computer systems.
8. Shifting of financial risk – depending on which metering provisions are offered and how those options are implemented.
9. Enhanced Metering – potential benefits consumers might realize through enhanced metering services options.
10. Licensing unbundled electricity metering service providers – certification criteria and licensing process.
11. License Revocation – infractions leading to MSP license revocation and the imposition of penalties for remediation, restoration, or repair of metering problems.
12. Default Metering Service – provider, purpose, form, and pricing of default meter service. Providers of a default service in an unbundled electricity metering services environment incur many risks. Regulatory authorities may choose to recognize these risks in a variety of ways, including reflecting them in the price of service and addressing them in the terms and conditions of the service.
13. Line of Demarcation – physical metering system at a customer’s site may contain the following components; the meter, the meter pan/socket,

instrument transformers (i.e.: VT's and CT's), internal wiring, and communication links. Each jurisdiction will be required to define a line of demarcation between the distribution company and the meter service provider. In general, the ownership of the instrument transformers will have to be determined.

14. Service Delivery Points – definition, monitoring and control of service delivery points. A service delivery point is a point on the utility distribution system where the utility system connects to the end-user's system. Each jurisdiction will need to decide on which side of the utility/customer interface the metering installation will reside and the rights of various parties with respect to access to the service delivery point and/or the measurement data. Service delivery points are required to have meters, or must meet the requirements of unmetered service as defined by the applicable tariff. The monitoring and control of the service delivery points will be necessary to maintain the integrity of the end-use customer's billing determinants. Each jurisdiction must, however, address the selection of an appropriate entity for monitoring and control function.
15. Decision regarding and timing for competitive metering services .

Consumer Protections

The parties proposing these recommended business practices recognize that certain consumer protections are desirable to ensure that residential and small commercial consumers may benefit by the introduction of unbundled electricity metering services. These recommended business practices were developed with the expectation that implementation of unbundled electricity metering options would be accompanied by consumer protections and by effective educational programs designed to inform consumers about them.

While many of the recommended business practices in both volumes of this document embody specific consumer protections, e.g., use of Customer information, notification of enrollment, and anti-slamming protections, it is nonetheless helpful to emphasize several general principles relating to consumer protection that should guide the implementation and interpretation of these business practices. The following list is intended to summarize the key residential and small commercial energy consumer protection policy decisions that are typically addressed by policymakers and regulators prior to the adoption of Uniform Business Rules:

1. A simple enrollment and switching process that allows customers to select metering service providers efficiently and in a manner that prevents "slamming."

2. A Default Metering Service³ that is available at reasonable rates and upon reasonable terms and conditions.
3. A requirement that metering service providers be licensed to do business within the state to assure technical and financial fitness commensurate with the scope of retail activity intended by the provider.
4. Disclosure requirements relating to terms of metering service and billing content that will assist customers in understanding and comparing prices and other terms of metering service.
5. Policies and/or programs that recognize the needs of low-income customers.
6. Protections from unfair, deceptive, fraudulent, and anti-competitive practices, including, but not limited to, activities such as slamming (unauthorized switching), cramming (unauthorized charges), unlawful discrimination, failure to respond in a reasonable time to Customer complaints, and dissemination of deceptive information regarding pricing and terms and conditions of services.
7. Protection of the privacy of Customer information, including practices to prevent the unauthorized release or use of Customer information.
8. Access to an administrative process, approved by the ARA or local governing body, that provides a simple, quick, effective, and impartial means of resolving disputes about service and bills should the Customer be unable to resolve these disputes directly with the Utility or Metering Service Provider.
9. Investigations of potential violations by an authority with both the ability to impose penalties appropriate to the severity of any confirmed violation and sufficient resources to oversee the requirements for providing unbundled electric meter service.
10. A Consumer Education program that helps consumers make informed decisions, by understanding the new market structure, the benefits of unbundled electricity metering service, their rights and responsibilities, and educates consumers on how to avail themselves of unbundled electricity metering services.
11. Elimination of barriers to meter aggregation of residential and small commercial customers.

³See glossary for definition of Default Metering Service. Laws and regulations govern whether this service is available long-term as an alternative to competitive service or only during a transition period, after which Customers are expected to select a Supplier.

General Overview

Introduction

In developing a framework for the business rules applicable to unbundled electricity metering practices, the responsibilities of market participants were identified and the specific functions they were expected to perform were enumerated. However, the reader should understand that this document does not attempt to prescribe a particular market structure for unbundled electricity metering or how or what the inter-relationships between these market participants should be. It will be necessary for those implementing these practices and procedures to fully understand how such inter-relationships could potentially impact the provision of third party metering services. Notwithstanding the particular market structure that may be adopted by the ARA, the market structure that is eventually implemented should strive to promote the benefits of customer choice, maintain the integrity of metering and billing processes and minimize the potential for conflicts of interest to arise.

Summary of Conclusions Regarding Market Structure and Participants

1. Unbundled electric meter services consist of:
 - a. Meter Services, including installation, maintenance, programming, testing, and removal of meters and related equipment,
 - b. Meter Reading Services, including meter reading, and
 - c. Meter Data Services, including meter data translation, associating meter data with a customer, and the validation, editing, and estimating of meter usage data.

2. The number of market participants may vary from state-to-state depending on the rules issued in each jurisdiction. The market participants may include entities providing one or more of the following:
 - a. Energy Services
 - b. Meter Services
 - c. Meter Reading Services
 - d. Meter Data Services
 - e. Electric Distribution

3. Depending on the meter unbundling rules approved by ARA in a particular jurisdiction:
 - a. A retail customer may or may not be required to choose an energy service provider in order to pursue any unbundled electricity metering, meter reading, or meter data services.
 - b. A retail customer may or may not have direct or indirect business relationships with one or more entities providing unbundled electric meter services.
 - c. The default provider of electric meter services may or may not be required to provide individual unbundled electric meter services.

- d. The demarcation point between the distribution system and the metering system must be defined.
4. Service delivery points must be monitored and controlled.
5. Responsibility for meter removals associated with disconnecting service for non-payment should be defined in the unbundled electricity metering rules approved by the ARA.
6. Following implementation of unbundled electric meter services, all entity(s) providing such services should comply with the rules established by the ARA.

Summary of Conclusions on Unbundled Meter Services Provider Requirements

The following are guidelines that the supplier of metering services should adhere to when the supplier has a direct relationship with the customer:

1. Provide retail customers with a "Terms of Service" brochure or, in some way, document a complete disclosure of service terms and conditions in compliance with rules to be established by the ARA.
2. Based upon the methods approved by the ARA, customer authorization should be obtained in order to change service providers.
3. Provide the company's mailing address and toll-free telephone number for billing, safety, complaint resolution and other service inquiries.
4. Provide trained and knowledgeable persons to address customer safety questions and concerns, and other service inquiries.
5. Agree not to publicly disclose or make available for sale any customer meter usage or attribute data obtained from the meter, the customer or from the Utility.
2. Be responsible for meeting all safety and reliability standards and working with other companies with whom direct or indirect interconnections are maintained in order to ensure safe and reliable electric service to customers.
3. Make reasonable efforts to alert the customer to work being done associated with the meter that may require an outage, such as a meter change or a meter removal for testing.
4. Perform work on customer's premises in a safe and non-intrusive manner.

5. Make reasonable efforts to reestablish safe and reliable service within the shortest possible time, and work cooperatively with other companies to ensure timely restoration of services to customers.

Summary of Conclusions on Customer Rights & Responsibilities

1. The ARA should determine which customers are eligible for unbundled electricity metering services.
2. Eligible customers should obtain unbundled electric meter services from any entity that has been certified or licensed by the ARA to provide such services, in accordance with the market structure of that jurisdiction.
3. Meter ownership by end-use customers should be determined by the ARA in each jurisdiction.
4. If a customer owns the meter, that customer cannot independently act as their own unbundled electric meter services provider and cannot remove or otherwise control that meter
5. Entities other than the Utility, ESP or MDSP that have a direct business relationship with a retail customer, or their agents must have approval from the customer in order to gain access to existing meter usage data.

Summary of Conclusions on Energy Supplier/MSP/MDSP/ MRSP Rights & Responsibilities

1. The ARA should prescribe certification or licensing requirements for any entity, other than the Utility, that will be providing meter services directly to a retail customer. Each certified or licensed supplier must fully comply with any metering standards that have been adopted by that jurisdiction as a condition of maintaining certification or their license. These standards may include executing agreements with the applicable Utility.
2. Any entity providing meter services shall be responsible for the provision of all required services, but can elect to subcontract services to eligible third parties.
3. The entity providing meter services will fully cooperate in investigations of any customer complaints.
4. Any entity responsible for providing meter services shall maintain customer accounts and records as required by the ARA.

5. Any entity responsible for collecting and/or providing meter usage data must read, and/or validate, edit, estimate, and provide the data in a timely fashion to meet market requirements for billing and settlement.
6. Any entity providing metering services must notify the appropriate parties, if a safety-related or hazardous condition exists or evidence of tampering or energy diversion is found.
7. Any entity providing meter services shall require any person or agent with whom they sub-contract to adhere to the terms of all applicable rules and regulations.
8. Any entity providing metering services shall remain responsible for the actions of its agents or any other parties with whom it sub-contracts.
9. The MDSP must provide existing meter usage data to the Utility and the Energy Supplier but may not provide meter usage data to any other third party unless specifically authorized by the customer.
10. As approved by the ARA, an entity providing metering services has the right to disconnect a customer's service.
11. Any entity providing metering services has the right to disconnect service or remove a meter if the site is found to present an immediate safety hazard.
12. When a customer agrees to change from the Utility to another metering service provider, the Utility should provide all necessary data, in a timely manner, to the entity responsible for the unbundled electricity metering services. However, when a customer changes from one non-utility metering services provider to another provider, only limited data may be provided by the Utility (i.e. the Utility may not be responsible for maintaining all metering records when the Utility is not the meter provider).
13. The Energy Supplier has the right to initiate a process to discontinue operations of an unbundled electric meter services provider if that provider is not in compliance with the metering practices and procedures in effect in that jurisdiction.

Summary of Conclusions on Utility Rights & Responsibilities

1. The Utility has the right to inspect or audit the meter and meter installations of any entity providing metering service within their service territory.

2. The Utility has the right to access metering equipment at the customer's premise during normal business hours for the purpose of maintaining the distribution system. In an emergency situation, the Utility has the right to access the metering equipment at any time.
3. The Utility has the right to receive copies of all reports of tests performed on meters or transformers used in the determination of its revenue or of irregular conditions as found at the metering sites, such as evidence of theft-of-service.
4. The Utility has the right to terminate a customer's service or remove a meter for non-payment of Utility fees or charges.
5. The Utility has the right to disconnect service or remove a meter if the site is found to present an immediate safety hazard.
6. The Utility will fully cooperate with investigations of any customer complaint.
7. When a customer agrees to change from the Utility to another metering service provider, the Utility should provide all necessary data, in a timely manner, to the entity responsible for the unbundled electricity metering services. However, when a customer changes from one non-utility metering services provider to another provider, only limited data may be provided by the Utility (i.e. the Utility may not be responsible for maintaining all metering records when the Utility is not the meter provider.
8. The Utility has the right to initiate a process to discontinue operations of an unbundled electric meter services provider if that provider is not in compliance with the metering practices and procedures in effect in that jurisdiction.

Summary of Conclusions on Applicable Regulatory Authority Responsibilities

1. The ARA should determine the eligibility of an entity providing unbundled electric meter services.
2. The ARA should establish minimum procedures and performance standards for providers of meter-related services, as recommended in this document and has the final authority in determining whether a provider has committed an infraction that would merit loss of certification.

3. Notwithstanding other Legal remedies, the ARA is the final arbiter of all complaints involving an unbundled electric meter services supplier unless the parties previously agree to using third party arbitration in lieu of the ARA or to abide by the uniform business rules on dispute resolution chapter of this Report.
4. The approval process for specific metering devices should be determined by the ARA, as recommended in this document.
5. The ARA should specify the content of all required reporting by any market participant and ensure compliance with the prescribed reporting requirements.
6. The ARA has the authority to monitor all provisions of unbundled electric meter services and may delegate the actual monitoring tasks to an appropriate third party. (e.g., performance, site inspections, inspections of meter testing and repair facilities, audits, etc)

Licensing and Qualifications of Service Providers

Filing Requirements

All suppliers of unbundled electric meter services, excluding the incumbent Utility providing metering services under a tariffed rate, must file for and be licensed through a written application with the ARA. The requirement for a license is separate and apart from the requirement for the service provider to execute a Meter Service Agreement with the Utility.

The following information should be supplied by providers of unbundled electric meter services upon filing application with the ARA. Additional information may be required.

- a. Experience as a metering services provider
- b. Documentation of worker qualifications
- c. Documentation of worker training programs
- d. Documentation of facilities, systems, and operating procedures⁴
- e. Systems in place to handle 4 hour and 24 hour disasters and detect and prevent data tampering and theft.
- f. Data exchange test documentation⁵
- g. Agreement to provide access to audits
- h. Agreement to participate in complaint resolution procedures.

Revocation of License

License to provide metering related services may be revoked for.

1. Failure to follow Federal or State rules or codes including but not limited to ANSI, OSHA, NEC, NESC and consumer protection laws.
2. Failure to continue to meet the ARA eligibility or performance requirements.
3. Other areas of non-compliance with established practices and procedures as described in the subsequent sections of this document.

Financial/Insurance Requirements

1. All providers of unbundled electricity metering services should be required to provide financial security. The level of financial security should be proportional to the potential impact on the infrastructure which includes, but is not limited to, the following:
 - Damage to the transmission, distribution and/or customer systems resulting from incorrect installation, removal, or maintenance of meters.

⁴ Confidentiality of applicant's sensitive business or proprietary information must be maintained.

⁵ Information not due at filing but must be provided prior to providing service.

- Costs realized where the metering supplier exits the market without resolving metering performance issues.
 - Lost revenue from defective meters or poor performance by the provider of metering services.
2. The ARA should set an appropriate level of general liability insurance, performance bond or fidelity bond coverage to be maintained by each provider of unbundled electricity metering services.

MSP Qualifications

Introduction

In the course of performing on-site work on metering equipment, an MSP must utilize workers that are technically competent to handle the voltage and current levels provided by the distribution system as well as to properly install, remove, or test the related meter. The MSP is responsible for ensuring that these employees are trained and qualified to perform the work they are assigned, that work is done in a manner that is consistent with both worker and customer safety, and that ongoing control of the infrastructure is maintained. In consideration of the critical nature of these requirements, several jurisdictions have defined worker qualifications for MSPs operating within their geographic areas. Other jurisdictions have relied on the licensing or registration process for MSPs to insure that appropriately qualified workers are employed. This document will provide principles that might be employed in the development of worker qualification criteria and outline an example of one method of achieving that qualification.

Technical qualification of workers has generally been achieved through the use of a graduated series of levels through which a beginning worker must pass before being certified (or qualified) to perform all metering work. The number of levels and skills needed to pass through those levels varies among providers of metering services. The methods used to pass through levels, however, are based on training and experience in all cases with employee testing added in most cases to validate competence. Ongoing training or relicensing is often used to insure that workers remain qualified after their initial licensing. Actual determination of qualification levels may or may not be performed by the ARA, with some jurisdictions depending on the service provider to insure compliance.

In most jurisdictions, the qualified worker is required to carry identification showing his employment with the service provider. This identification may outline the level of qualification that the worker has achieved. Additionally, the worker may be required to wear a uniform that further identifies his employment with a registered service provider.

The following example outlines a certification requirement that utilizes three levels of worker qualification. Those levels are described in sufficient detail to provide an understanding of the essential skills that should be considered. That understanding, coupled with a consideration of existing utility skills and requirements, may be utilized in development of requirements appropriate to a jurisdiction.

Example of Worker Qualification Levels

1. Level 1 – Entry Level

1.1 Metering Types and Voltages

This level includes single phase or network socket-based meters, 300 volts phase-to-phase maximum and does not include transformer rated meters. Communication wiring must be outside of energized meter panels.

1.2. Work to be Performed

Level 1 Meter Workers can install, remove and replace 120/240 volt single phase or 120/208 volt network, self-contained meters in standard meter sockets or socket meters in A base adapters and inspect the installation in accordance with the requirements set forth in the Meter Installation Section of this document.

Connections of communication conductors must be outside the energized meter panels.

1.3 Safety Skills

1.3.1 Ability to perform the job in accordance with the MSP's procedures and safety rules

1.3.2. Ability to identify electrical hazards and to perform work to avoid such hazards

1.3.3 Ability to comply with OSHA requirements and safety codes

1.3.4 On-site use of personal protective equipment

1.3.5 The ability to identify services within their qualifications.

1.4 Essential Technical Skills

1.4.1 Understanding of single phase and network electrical metering

1.4.2 Understanding of electric distribution safety procedures

1.4.3 Ability to identify energy diversion or tampering related to this level of meter work

1.4.4 Ability to install and remove damaged and undamaged electric meters in this level of meter work

1.4.5 Understanding of meter panels, socket layouts for the metering conditions related to this Level of meter work

1.4.6 Ability to read meters used in this class

1.4.7 Ability to properly use tools appropriate to the work in this class

1.4.8 Ability to connect meter communications external to the meter panel

- 1.4.9 Ability to initialize meter communication modules that do not call for the modification of metering constants or parameters using meter configuration software.

1.5. Developing Essential Technical and Safety Skills

- 1.5.1. MSPs will develop and implement a program to train their workers to perform Level 1 meter work safely and properly.
- 1.5.2 MSPs will develop and implement a classroom training program (minimum of 40 hours) to train their workers to perform Level 1 meter work safely and properly. They should also provide a minimum of forty (40) hours of on the job training (OJT) working with a meter worker having at least 1 year experience at level 1 or 6 months experience at level 2 or 3.

1.6 Employee Certification

- 1.6.1 Employees will be certified by their employers, based on prior experience or the successful completion of the MSP's training program.
- 1.6.2 For the Utility and MSP employees currently employed, or employed within the last 3 years, in a position where they performed these functions for at least 6 months, the requirements are reduced to successful completion of the MSP's classroom training program.

2 Level 2 – Intermediate Level

2.1 Metering Types and Voltages

This Level includes all meter types in Level 1. Level 2 also includes single phase, two-phase, poly-phase, safety socket, standard socket-based meters, A-base, K-base, and transformer rated meters with internal diagnostics used on services with up to 600 volts phase to phase. Communication wiring may be routed inside the panel and work can be in and around energized circuits.

2.2 Work to be Performed

- 2.2.1 In addition to Level 1 Meter Work, Level 2 Meter Workers can install, remove, replace inspect, program, and test singlephase, network, polyphase, and transformer rated meters, including those with internal diagnostics, and/or meter driven load control devices on services with up to 600 volts phase to phase and can operate test-bypass facilities or determine if installations without bypass facilities are safe

to disconnect. These workers may also work on communication wiring that is installed inside the panel, and can work in and around energized circuits.

- 2.2.2 Level 2 Meter Workers may not install, alter, maintain or replace wiring between the meter, test switch, test block, and associated equipment. Any metering problems with test switches, panel wiring or transformers and transformer wiring detected by a Level 2 Worker will be verified and/or corrected by a Level 3 Meter Worker.

2.3. Safety Skills

- 2.3.1 All Safety Skills required for a Level 1 Worker, plus the following:
- 2.3.2 Electrical safety knowledge and work skills appropriate for three-phase metering on services with up to 600 Volts phase-to-phase.

2.4. Essential Technical Skills

- 2.4.1 All Technical Skills required for Level 1 Workers, plus the following:
- 2.4.2 Ability to work with transformer rated meters.
- 2.4.3 Ability to perform phase rotation assessments and wiring verification.
- 2.4.4 Ability to operate test-bypass facilities or test switches.
- 2.4.5 Ability to perform work required to route communication wiring to the meter through energized panels.
- 2.4.6 Ability to understand, interpret, and identify diagnostic messages from solid state meters and to take appropriate action based on those messages.
- 2.4.7 Ability to perform meter accuracy tests at the customer site using semi-automatic meter test equipment.

2.5 Developing Essential Technical and Safety Skills

Meter Service Providers will develop and implement a class room training program (80 hours) to train their workers to perform Level 2 meter work safely and properly, including a minimum of 500 hours of on the job training (“OJT”) working with a meter worker having at least 2 year experience performing at Level 2 or 3 meter work.

2.6. Employee Certification

Employees will be certified by their employers, based on successfully completing the MSP’s training program.

2.7. Experience Requirements

Minimum experience requirements that must be demonstrated prior to qualification as a Level 2 Meter Worker.

2.7.1. Successfully completing the Meter Service Provider training program and 12 months OJT working with a Level 2 or Level 3 meter worker who has at least 24 months experience.

or

2.7.2. If an employee has a two or four year degree in a related subject, the requirements are reduced to successful completion of Meter Service Provider training program and 4 months OJT working with a Level 2 or Level 3 meter worker having at least 24 months of experience.

or

2.7.3. If the entry level experience of any employee is that of a journeyman electrician, journeyman electric metering worker, or journeyman utility power line worker, the requirements are reduced to successful completion of the MSP's training program.

3. Level 3 – Advanced Level

3.1. Metering Types and Voltages

This Level includes all meter types in Levels 1 and 2 plus transformer rated installations where the primary voltage exceeds 600 Volts phase to phase and installations where compensated metering is required.

3.2 Work to be Performed

Level 3 Meter Workers can install, remove, replace, inspect, repair, program, and test any meters and associated equipment.

3.3 Safety Skill

3.3.1. All Safety Skills required for Level 2 Workers plus the following:

3.3.2 Ability to recognize and understand electrical hazards and complexities associated with metering switchboards, instrument transformers, testing meters, and maintaining meters in environments associated with high operating voltages.

3.4 Essential Technical Skills

- 3.4.1 All of the Technical Skills required for Level 2 Workers plus the following:
- 3.4.2 Ability to perform work on metering panels.
- 3.4.3 Ability to understand the operating characteristics of metering transformers and how to operate test switches.
- 3.4.4 Ability to perform calibration, repair, retrofit, troubleshooting, and data collection on all electric meters.
- 3.4.5 Ability to install, maintain, and program advanced metering types, including: time of use meters, interval recorders, real time pricing meters, compensated meters, remote communicating meters, and meter driven load control devices.

3.5 Developing Essential Technical and Safety Skills

- 3.5.1 Meter Service Provider's will develop and implement a classroom training program (40 hours) to train their workers to perform Level 3 meter work safely and properly.

The training must include a minimum of 6 months of on the job training (OJT) working with a Level 3 meter worker having at least 6 months experience at Level 3.

Meter Reading & Data Service Provider Qualifications

Introduction

The MRSP and the MDSP are required to meet minimum qualifications and requirements as specified herein and as set by the ARA in order to perform services in the area of jurisdiction. Service providers that receive a license to provide service, but plan to provide such services only through a sub-contractor(s), shall also ensure that its sub-contractor(s) meet these same minimum qualifications and requirements.

Meter Reading Service Providers Requirements

An MRSP must comply with the requirements listed below:

Entity Requirements

1. The MRSP must use trained and qualified employees and have a training program for new employees.
 - a. MRSPs will develop and implement a program to train their workers to perform meter reading and to work safely and properly. Training may also include a required minimum number of hours of on-the-job training with a qualified meter reading worker.
 - b. Employees will be qualified by their employers, based on prior experience or through the use of a training / testing program.
2. The MRSP must have hardware and software systems in place to obtain meter readings, perform on-site validation, and send readings to an MDSP in a mutually agreed upon format. However, if a MRSP does not have a contractual relationship with the MDSP, the exchange of meter data shall be done in compliance with the Data Transactions described in the Meter Usage Data Elements Section of this document.
3. The MRSP must have documentation of its systems and operating procedures.
4. The MRSP must have security systems in place to protect its systems from unauthorized physical or electronic entry or tampering.
5. MRSP employees who perform meter reading work at a customer site are required to have appropriate identification, indicating the worker's employer and possibly the type of work the employee is qualified to perform. This identification must be carried by the employee whenever doing meter reading work in the field.

Meter Reading Worker Qualifications

The following meter-reading worker qualifications are required for a meter reading worker to perform field based unbundled electricity meter reading services.

Work Skills

Meter Reading Workers must be able to accurately read visual display meters and/or read meters via a form of electronic communication using a computerized device, such as a handheld terminal, as applicable.

Safety Skills

- a. Ability to identify and work safely around electrical hazards.
- b. Performance of functions in compliance with MRSP's procedures and safety rules.
- c. Ability to comply with applicable OSHA requirements and other safety requirements as necessary
- d. Use of personal protective equipment while on site
- e. Knowledge of electric distribution safety procedures

Essential Technical Skills

- a. General knowledge of electrical watt-hour metering
- b. Ability to identify energy diversion or tampering
- c. Ability to identify damaged and undamaged meters
- d. Ability to read meters
- e. Ability to properly use tools appropriate to this work

Meter Data Service Providers Requirements

An MDSP must comply with the requirements listed below:

Entity Requirements

1. The MDSP shall validate, edit, and estimate data, if necessary, pursuant to the rules of validation, editing and estimation as described herein.
2. The MDSP shall provide meter reads to the Energy Supplier, the Utility and the other market participants as necessary, using the applicable protocol.
3. The MDSP is to maintain a number of the most recent consecutive months of customer usage data as specified by the ARA.

Meter Data Service Provider Qualifications

1. If an entity is approved to operate as an MDSP in another state, whose standards meet or exceed the ARA's standards, the entity must provide documentation of such approval. A prospective MDSP must

- provide the ARA, for the jurisdiction in which services are to be offered, with documentation that it meets the requirements below.
- a. The MDSP must utilize trained and qualified employees and a training program for new employees.
 - b. The MDSP must have hardware and software systems in place to receive meter readings; perform customer association, validation, editing, and estimation; and provide readings in the appropriate protocol.
 - c. The MDSP must have documentation of its systems and standard operating procedures.
 - d. The MDSP must have security systems in place to protect its systems from unauthorized physical or electronic entry or tampering.
 - e. MDSP must have a disaster recovery plan to restore service to a level that meets normal business requirements. Restoration from a minor disruption, such as a computer hardware failure, is to occur within 4 hours. Restoration from a major disruption, such as a natural disaster, is to occur within 24 hours. These time-frames apply unless times are otherwise specified by the ARA.
2. Prospective MDSPs must have successfully performed a data exchange test as required and as described below. Documentation of the results of the performance test shall be retained and presented to the ARA as necessary.
 - a. Receive raw meter reading data;
 - b. Perform customer association, validation, editing, and estimation; and
 - c. Exchange data with applicable market participants in the appropriate protocol.
 3. Suppliers that wish to receive a license for MDSP service, but plan to provide such services only through a subcontractor, shall demonstrate how the Supplier will ensure that its subcontractor(s) will meet the functional requirements in sections 1 and 2 above.

Inquiry And Complaint Resolution

Introduction

The following section details the inquiry and complaint resolution process in relation to metering issues. The section includes information on meter test costs, resolution of billing errors, disputes between the Utility, MSP, Energy Supplier, and/or customer.

Resolution of Billing Errors

If any entity providing unbundled electric meter services knows of any condition affecting the customer's meter or meter usage data that has resulted in billing errors, or discovers such a condition in the course of an investigation, it shall advise the customer and all entities serving the customer. The responsible entity providing unbundled electric meter services shall implement appropriate corrective action as set forth in this document.

Disputes between a Utility and an MSP Concerning an Unbundled Electric Meter

Disputes between any entity providing unbundled electric meter services and the Utility concerning an unbundled electricity metering location shall be handled through the dispute resolution process set forth in the Disputes Between the Utility and the Meter Service Provider Section of this document, through another mutually acceptable dispute resolution processes, or through the ARA.

Customer Complaints

1. Receipt of Complaints

- a. If a customer directs a complaint concerning an unbundled electricity metering location to the Utility, the Utility shall inform the customer of their right to the complaint handling procedures of the responsible entity that is providing unbundled electric meter services to that location and its right to present unresolved complaints to the ARA.

- b. If a customer directs a complaint concerning an unbundled electricity metering location to the entity responsible for the location, that entity must respond in accordance with the complaint handling procedures it has filed with the ARA.

2. Resolution of Complaints

- a. When the entity responsible for providing electric meter services informs the customer of its response to the complaint and the complaint is not satisfactorily resolved, they shall inform the customers of the ARA complaint handling procedures and the address and telephone number of this authority.

- b. If a customer is unable to reach a satisfactory resolution of a dispute with the entity providing unbundled electric meter services, the customer may file a formal complaint, either orally or in writing, with the ARA.

Meter Testing Costs

In cases where an accuracy test of the meter is required to resolve a dispute between a Utility, an entity providing unbundled electric meter services, Energy Supplier, and/or a customer, the following shall apply:

1. **Meter Tests Inaccurately**
If the meter is found to register outside of the ARA mandated tolerances, the cost of the test will be the responsibility of the party owning the meter.
2. **Meter Tests Accurately**
If the meter is found to register within the ARA mandated allowable limits, the cost of the test will be the responsibility of the party requesting the test.
3. **Evidence of Theft of Service**
If the test results in the identification of fraud or electricity theft by a customer, the cost of the test may be charged to the customer.

Auditing and Reporting

Introduction

Since there are many market participants that provide various unbundled electricity metering services, different types of audits may be necessary to assure compliance with the ARA rules and regulations. Work Function, Site, and Facility audits may be performed in conjunction with the establishment of licensing of a provider or as an ongoing market control function. Additionally, the unbundled electricity metering service provider may be responsible for any costs associated with audits required by the ARA. Special considerations may be necessary with facilities distant from the jurisdictional area of the ARA.

Audit Classifications

1. Work Function Audits consist of the witnessing of an installation, removal, or test of a meter to determine adherence to appropriate safety, environmental, and operational procedures and the appropriate use of test equipment, tools, and safety equipment.
 - a. Work Function Audits may be required by the ARA on the first group of installations of any new Meter Service Provider.
 - b. Additional audits may be required by the ARA using a statistically generated random selection plan once a service provider has established qualification.
2. Site Audits consist of an examination of an individual metering point (Service Delivery Point) to determine that the metering is registering properly and installed within specification.
 - a. Site Audits may be witnessed by or performed or representatives of the ARA or the Utility. Other market participants with an interest may witness the audit.
 - b. Site Audits should be generated in accordance with a statistically generated random selection plan that is based on the number of sites supported by a particular Meter Service Provider
3. Facility Audits - Meter Test Facility (Shop) – A Facility audit of a Meter Test Facility is the examination of the test facility to determine that meter equipment is processed in a technically competent and controlled fashion.
 - a. Audits of MSP meter testing facilities may include, but are not limited to:
 1. Compliance with all applicable standards
 2. Traceability of calibrations
 3. Ongoing training and qualifications of workers
 4. Documentation, to include procedures and processes
 5. Implementation of in-service test plans

- b. These audits may be specified and performed by the ARA in response to complaints received, in consideration of Site Audit results or in accordance with a schedule defined by the ARA.
4. Facility audits – Meter Reading Service Provider’s Facilities – A facility Audit of a Meter Reading Service Provider’s Facility is an examination of that facility to determine that meter reading data is being collected, stored, secured, and distributed accurately and in accordance with recommended practices in this document.
- a. Audits of MRSP facilities may include but are not limited to the following:
 - 1. Ongoing training and qualifications of workers
 - 2. Compliance with applicable meter reading standards
 - 3. Documentation of operating procedures and processes
 - 4. Compliance with appropriate data security systems
 - b. These audits may be specified by and performed by the ARA in response to complaints received by market participants or in accordance with a schedule defined by the ARA.
5. Facility Audits - Meter Data Service Provider’s Facility – A Facility Audit of a Meter Data Service Provider’s Facility is the examination of that facility to insure that meter reading data is being processed and stored in accordance with recommended practices and that appropriate security of the data is maintained.
- a. Audits of MDSP facilities may include, but are not limited to the following:
 - 1. Implementation and compliance with all appropriate performance standards for data accuracy and timeliness.
 - 2. Application of VEE standards to include a review of raw and validated data, algorithm implementation, and employee training for manually editing or reviewing data.
 - 3. Appropriate storage of records including the archiving of raw, validated, and historical data.
 - 4. Security
 - 5. Disaster recovery plans
 - 6. Documentation to include procedures and processes
 - b. These audits may be specified and performed by the ARA in response to complaints received by market participants or in accordance with a schedule defined by the ARA.

Responsibilities

- 1. Applicable Regulatory Authority
 - a. Responsibility for oversight and auditing of the metering infrastructure shall reside with the ARA that governs the licensing of providers of electric meter services. The ARA may designate a third party to perform the audit.

- b. The oversight will include, but not necessarily be limited to:
 - 1. Performance, or authorizing the performance, of site inspections of a metering installation.
 - 2. Reviews of procedures
 - 3. Facility Audits
 - 4. Witnessing of installations in progress
 - 5. Any other audits and reviews as deemed necessary
- 2. Utility
 - a. Shall cooperate with the audit process
 - b. May be required to perform audits as called upon by the ARA.
 - c. May perform audits of installations or facilities through which it receives data.
 - d. May request audits of installations of facilities through which it receives data.
- 3. Energy Service Providers
 - a. Shall cooperate with the audit process
 - b. May request audits of installations or facilities through which it receives data.
- 4. Meter Services Providers (MSPs), Meter Reading Service Providers (MRSPs) and Meter Data Services Providers (MDSPs)
 - a. Shall cooperate with the audit process.
 - b. Shall report all meter service and meter data service information in accordance with the provisions of this document.
 - c. Shall provide, upon request, routine and timely work schedules to the ARA or the Utility for the purpose of auditing meter installations, meter reading, and other on-site work.
 - d. May request audits of facilities through which it receives data.

Audit Reporting

- 1. A report will be provided at the conclusion of each audit by the entity conducting the audit.
 - a. The report will include a description of the scope of the audit.
 - b. Any shortcomings detected during the audit will be highlighted in the report.
 - 1. The entity being audited will have an opportunity to comment on the audit report. Such comments will be included in the final report.
 - 2. The report will be distributed to the ARA, the Utility and any entity that provides electric meter services to the account.
 - 3. All parties must take precautions to safeguard any confidential information that may be included in audit reports. Where these reports are made public, the audited party should have the opportunity to identify such information that it regards as

confidential and to request that such information be purged from the published reports.

Disputes Between the Utility and the Meter Service Provider

Introduction

The following practice describes the principal points that need to be included in the Governing Documents covering the Retail Access program to deal with the issue of disputes between MSPs and Utilities. This document does not address Complaints between the Customer and the Utility since various rules and guidelines already exist to govern these types of Complaints. In addition, this section does not address Complaints between Customers and MSPs. Other sections of the report describe the necessary consumer protections to govern this interchange and the specifics of a Customer Complaint resolution process should be left to the ARA.

Regulatory Policy Issues

As described more fully in the Preface, there are a number of regulatory policy issues that affect the business practices addressed in this document. The key policy issues impacting Dispute Resolution practices are identified below, along with implementation issues that were not resolved by the participants. Regulators and other policy-makers are encouraged to examine these issues before, or in conjunction with, considering the recommended business practices for a particular jurisdiction.

1. Role of the ARA in dispute resolution.
2. Where Dispute Resolution should be placed in the Governing Documents.
3. Which Alternative Dispute Resolution techniques should be available.
4. Payment expectations for disputed invoiced charges for services between Utilities and MSPs including how applicable interest should be applied.

Dispute Resolution Principles

The MSP and Utility shall use good faith and commercially reasonable efforts to informally resolve all disputes. Each MSP and Utility shall designate specific personnel to be responsible for responding to disputes under this practice.

There should be a single consistent dispute resolution process identified in Utility and MSP operating agreements and/or Utility tariffs. However, the details of dispute resolution practices can be spelled out in any Governing Document. Such documents should refer to or cite applicable law, remedies, and responsibilities for the cost of frivolous allegations. The parties may also

pursue other legal mechanisms to address disputes, but are encouraged to use the following practices first.

1. Any MSP or Utility may initiate the formal dispute resolution process by presenting a written description of the dispute, to the other party(ies) involved in the dispute, sent in a manner that will verify its receipt.
2. As soon as possible, but in no case more than 15 calendar days following receipt of the dispute, the receiving party must provide a written response to the party(ies) that initiated the dispute, with an alternative proposal for resolution if the party's(ies)' proposed resolution is deemed unacceptable; or, with the results of any informal resolution that may have been reached with the other party(ies) prior to that date.
3. If the initial exchange of written material (and perhaps verbal discussions) does not resolve the dispute, the party(ies) may request a meeting(s) to discuss the matter further. The responding party(ies) must agree to such a meeting(s) to be held within 15 calendar days following the request.
4. The parties may agree to use Alternative Dispute Resolution prior to or in lieu of petitioning the appropriate court or regulatory authority to intervene. This technique can reflect mutually agreed-upon time frames that may differ from those defined in the dispute resolution process. The parties must mutually agree on the selection of the neutral third party to administer Alternative Dispute Resolution.
5. The neutral third party providing Alternative Dispute Resolution shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner.
6. If a resolution is not obtained within 45 calendar days after the receipt of the initial dispute letter or the mutually agreed-upon time frame, either party may file the dispute with the appropriate court or regulatory authority for formal resolution.
7. If a MSP or Utility believes that special circumstances (such as an emergency involving public safety, system reliability or significant financial risk) exist that would require more expeditious resolution of a dispute than might be expected under the process described here, it may submit its dispute

directly to the state utility regulatory agency, with a copy provided to the other party(ies) involved in the dispute. The ARA will respond to such a filing by:

- a. expeditiously resolving the dispute; or
 - b. providing an interim resolution (subject to refund, etc.) and initiate the standard resolution process to provide a final solution
 - c. advising that the standard dispute resolution process described above be followed.
8. Absent agreement to the contrary, nothing shall restrict the rights of any party to file a Complaint with the ARA under relevant provisions of the state law.
 9. Absent agreement to the contrary, nothing shall restrict the rights of any party to file a dispute with FERC under relevant provisions of the Federal Power Act.
 10. Neither party should be required to give up its right to seek formal resolution of a dispute except as part of a signed, mutual agreement.

Control of Service Delivery Points

Introduction

Electric energy is delivered to a customer at a Service Delivery Point. Service Delivery Points may be metered or unmetered (as in the case of street lighting and bus shelters). Inaccurate or malfunctioning metering, missing or incorrect updates to data processing systems, unauthorized connections to the distribution system, and unknown or new unmetered service delivery points can adversely affect the ability to properly charge each customer for their usage. Control of Service Delivery Points implies that an entity will monitor all delivery points not qualifying for unmetered service to ensure metering is installed, metering information goes to appropriate parties, and billing accounts are established

Maintaining Control Of Service Delivery Points

1. For each jurisdiction, service providers must track meter installations, removals, and modifications for meters which they control, but a single entity (Central Monitoring Entity) should be used to track all information needed for control of all metered and unmetered Service Delivery Points, regardless of meter ownership. Entities providing electric meter services will be required to notify the Central Monitoring Entity of changes in metering that affect the disposition of the Service Delivery Point. Changes that require reporting include: meter replacements, meter removals, new installations at previously unmetered delivery points, and the creation or retirement of a Service Delivery Point.
2. Each metered Service Delivery Point must be uniquely identified. Unmetered Service Delivery Points may be grouped by contract.
3. All meters and associated equipment must be secured in accordance with the Sealing and Locking section of this document.
4. Site inspections, audits, and other field visits to metering installations will be used to verify the correlation between the unique Service Delivery Point Identifier, the customer, and meter (if metered site) of record. The results of these actions must be reported to the Central Monitoring Entity, depending on each jurisdiction's requirements.
5. Validation of usage data (as outlined in the Data Validation Editing and Estimating sections of this document) must take place to help identify anomalies in the metering system. Any anomalies must be reported to the Central Monitoring Entity, depending on each jurisdiction's requirements.
6. Compliance with actions described in the items above may be subject to audit.

Switching and Discontinuance

Switching of Metering Service Providers

Depending on the model selected in a jurisdiction, a customer currently enrolled or enrolling in Retail Access program may elect, or be required to switch to or from, unbundled electric meter services. In order to insure appropriate control of service delivery points, only the party responsible for electric meter services or the Utility can initiate the actual change in metering providers. Switching of meter providers should be done in a manner consistent with the process used for switching Energy Suppliers. In addition, the following meter specific requirements are applicable:

1. The outgoing meter provider will respond to an approved request with meter attribute data, historical meter usage data (if requested by the party responsible for electric meter services and if customer has approved release of this data), and any requirements for a joint meeting at the customer's premises to perform the work necessary to change service providers.

Depending on the unbundled electricity metering model, a switch to unbundled meter service may require a change in meter ownership. This may be accomplished by either a physical switch or ownership transfer of the meter.

2. If a switch in metering providers entails the physical switching of a meter and the incoming meter provider will perform the meter exchanges, the following shall apply:
 - a. The incoming metering provider shall remove and return the existing meter to the meter owner within ten (10) business days (unless another date is agreed upon).
 - b. The meter shall be returned to the outgoing service provider in the same condition it was in prior to removal.
 - c. The cost of removal and return of the meter(s) shall be negotiated between the market participants.
 - d. The incoming meter provider becomes responsible for the meter and meter usage data at the time that the outgoing meter provider's meter is removed.
 - e. At a minimum, a visual or validated automated final reading shall be taken to effect the switch of meter providers.
3. If a switch in meter providers requires a transfer of ownership of the meter:
 - a. Meter ownership and meter provider responsibility shall transfer on the switch date at the time of the final reading. This assumes that the final reading is on the customer's switch date.

- b. Transfer of any meter passwords and identification of protocols required to read the meter(s) must be accomplished by the outgoing meter provider in a time frame appropriate to integration into the incoming suppliers systems prior to the next regularly scheduled cycle meter reading date.
 - c. All parties shall cooperate to facilitate the switching of metering providers when meter ownership is transferred. This would include but not be limited to data necessary to the maintenance of applicable test programs.
6. For a switch in meter providers that does not include a change in meter ownership:
- a. Meter provider responsibility shall transfer at midnight at the beginning of the effective date.
 - b. Transfer of any meter passwords and identification of protocols required to read the meter(s) must be accomplished by the outgoing meter provider in a time frame appropriate to integration into the incoming suppliers systems prior to the next regularly scheduled cycle meter reading date.
7. If an entity responsible for any unbundled electric meter service is dropping a customer, that entity shall notify the all applicable market participants of the intended termination at least 30 calendar days prior to the drop date. In situations where meter exchanges are required on large multi-metered accounts or where a number of accounts are involved earlier notification may be necessary.

Customer Requested Termination of Electric Service

In cases where a customer is receiving unbundled electricity metering services and they decide to terminate electric service (move out), the following shall apply:

1. The Utility must be notified of a customer's intention to terminate all electric service. Upon receipt of that notification from the customer, the Utility will notify the party responsible for electric meter services of the intended termination date.
2. The party responsible for electric meter services will confirm receipt of the request within one (1) business day of receipt of the request.
3. The party responsible for electric meter services will take a final meter reading on the termination date and report the final reading within two (2) business days. If required by the Utility, the party responsible for electric meter services will also remove the meter and secure the location on the termination date.

Utility Initiated Disconnection of Electric Service

A customer may have their electric service terminated by the Utility for non-payment of regulated utility services. Only the Utility can terminate service for non-payment of regulated utility services. In cases where that customer is receiving unbundled electric meter services, the following shall apply:

1. The Utility must notify the party responsible for electric meter services of the disconnection date.
2. The party responsible for electric meter services will make arrangements with the Utility to obtain a final read of the meter prior to disconnection.
3. The Utility will disconnect service, and secure the location.

Note: Only the Utility can reconnect service or authorize the reconnection of service once it has been terminated for non-payment.

Default of an MSP

Under certain conditions, it may be necessary to initiate a process to discontinue the certification of an MSP. The ARA, along with the Utility and other market participants should develop regulations or guidelines to address the necessary policy issues regarding the default of an MSP. The following is a listing of examples that may require these actions to occur:

1. Where an MSP exits the market without making arrangements for continuing service of its customers.
2. Where an MSP routinely compromises the safety, security, or operational reliability of the Utility's transmission and/or distribution system.
3. Where there is evidence of metering tampering by the MSP.
4. Where there is evidence that the MSP has altered metering equipment under control of the Utility (e.g.: instrument transformers, wiring).
5. Where the MSP fails to comply with the provisions of the Utility's tariff.
6. Where the ARA determines that the MSP is no longer eligible to provide unbundled electricity metering service.

Record Keeping Requirements

Introduction

The purpose of this section is to provide guidance on the types of meter data that must be maintained, the duration of time it must be kept, and the responsibilities of the various entities relative to record keeping. It is anticipated that multiple entities will maintain metering and site data to support the metering function and to insure that all sites for which they have responsibility are, and remain, correctly metered. In addition, a single entity (the Central Monitoring Entity) may be called upon to maintain some basic set of data for all sites, regardless of meter ownership in compliance with the Control of Service Delivery Points section of this document. These record keeping requirements were also developed to support fundamental revenue cycle needs such as readings, billing adjustments, historical trending of usage for reading validation and estimation and other such functions. These functions, data elements and storage timeframes are developed in detail in subsequent sections of this document.

The guidelines set forth in this section apply to the data from or concerning energy meters, demand meters, interval data recorders, reactive energy meters, and any other meter types used in revenue billing.

Meter Acceptability

Any entity obtaining meter type approval in accordance with the provisions of this document shall maintain all data supporting such approval until one year after that meter type is removed from service.

Meter Lifecycle History

Meters shall be tracked from purchase through retirement. Meter records shall contain, at a minimum, information related to manufacturer, type, date of purchase, maintenance, and test history. Meter lifecycle records must be maintained for a period of time beyond retirement of that meter. This record retention period will be 3 years or some other period as dictated by local regulation. Examples of specific data elements to be recorded are provided below:

- Unique Site Identifier
- Meter ID
- Service address
- Date installed
- Results of last accuracy test

The entity responsible for providing metering services shall also maintain records describing the maintenance and accuracy of each of its meters for the life of the meter. Test results, like as-found and as-left accuracy, will be kept until superseded by a later test or as required by the ARA. Other data

elements that support billing adjustments (e.g. results of meter investigations) must be maintained for as long as that customer is served by the metering entity or for a term equal to that for which billing adjustments may be performed in that jurisdiction, whichever is longer, even if there has been a switch in service providers.

Site Configuration and Data Availability

The entity currently supplying metering services is responsible for maintaining site specific information that provides those details necessary to accurately describe the configuration, installed equipment, and data available for a site. This information must be maintained for as long as that customer is served by the metering entity or for a term equal to that for which billing adjustments may be performed in that jurisdiction, whichever is longer, even if there has been a switch in service providers. This stored information will be transferred to a successor meter provider upon contract termination with that customer subject to the timing standards established in the Data Provision and Retention section of this document. Examples of the type of data required for this purpose are listed below. A more inclusive list is provided in the Appendix 4 Non-Revenue Cycle Data Elements section of this document under Meter/Site Configuration Report.

Site Configuration

- Customer ID
- Unique Site Identifier
- Meter Form
- Meter Type
- Meter Capacity
- Locked / Sealed
- Socket / A Base
- CT / VT Definitions
- Compensation

Data Available

- Profile – Interval Size
- Demand – interval and Sub-Interval Size
- Reactive – Power Factor, Vars, VoltAmps (VA), Qs
- Pulse Outputs – Pulse Constant
- Rate Periods – if required for utility billing
- Reading Cycle
- Utility Service Classification / Tariff

Equipment Traceability

The entity providing metering services is responsible for validating the accuracy and traceability of field and shop test equipment used for testing meters and metering devices. The equipment to be tracked and associated

record keeping requirements are detailed in the Meter Testing section of this document under Traceability.

Current and Voltage Transformers

The entity having instrument transformers in service shall maintain records for such transformers that include, at a minimum, the manufacturer's name, type, and ratio. For each type, a record of specified accuracy must be retained for as long as that instrument transformer type is in service and a period of time after removal from service equal to the time for which billing adjustments may be made in that jurisdiction. Alternatively, results of individual accuracy tests may be substituted for manufacturer type accuracy specifications. See the Appendix One -- Demarcation Point Selection.

Meter Products and Equipment

Introduction

Meter products and equipment used for revenue determination must comply with applicable federal and industry standards as well as with the manufacturer's and national specifications for accuracy and functionality. (A listing of applicable standards and specifications follows.) Additionally, they must comply with any requirements of the ARA in the jurisdiction in which they will be used (see Meter Approval reference in this section).

Compatibility Criteria

Electrical & Physical Compatibility

- The meter used must be capable of measuring the electrical service for which it will be used.
- The meter must physically interface with the service delivery points of the Utility's distribution system.
- Consideration must be given to any existing control devices connected to the meter.

Displays

- The meter product or associated equipment shall provide an interface to the customer and/or Utility indicating energy consumption. For example, a visual display of kWh consumption would meet this criteria.

Service Entry Equipment

The MSP must adhere to applicable codes and standards for the local service area in which meter work is being performed. The MSP should refer to the local Utility for specific Utility requirements. All installed equipment must comply with the local Utility's requirements.

Each Utility shall make available a listing of compatible service entry equipment or meter service standards, and shall consider additions to its list at MSP request.

Existing Utility Meter Products and Equipment

Meter Products and Equipment currently in use by any Utility in a jurisdiction will continue to be acceptable for use, however, product anomalies detected while the product is in use as well as functionality, accuracy, and timing requirements, must be considered in determining continued acceptability. Where meter product type approval (an approval to use a specific manufacturer's model for revenue applications) by an ARA is not required, the Utility shall provide the ARA with a list of models purchased within the last five years that are currently being used and which meet marketplace requirements. These models should be posted as approved for revenue applications on the ARA website.

Meter Approval

The Meter Approval Process described here is intended to be used as a guideline for development of approval processes in jurisdictions that do not currently have a meter certification process in place. The level of detail, applicability of individual requirements, and need for additional requirements must be evaluated on an individual basis. The following elements are included: the meter product and equipment standards, the process by which meter products and equipment are certified, and the certification testing requirements. These standards apply to Meter Service Providers, who must use only certified meters in the state, and to meter manufacturers, who must certify that their Meter Products and Equipment comply with the national standards identified below.

Meter Service Designation

All equipment used in the metering of a Service Delivery Point shall be subject to the guidelines presented here. That equipment includes the following:

1. **Meter Product:** A device, including any optional circuit boards, devices, or modules housed within the enclosure, which measures, calculates, and/or records energy consumption data for the purpose of determining the financial obligation for an entity consuming energy.
2. **Meter Equipment:** Other devices, which are used in conjunction with the Meter Product to determine the financial obligation for the entity consuming energy. Note that current transformers (CTs) and voltage transformers (VTs), may be considered Meter Equipment
3. **Meter Type:** A set of meter products all having the same manufacturer's model or type designation.

Unbundled Electric Meter Product Registration

All unbundled electric meter products and equipment shall be, at a minimum, "self-certified" by the manufacturers using the Meter Performance Standards referenced in this section or as required by the ARA of the jurisdiction in which they will be used, unless they are currently in use by a Utility as described in Existing Utility Metering Products and Equipment section referenced earlier. The manufacturer, upon request from the ARA, will provide detailed test results.

Self-Certification Process

In order to certify their meter types, products, or equipment, manufacturers must follow the steps listed below:

1. Manufacturers must provide the following documentation:

- a. Either a cover letter, or a copy of the actual test report which documents the tests conducted, including results. If a letter is supplied, it must state that the test report is available and will be provided to any meter purchaser or ARA on request;
 - b. A completed Meter Product/Equipment Type self-certification form, including a list of the Types being certified as compliant with the performance requirements
- This documentation must be sent to the ARA, if required within that jurisdiction.
 - The ARA should send a notice to all interested parties of the pending application and provide a two (2) week comment period for interested parties to respond to the pending application.
 - Upon review of the application materials, the ARA will advise the meter manufacturer of the results and, if approved, may choose to post the product information on the ARA website.
 - The ARA has the right to audit or review the self-certification process.

Meter Performance Standards

This Section describes the meter product and equipment standards and the certification testing requirements. These standards apply to Meter Service Providers, who must use only certified meters in the state, and to meter manufacturers, who must certify that their meter products and equipment comply with the national standards identified below as well as other requirements listed in the Additional Requirements section below. This Section is used in conjunction with ANSI C12 to address concerns that are not currently addressed in that series of standards. All standards are living documents and may in the future incorporate some of the issues that are covered in the Additional Requirements heading of this Section. The recommendation is that as new versions of these standards are released, they should be reviewed and replace portions of this document as deemed appropriate.

1. ANSI and IEC Standards:

The following ANSI C12 Standards should be used, where applicable, to evaluate the performance of Meter Products and Equipment.

- 1.1. ANSI C12.1 – 1995 Code for Electricity Metering. This standard establishes acceptable performance criteria for evaluating new types of ac watt-hour meters, demand meters, demand registers, pulse

devices, instrument transformers, and auxiliary devices.

- 1.2. ANSI C12.6 - 1987 (R1996), Marking & Arrangement of Terminals for Phase Shifting Devices used in Metering. This standard applies to phase-shifting devices designed to provide the proper lagged voltages required for kVAR and kVA measurement.
- 1.3. ANSI C12.7 – 1993, Watt-hour Meter Sockets. This standard covers the general requirements and pertinent dimensions applicable to watt-hour meter sockets rated up to and including 600 V and up to and including 320 Amps continuous duty per socket opening.
- 1.4. ANSI C12.8 - 1981 (R1997), Test Blocks and Cabinets for Installation of Self-Contained A-Based Meters. This standard covers the dimensions, configurations, and functionality of test blocks and cabinets used with self-contained A-base watt-hour meters. General requirements are specified for: spacing, temperature rise, assembly bolts, connectors, test clips, barriers, and mounting holes.
- 1.5. ANSI C12.9 - 1993, Test Switches for Transformer-Rated Meters. This standard covers the dimensions, configurations, and functionality of meter test switches used for watt-hour meters used in conjunction with instrument transformers. Some general requirements covered include: material and workmanship, name plates, moveable parts, alternate switch arrangements, insulating barriers, wiring terminals, mounting, spacing, and dimensions.
- 1.6. ANSI C12.10, Electromechanical Watt-hour Meters. This standard covers the physical aspects of both detachable and bottom connected watt-hour meters and associated registers. These include ratings, internal wiring arrangements, pertinent dimensions, markings, and other general specifications.
- 1.7. ANSI C12.11 – 1987 (R1993) and ANSI C57.13, Instrument Transformers. These standards apply to instrument transformers used for revenue metering applications. Included in these standards are general requirements, metering accuracy, thermal ratings, and dimensions applicable to both voltage and current transformers.
- 1.8. ANSI C12.13 – 1991, Electronic TOU Registers for Electricity Meters. This standard covers electronic time-of-use registers for use in conjunction with electricity meters. It provides guidance on: 1) Numbers and format of displays, 2) Voltage, frequency, and temperature ratings, 3) Demand intervals, 4) Multiplying constants, 5) Timing systems, 6) Other general features, and 7)

Communication requirements. Specifications for the watt-hour meter on which these registers are mounted are not covered in this standard but can be found in other ANSI Standards described in this section.

- 1.9. ANSI C12.18 – 1996, Type 2 Optical Port (Optical Port Only). This standard details the criteria required for communications with an electronic metering device through an optical port. Application of the hardware section only of this standard is recommended for those meters with an Optical Port.

* Note- The data protocol requirements of ANSI C12.18, while recommended, are not mandatory.

- 1.10. ANSI C12.20 – 1998, 0.2% & 0.5% Accuracy Class Meters. This standard, in association with ANSI C12.1 provides performance requirements for 0.2 and 0.5% accuracy class meters.
- 1.11. IEC 61000-4-4 or ANSI C37.90.1 – 1989, Fast Transient Test. (Manufacturer's choice as to which standard to apply). This standard provides guidance on test procedures and surge levels to evaluate a meter's immunity to repetitive electrical fast transients. The object of this standard is to establish a common and reproducible basis for evaluating meter performance when subjected to repetitive fast transients (bursts), such as those originating from switching transients (interruption of inductive loads, relay contact bounce, etc.) on supply, signal, and control ports.
- 1.12. ANSI Z1.4 – 1993, Sampling Procedures and Tables for Inspection by Attributes. This standard, which corresponds to MIL-STD-105, establishes sampling plans and procedures for inspection by attributes that are frequently used in sample testing of in-service meters or acceptance testing of new meters. Sampling by attributes may be appropriate when a pass/fail criteria is used for product evaluation.
- 1.13. ANSI Z1.9 – 1993, Sampling Procedures and Tables for Inspection by Variables. This standard, which corresponds to the military standard MIL-STD-414 and is interchangeable with ISO/DIS 3951, establishes sampling plans and procedures for inspection by variables that are frequently used in sample testing of in-service meters or acceptance testing of new meters. Sampling by variables may be appropriate when a measure of a numerically based device parameter is used as a criteria for product evaluation.

2. **EEI Handbook for Electricity Metering**, Ninth Edition (1992). A

reference handbook that includes information on electricity metering theory, applications, accuracy, and safety.

3. **Applicable FCC Regulations.** Communication mechanisms used as part of the meter system must meet the applicable FCC regulations.

4. **Additional Requirements**

- 4.1 A Meter Product may be retrofitted with other devices or modules. Any device or module being installed in a Meter Product must be certified alone and in combination with the Meter Product being retrofitted. Prior to use, retrofitted Meter Products shall be tested for accuracy, labeled as retrofitted and by whom, and dated accordingly.
- 4.2 Any jurisdiction developing certification criteria for Metering Products or Equipment should consider the following:
 - 4.2.1 Any Meter Product or Equipment that has been rebuilt by other than the manufacturer or a facility maintaining a relationship with the manufacturer for the purpose of insuring quality of rebuilt products, may not totally conform to the original manufacturer's specifications.
 - 4.2.2 The use of parts or processes that do not totally conform to the original vintage parts or processes used by the manufacturer may affect the performance or reliability of the rebuilt product.
 - 4.2.3 Testing for accuracy using the methods outlined in this document for acceptance or on-going accuracy may not be sufficient to detect performance shifts.
- 4.3 Programmable meters used for revenue metering purposes must contain a mechanism that restricts access to stored information or operating parameters.

Certification Testing Requirements

1. Certification testing shall take place in a facility that has access to the necessary traceable equipment and competent personnel to perform the tests specified in this document.
2. Performance testing shall be conducted for new meter types and for major design changes to existing meter types. If an incremental change or changes are made to an existing meter type, applicable tests shall be performed to assure that Meter Products continue to meet the certification

testing requirements as stated in this section.

3. A test report shall be provided (if requested) documenting the tests and their results to the purchaser. The test report shall be signed by the manufacturer's representative(s) and shall include appropriate charts, graphs, and data recorded during testing.
4. Meter Products selected for certification testing shall be representative of production run Meter Products.
5. The following tests must be conducted using a single set of test samples: Insulation, Voltage Interruptions, Effect of High Voltage Line Surges, Effect of Fast Transient/Burst, Effect of Electrostatic Discharge (ESD), and ANSI C37.90.1 or IEC 61000-4-4 (Surge Withstand). Due to the potentially destructive nature of these tests, once subject to these tests, the Meter Products shall not be subject to other tests required under the ANSI C12 Series. The other tests required by ANSI C12.1 and C12.20 may be done either in parallel with each other (using multiple sets of test samples) or in sequence with each other (using a single set of test samples). All of these other tests do not need to be done on the same set of test samples, but must be done in accordance with ANSI requirements.
6. Meter Product samples selected for testing shall be kept for one year after the conclusion of testing. These test samples shall be made available during this period to any purchaser using these products as certified devices for inspection, if requested.
7. Meter Products which fail catastrophically during the test shall not be repaired or tested further, but can be analyzed to identify the cause of failure. This does not apply to a failure to meet an accuracy specification.
8. When the test samples fail to meet performance requirements and after any correction is made on the new test samples, all tests shall be re-started with the new test samples unless it can be demonstrated that the corrections did not have any affect on the results of performance tests not being repeated.
9. If requested by the purchaser, the manufacturer shall notify the purchaser of the certification test schedule for purchaser's test witnessing.
10. If more than a minimum number of samples are certification tested, the test results shall be based on and reported for all samples tested.

Meter Product Failure Definition

A Meter Product shall be designated as failed if any of the following events occur during or after any certification test:

1. Failure of the Meter Product to perform all functions as specified in a test procedure.
2. Failure of the Meter Product to meet the fundamental technical performance specifications as specified by the manufacturer. The fundamental performance must include safety, accuracy and reliability of the Meter Product, and any other functions included in the Meter Product.
 - Signs of physical damage as a result of a test procedure.
 - The occurrence of a loss of data or other unacceptable mode of operation for the Meter Product as a result of a test procedure.
 - Failures of hardware, firmware, or software, or a combination thereof.

Meter Type Certification Rejection Criteria

The meter type certification rejection will be based on the above mentioned standards, or failure to perform functionality specified by the manufacturer.

Identification of Non-Utility Meters

Introduction

There is presently no standard way to uniquely identify a meter across Utility boundaries. Manufacturer model and serial number are not guaranteed to provide a unique identifier, as utilities often request a specific serial number range from a manufacturer. This can lead to confusion as a Supplier will typically have customers in more than one Utility's service territory. Agreement on a uniform meter identification standard will reduce errors and associated costs. Following is a proposal for a unique meter numbering system that could be implemented to address this problem.

Identification of Non-Utility Meters

1. All meters must be clearly labeled with the name of the MSP or the owner as required by the local Utility.
2. All meters must be identified by a permanent unique meter identification number as assigned by the local Utility or in accordance with ANSI C12.10.
3. The meter number used for a service delivery point shall be assigned by the Utility or provided to the Utility by the entity providing metering services.
4. The meter identifier is intended to be used in all applicable data exchanges.

Meter Identifier for Non-Utility Meters

In cases in which the Utility does not assign the unique meter identification the following guidelines may be followed:

Meter Identifier Format: AABYYYYYYYYZZZZZ

1. Where AA is the meter test setup code;
2. Where B is an identifier for the meter manufacturer;
3. Where YYYYYYYYY is the manufacturer's serial number;
4. Where ZZZZZ is a user defined field, such as the Department of Energy's ID number or entity responsible for that meter.

Service Delivery Point Identifier for Locations with a Non-Utility Meter

The Service Delivery Point Identifier is intended to facilitate data exchange between parties and minimize transaction and development costs. When a

Service Delivery Point Identifier is used, the following process should be implemented.

1. A Service Delivery Point Identifier (SDP ID) for the Utility territory is a permanent, unique number (not required to be intelligent) used to facilitate communication in an unbundled electric market. The Service Delivery Point Identifier remains as long as the connection between the Utility system and the Customer physically exists.
2. Service Delivery Point IDs will be assigned by the Utility for each meter location (meter socket, A-base meter) for metered accounts that will be affected as part of the switching process the first time a customer switches to an Energy Supplier providing unbundled electricity metering services.

Note: Methods and procedures for the use of Service Delivery Points to identify and transfer data for totalized accounts have not been developed. These methods and procedures must be developed before implementing the use of Service Delivery Point Identifiers.

3. Service Delivery Point IDs for unmetered accounts will be assigned as part of the enrollment process the first time a customer with unmetered service delivery points switches to an Energy Supplier.
 - 1.1. Service Delivery Point IDs will be assigned at the contract level. It may not be necessary or appropriate to assign an individual ID to every Service Delivery Point.
 - 1.2. Service Delivery Point IDs established for unmetered contracts live past the contract term.
 - 1.3. An unmetered Service Delivery Point ID shall be retired if that Service Delivery Point ID becomes metered or upon removal of the equipment to which the ID refers.
4. If labeling a meter socket with the Service Delivery Point ID is required, the MSP is responsible for such labeling and following local Utility guidelines.
5. Proposed Format: 1-0-xxxxx-yyy...yy
 - 5.1. Where 1-0 is reserved for future use
 - 5.2. Where xxxxx is the Utility's Department of Energy ID number
 - 5.3. Where yyy...yy is up to a 29 character Utility assigned number that is permanent and unique within the Utility service territory.

Field Meter Work Site Inspections, Safety and Environmental

Introduction

This section identifies minimum safety and reporting requirements for the entities performing on-site fieldwork, which includes reading, installation, maintenance, and testing of meters and metering equipment. Note that CTs and VTs, as well as communication components, may be considered part of the metering system in some jurisdictions. Where visual inspections are required in the sections below, the scope of the inspection shall be limited to those areas where the meter worker is in the position to reasonably identify an irregular or unsafe condition.

Safety Related Inspection Requirements

In the course of performing meter work reasonable safety inspections must be completed. Meter work includes, but is not limited to, meter installation, replacement, maintenance, programming, and testing.

The following list is not intended to cover all possible situations that could be encountered by workers; rather the workers should identify these and other conditions if they pose a potential threat to safety and/or property.

Customer Life Support Inspection

1. It is the customer's responsibility to notify the Utility and suppliers of Metering and Energy Services of the presence of life support equipment at their premises.
2. If a customer's premises has a life support device or equipment and a life support seal or sticker appears on the meter, a life support seal or sticker (see Sealing and Locking Section) shall be reinstalled.
3. When a customer's account has been identified for customer life support, meter workers shall be cautious in performing meter work so as not to interrupt electric service to the customer's premises.
4. If service will be or is likely to be interrupted during meter work, the meter worker shall notify the customer and obtain the customer's consent prior to performing work.
5. If it is determined that life support equipment is in use on a customer's premises and the customer's record does not contain life support information, appropriate parties shall be notified of the presence of life support equipment. It remains, however, the responsibility of the customer to arrange for life support status on their account.

Electrical Hazards Visual Inspection

Electrical hazards are conditions that pose an immediate threat to personal safety. Visual checks for various potential electrical hazards shall be performed. All metering installations should conform to the governing body's electric service requirements. The following list, which is not all inclusive, outlines examples of deficiencies that should be identified.

- Exposed, loose, or burned wiring,
- Damaged socket jaws,
- Auto-bypass load jaws still hot when meter removed,
- Missing panels,
- Loose or broken service insulators,
- Missing meter,
- Improper grounding conditions,
- Fused neutral conductor,
- Lightning damage,
- Vandalism,
- Defective service switch/disconnect.

Physical Dangers Visual Inspection

Physical dangers are conditions that could pose a threat to personal safety. Visual checks for various potential physical dangers shall be performed. The following list, which is not all inclusive, outlines examples of deficiencies that should be identified.

- Slippery or uneven walking surfaces,
- Unsafe stairs, railings, or platforms,
- Debris or materials stored in or above the meter working space,
- Volatile, caustic, or acidic chemicals, asbestos, lead, loud noises or biological agents in the area,
- Inadequate or unsafe meter access,
- Loose meter mounting, undue vibration,
- Inability to securely seal meters,
- Unleveled meters,
- Vicious or unpredictable animals, insects, snakes, rodents or other vermin in or around doors and electrical panels.

Safety-Related Reporting Requirements

The appropriate parties must be notified if the worker is unable to correct safety-related hazardous or dangerous conditions, relating to the metering installation, found on a customer's premises.

1. Safety-related hazardous conditions which pose an immediate threat to personal safety should be reported without delay to the customer, Utility, Suppliers, and other parties that may have a material interest in the defect

or condition, including local inspection authorities, as appropriate. The site shall not be left unattended until the condition is made safe.

- 2 Safety-related dangerous conditions which do not pose an immediate threat to personal safety should be reported using the appropriate protocol within one (1) business day of discovery to the customer and other parties that may have a material interest in the defect or condition, including local inspection authorities, as appropriate.

Meter Related Inspection Requirements

The following inspections are completed by the worker prior to performing meter work on site. Meter work includes, but is not limited to, meter installation, replacement, maintenance, programming, and testing.

Visually inspect meter sites for the conditions listed below. These inspections are intended to ensure that installed meters are correctly identified and have the correct characteristics for the type of service provided to the customer.

1. Meter Verification - Ensure meter is properly identified, approved for use and of proper size and type for the service to be monitored.
2. Meter Reading - Verify that the meter can be read visually and/or remotely.
3. Instrument Transformer-rated Meter Inspection - Verify the billing constants, secondary wiring and CTs and VTs for appropriate ratios/accuracy/voltage class/etc., when these instrument transformers are accessible. When instrument transformers are not accessible, mark as such and notify appropriate parties to arrange for verification if necessary.
4. Pole-Mounted Meter Inspection - Check for open cutouts, blown fuses, and broken grounding electrode conductors. Notify the appropriate parties of the defects.
5. Pad-Mounted Meter Inspection - Ensure the meter enclosure is mounted securely, is lockable, exterior warning labels are properly attached, and all metering electrical and grounding connections are secured and properly made.

Inspection for Theft of Service

To minimize the effects of meter tampering and energy diversion, the cooperation of all market participants is necessary. The worker needs to be aware of techniques used by individuals to divert energy, and how they can assist in the minimization of theft and the apprehension of violators.

Visually inspect meter sites for the conditions listed below. These inspections are intended to identify the most obvious forms of energy theft and to provide basic information for additional investigations. It is important to acknowledge that not all indications of theft can, or even should, be described here. Rather, the worker should, at a minimum, be able to identify and report these conditions.

1. Verify general condition of the metering installation:
 - 1.1. Irregularities in the service conductors, unauthorized connection in the line side of the service entrance, unauthorized seals and unsealed or improperly sealed conditions, jumpers across current leads, tampering with the meter register.
 - 1.2. Inspect for small holes in the meter cover, dial pointer alignment, register mesh, and register gears, meter disk alignment wear or scratches on the meter.
2. When meter security is compromised or there is evidence of meter tampering, or energy theft, the condition must be documented and reported to appropriate parties within the time frame established in Meter Service Agreement to determine appropriate action.

Sealing and Locking

Introduction

Meter Products and Equipment are generally sealed and possibly locked to insure accountability for accuracy and functionality, to minimize theft of service, maximize its detection and to assist in providing for public safety. Considerable effort is expended in the control and use of seals and keys to insure that appropriate security is maintained. This section outlines some of the requirements that will assist in providing that level of security.

Meter Securing and Sealing

1. Detachable meters shall be secured into the socket.
2. A-Base meters shall be secured to prevent unauthorized access to their terminal block.
3. At a minimum, the meter shall be secured with a seal. The use of locks will depend on local conditions.
4. If required in the Utility's territory, the meter worker shall ensure that a sticker indicating the service voltage is in place on the meter panel near the meter before leaving the site.
5. For the purposes of this section, meter installations will be classified as:
 - 5.1. Low Potential – which consists of all installations where the line voltage does not exceed 600 volts,
 - 5.2. Intermediate Potential – where the line voltage exceeds 600 volts but does not exceed the threshold where the utility practice prohibits entry into live enclosures,
 - 5.3. High Potential – where the voltage equals or exceeds the threshold where the utility practice prohibits entry into live enclosures.
6. The MSP must follow the Utility's procedure for access to High Potential CTs, VTs, and their enclosures.
 - 6.1. Where these enclosures are locked, the Utility will provide the lock.
 - 6.2 The MSP must coordinate with the Utility for appropriate system conditions to be established and for the lock to be removed.

Meter Seals

1. The seal used for sealing the meter system shall identify the company servicing the meter and/or installation.

- 1.1. The seal shall contain the name of the company and a unique identification or serial number.
- 1.2. The use of a company logo shall not be considered sufficient identification for seals.
- 1.3. Equipment with existing seals that do not meet these criteria are to be grandfathered.
2. The seal shall not contain lead.
3. The seal must provide security such that any entry or attempted entry to the meter equipment will result in easily identified, non-repairable damage to the seal.
4. Any entity using seals must have established procedures to control access and distribution of seals, insuring that they are available only to authorized parties.
5. In jurisdictions where customers on life support are identified through an identification at the meter:
 - 5.1. The standard physical identification marker for a customer's premises that has a life support device or equipment shall be a life support seal or sticker.
 - 5.2. The seal or sticker must be easily identified as indicating life support.
 - 5.3. Examples of such seals or stickers are those colored white with red lettering or red with white lettering, having a caduceus symbol on it.

Meter Locks

1. Locking of meters shall be consistent with the existing policies of the local Utility.
2. Where meters have been locked by the Utility, meters installed by suppliers of unbundled electricity metering services must also be locked.
3. Exceptions to this requirement may result from agreements between the Utility and the MSP or from local policies.
4. Where a locked meter is being replaced, the service provider installing the new meter must coordinate with the entity controlling the existing equipment to arrange for a mutually acceptable means of removing the lock.

5. When an MSP locks a meter and/or associated equipment, the lock used must be operable by the utility in the event that emergency service work is required.
6. The following are examples of how the operability requirements may be met:
 - 6.1. The Utility may publish a list of approved locks for use within its service territory that are operable by the standard utility key, but whose keys will not operate Utility locks. These locks may be used by MSPs in place of the standard Utility lock.
 - 6.2. The MSP may provide a dual lock arrangement that allows operation by either a Utility lock or a lock provided by the MSP
7. Service providers shall have established procedures to maintain control of keys to meter locks that minimize the possibility of unauthorized duplication or use.
8. Locking of a previously unlocked installation may be required if a theft of service condition is suspected or detected.
9. The MSP shall install such locks in response to a legitimate concern by any entity having revenue dependent on the registration of the meter.

Meter Panel and Associated Equipment Securing and Sealing

The meter panel and any enclosures housing equipment associated with the metering for an installation shall be secured with a seal and/or possibly a lock, using the same criteria described for locking of the meter. This requirement applies to CT/VT enclosures, profile recorders, relays, totalizers, and any other equipment that is used to accomplish the revenue metering function.

Meter Socket Covering, Securing, and Sealing

When a site is left with an empty, energized meter socket, the socket shall be covered with a non-conductive cover and shall be secured with a seal and/or possibly a lock.

Meter Security for Programmable Meters

1. Programmable meters used for revenue metering purposes must contain a mechanism that provides restricted access to stored information or operating parameters.
 - 1.1. This mechanism must be utilized to prevent unauthorized access to internal registers and unauthorized modifications of the meter data and program.

1.2. The most prevalent method used to restrict access is the use of passwords.

Timing and Coordination

Introduction

The following section addresses issues of meter site access and the scheduling of joint activities .

Access

Customers must provide the Utility, MSP, and/or MRSP with clear access to the metering site for the purpose of meter reading, inspecting, auditing, and installation, maintenance, or recovery of metering equipment.

Coordination and Timing

1. For scheduled work where a site visit requires a joint meeting, a minimum of 2 business days of notice will be given.
 - 1.1. Each party must arrive no later than 30 minutes after the scheduled time.
 - 1.2. Failure of any party to arrive within the appropriate time frame will be cause for rescheduling the visit and the offending party may be charged for the cost associated with the missed visit.
2. Where the customer suffers a service interruption and coordination between Utility and MSP is required to restore service, immediate notice must be given, and the Utility and MSP shall cooperate to restore service as soon as possible.
3. Each Utility should develop guidelines for situations that will require site visits.

Meter Installation

Introduction

The following are the minimum required procedures that a meter worker must follow when installing and/or removing meters. These procedures do not necessarily include all facets of a meter installation, however, they do provide sufficient detail to allow development of procedures that are appropriate to individual jurisdictions. Coordination between the MSP and the Utility may be required in both the development of procedures and the maintenance of the infrastructure.

Pre-Installation

Verify type and size of metering is appropriate for site.

Meter Replacement

1. Perform all inspections as described in the Field Meter Work Site Inspection, Safety and Environmental Section of this document.
2. Take closing read on existing meter.
3. Ensure load has been dropped to a safe level.
4. Remove existing meter. Meter is to be returned to the owner in accordance with the guidelines in the Switching and Discontinuance Section of this document.
5. Verify/install/attach the meter multiplier, if required by the local jurisdiction. Install new meter.
6. Compare the indicated load of the new meter with the load present at the time of the installation.
7. Seal and / or lock the meter in accordance with the Sealing and Locking Section of this document.
8. Take initial meter read.
9. Complete record keeping requirements and insure notification of appropriate parties in accordance with the Record Keeping Requirements Section of this document.

Meter Installation at New Sites

1. A new meter installation is defined as the first time a service delivery point is metered.
2. Installation of a meter(s) on a newly constructed premise where the

customer has decided, prior to service connection, to sign up for retail access service must be treated differently than a change meter order. The appropriate market participants shall work together to complete new meter installations and service connection in a timely manner, consistent with the customer's interest and public safety.

3. There are four (4) key elements which must be completed prior to an Utility authorizing a new meter set:
 - 3.1 Customer's application on file with the Utility,
 - 3.2 A request for service under a retail access arrangement accepted by the Utility,
 - 3.3 Utility's receipt of an electrical site inspection clearance , and
 - 3.4 Service completion, or coordination for energizing service.

The Utility will issue an authorization to set a new meter and notify the MSP if a joint meet is required (e.g. for instrument transformer rated metering). If a joint meet is required, the requirements of the Timing and Coordination Section of this document shall apply. If no joint meet is required necessary, the MSP shall set the new meter within two (2) working days of the Utility notification. The Utility may require that proper metering be in place prior to energizing.

Should an MSP install a new meter without authorization from the Utility, the Utility may initiate a process to terminate the certification of that meter provider pending a formal investigation by the ARA.

Rewires and Service Upgrades

If a customer rewires or upgrades their electrical service and/or metering equipment, the MSP, upon notification to the Utility of intent, may remove the meter before the work on metering equipment starts if required. Reinstallation of the meter is subject to the same requirements of Meter Installation at New Sites reference in this Section.

Should a meter service provider reinstall an existing meter in newly replaced metering equipment without authorization from the governing body, the governing body may initiate a process to terminate that meter service provider's certification.

Locking Device

Insure appropriate locking device is in place in accordance with the Sealing and Locking Section of this document.

Replacement of Existing / Defective Equipment

Introduction

This section outlines the responsibilities of market participants in the replacement of defective metering equipment.

MSP Responsibilities

Unless otherwise specified in this document, the MSP is responsible for repairing or replacing any inoperative or defective metering product or equipment that is under its control within 3 business days of the identification of a defect, or receipt of notice of such a defect. Any repair made to inoperative or defective equipment must be tested in accordance with local requirements. Instances where this time frame cannot be met must be identified, and a plan to execute the required changes provided.

1. It shall be the responsibility of the MSP to secure the cooperation of the customer if any action is required on the part of the customer in order to affect the repair or replacement.
2. If a hazardous condition exists or if the customer suffers a service interruption as a result of a malfunction of the metering equipment, the MSP shall endeavor to repair the customer's service within 24 hours.
 - 2.1. Both MSP and Utility shall coordinate where joint efforts are required to effect a repair within the 24 hour time frame.
 - 2.2. Both MSP and Utility will designate an emergency response contact name and telephone number for the other party to contact in cases where the coordination is required and normal data communications are inoperative or would not affect repair of the customer's service within the 24 hour time frame.
3. When meter security is compromised or there is evidence of meter tampering, or energy theft, the condition must be documented and reported to appropriate parties within the time frame established in Meter Service Agreement to determine appropriate action.
4. When a metering device is to be disposed of, consideration should be given to the presence of hazardous materials such as mercury or chemically based power sources (batteries) within the device. Disposal shall be performed in accordance with all local, state, and federal environmental requirements.

Utility Responsibilities

1. In situations where the MSP does not respond within the agreed upon time or 3 business days, the Utility may replace the meter installed by a

supplier of unbundled electricity metering services with a Utility owned meter until such time as the meter provider can make arrangements to have the meter replaced with an appropriate device. Costs associated with the Utility provision and replacement of meters under these circumstances are the responsibility of the entity providing metering services.

2. If a hazardous condition exists, or if the customer suffers a service interruption as a result of a malfunction of the metering equipment, the Utility shall cooperate with the MSP's repair efforts so as to repair the customer's service within 24 hours.
 - 2.1. Both MSP and Utility shall coordinate where joint efforts are required to effect a repair within the 24 hour timeframe.
 - 2.2. Both MSP and Utility will designate an emergency response contact name and telephone number for the other party to contact in cases where the coordination is required and normal data communications are inoperative or would not affect repair of the customer's service within the 24 hour timeframe.
3. If the Utility discovers the hazardous condition or interruption of the customer's service, the Utility may effect the repair itself and bill the entity responsible for metering service, or notify the Energy Supplier of the need to do so.
 - 3.1. The Utility will notify the entity responsible for metering services of the hazardous condition or repaired site within 24 hours.
 - 3.2. If an emergency exists that requires the Utility to disconnect service to the customer in order to protect health and safety, the Utility shall notify the entity responsible for metering services.
 - 3.3. If a theft of service condition exists, the Utility may correct the condition, remove and tag the existing meter and any associated evidence of meter tampering, and install and secure a properly registering meter. All interested parties must be notified of detected theft of service conditions consistent with the timeframes established in the jurisdiction in which the theft condition is detected.

Returning Meters

When the MSP removes a meter, it is to be returned to the meter's owner . The meter should be returned in the same condition as found prior to removal. The meter must be returned to its owner within ten (10) business days of removal

Meter Testing

Introduction

Meters which record energy consumption that are used to determine the financial obligation of market participants, must perform in accordance with appropriate accuracy standards when installed and through their lifetime. In keeping with this requirement, meters received from a manufacturer must be validated for registration accuracy prior to installation. Once installed, meter accuracy must be monitored through a program designed to track the performance of the population of meters by testing a portion of the population on a scheduled or statistical basis. All testing must be performed using test methods that properly set up test conditions and make the measurements that determine meter performance possible. Equipment used to perform these tests must be calibrated and traceable to (based on) nationally acceptable standard units of measurement in order to produce valid/certified test results. This section provides guidance on the establishment of appropriate calibrations through traceable calibrations, methods used in the establishment of test conditions and determination of performance, appropriate action for acceptance testing, and methods used for in-service testing. It is only through careful attention to the guidelines in this section that the accuracy of the metering infrastructure can be assured.

Traceability

Traceability refers to the process by which an assigned value of measurement is compared, directly or indirectly, through a series of calibrations (or comparisons) to the value established by the National Institute of Standards and Technology as the standard value.

Equipment Covered

All equipment used in the measurement of meter accuracy or in the establishment of test conditions for the determination of meter accuracy shall be calibrated and traceable to the National Institute of Standards and Technology (NIST). This equipment includes, but is not limited to:

- Watthour Standards
- VAR Hour Standards
- VA Hour Standards
- Voltmeters
- Ammeters
- Power Meters
- Counters or timers

Direct Traceability

Where possible, all measurements are to be traceable to NIST through comparison of the specific parameter being measured to a standard based on that same parameter.

Path to NIST

Traceability implies that the instrument has been directly compared with a national standard or that it has been compared with other instruments that are based on an unbroken chain of comparison to a national standard.

1. Direct comparison implies that no other instruments have been used that might have degraded the accuracy of the comparison
 - 1.1. A frequency or time standard may, for example, be directly compared with the frequency of WWVB, which is a radio signal run by NIST.
 - 1.2. A direct comparison offers the highest level of accuracy, since it minimizes the uncertainties induced by the inclusion of other instruments.
2. The use of a metrology laboratory implies that there is no direct comparison of the instrument under test to a national standard, but that intermediate instruments are used that are based on a comparison to a national standard.
 - 2.1. The manufacturer of an instrument may offer calibration services that provide traceability to NIST.
 - 2.2. There are a number of independent calibration laboratories that may also offer traceability to NIST.
 - 2.3. Generally, the more removed the final calibration is from the national standard, the greater the level of uncertainty in the final calibration.

Levels of Precision

1. The calibration of an instrument implies that tests have been performed to certify that the device measures the parameter on which the calibration is based to a specified accuracy.
 - 1.1. The manufacturer of the instrument provides specifications that indicate the largest error that may be introduced into a measurement by the device itself.
 - 1.2. Actual tests performed with the calibrated instrument may contain errors in excess of the instrument error due to test conditions, test methods, and associated equipment.
 - 1.3. Calibration test results providing correction factors at specific test points may be applied to a standard to allow use in applications requiring accuracy higher than the manufacturer's specification.

- 1.4. In applying the correction factors, care must be taken to insure that any other elements affecting registration accuracy, such as temperature, operating conditions, and long term drift, are carefully controlled to insure that the correction factors are appropriate.
- 1.5. Multiple tests at each test point may be required to insure that the measurement is repeatable.
- 1.6. Application of correction factors to the calibration of standards is normally performed in a standardizing laboratory by individuals thoroughly familiar with metrology.
- 1.7. At each point in a chain of comparisons to a national standard, the possible errors in the standard device shall be considered in determining the accuracy of the device under test.
- 1.8. Determination of a device's compliance with published specifications implies a calibration with a standard having a higher accuracy than the device under test by a ratio of at least four to one.
- 1.9. Where calibrations are performed with standards which cannot achieve the four to one ratio of accuracy, one of the following may apply:
 - 1.9.1. The standard has higher accuracy than the device under test.
 - The corrected accuracy of the standard must be considered in the determination of compliance of the device under test to published specifications.
 - The calibration data and an analysis of calibration uncertainties must be submitted to the ARA for approval before using the instrument in revenue metering applications, if required.
 - 1.9.2. The standard does not have a higher accuracy than the device under test.
 - The specified accuracy of the device under test will be derated to reflect the accuracy possible with a calibration by the selected standard.
 - The device under test will not be used in application requiring higher than the derated accuracy.

- 1.10. Total uncertainties introduced by intermediate calibrations shall not exceed the maximum uncertainty required for the calibration of the final device (in most cases an energy meter at a customer site) to required accuracy specifications.

Calibration Intervals

1. All traceable instruments must be calibrated at regular intervals.
 - 1.1. The interval of calibration shall not exceed the shorter of the manufacturer's recommendations or one year.
 - 1.2. Standards or test boards used in laboratories or shops for the direct calibration of customer meters should be point checked by a standard meter weekly. This check is not to be considered as a calibration, but rather an indication that there has not been a change in performance of the standard or test board.

Records

1. The testing facility shall maintain records for each instrument having calibrations traceable to NIST
2. Calibration records must include a calibration history of the instrument, including dates of calibrations, entity performing the calibration, instruments used in the calibration, and the results of the calibration.
3. Calibration records must be maintained for a period necessary to support any customer meter usage disputes.
4. Any repairs to the instrument must be documented and included in the calibration records.
5. Each instrument used in the calibration of meters must carry a calibration sticker with the calibration date and the date that the instrument is due for calibration clearly marked.
6. Each instrument should be accompanied with a certificate of calibration.

Test Methods

Introduction

The following section provides guidance on testing of both electro-mechanical and electronic meters, with a focus on establishing appropriate test conditions and determination of the performance of an individual meter. The methods described in this section may be used in performance of acceptance and in-service testing.

Energy Meters

1. Multistator meters should be tested and adjusted using one of the following methods:
 - 1.1. With all current circuits connected in series, and potential circuits in parallel.
 - 1.1.1. They may be tested and adjusted using each stator as a single phase meter, with all potential circuits energized. In this case, a balance test must be performed to insure appropriate registration on each stator. The final registration must be determined with all stators driven to insure that there is no interaction between stators.
 - 1.2. With individual current and potential coils energized from independent sources that simulate the service that the meter will be used to monitor.
 - 1.3. Using the customer's load.
2. Meters having multiple electromechanical rate registers, which record alternately, shall be tested separately at light load for each register train.
3. As-found tests of watt-hour meters shall be made with the cover on, where possible, and with registers, pulse initiators, and any internal attachments that were used in service in place.
4. As-left tests shall be made on meters which are to be re-installed or which are to remain in service after replacement of any internal component or adjustment.

Determination of watt-hour Meter Performance

A tolerance of 0.10 percent of reading shall be allowed for instrumentation and observation errors in the determination of percentage registration of watt-hour meters. Such tolerance shall not be included in the determination of meter performance for meters under selective and variable interval tests.

1. A meter shall be considered to be "Not Registering" if for any reason it is found not registering at both the light load and heavy load test points.
2. A meter shall be considered to be "Indeterminate" if the registration accuracy test results are not repeatable.
3. The final average percentage registration of a watthour meter shall be determined through consideration of both heavy load and light load accuracy. Following are two examples of methods for this determination:
 - 3.1. Multiply the test results at heavy load by four, add the test results at light load and divide the total by five.
 - 3.2. Add the test results at heavy load to the test results at light load and divide by two.
 - 3.3. Other mechanisms may also be considered acceptable.
4. A watthour meter which integrates the computed iron and copper losses of power transformers and feeder cables together with the customer's use of service shall be adjusted, if necessary, in consideration of the power transformer and line losses.

Watt-hour Meter Creep

1. Electromechanical meters
 - 1.1. No watt-hour meter shall be placed in service if the rotor turns continuously with all potential coils energized at service voltage and no load current flowing through the meter.
2. Electronic Meters
 - 2.1. No watthour meter shall be placed in service if it does not conform to ANSI C12.16-1991, Section 10.1.1, Test No. 1 – No Load which states:
 - 2.1.1. The Meter register or display shall not change more than +/- 1 least significant digit with the voltage circuits energized and the current circuits de-energized for a duration of 24 hours.
 - 2.2. Creep testing must be part of the approval process for new metering products. Due to the long time frame defined in the specification, creep testing does not need to be performed on a production or acceptance test basis, but may be part of a complaint test if there is suspicion that the meter is creeping.

Test Loads

1. All watt-hour meters shall be tested within 5 percent of the rated voltage or in accordance with manufacturer recommendations and 1.0 power factor at two load points as specified below:

1.1. Heavy load.

1.1.1. Self-contained meters with an “ampere rating” on the nameplate, shall be tested with a load of between 60 percent and 110 percent of the “ampere rating”

1.1.2. Self contained Class 60, Class 100, Class 200, Class 320, and Class 400 meters with a “test amperes” rating on the nameplate shall be tested with a load of between 80 percent and 120 percent of the “test amperes”

1.1.3. Transformer rated meters shall be tested at approximately 100 percent of the secondary rating of the current transformers or at the test amperes of the meter.

1.2. Light load.

1.2.1. Self-contained meters shall be tested with a load of between 5 and 10 percent of the “ampere rating” or “test amperes”

1.2.2. Transformer rated meters shall be tested with a load of approximately 10 percent of the secondary rating of the current transformers or at 10 percent of the test amperes of the meter.

1.3. An exception may be made for electronic wathour meters which may be tested using a single load point if the following conditions are met:

1.3.1. The meter uses a technology that does not provide separate adjustments for heavy and light load registration.

1.3.2. The meter type registration curve is linear

1.3.3. The meter type has been tested for linearity and correct registration at multiple points during an evaluation test

Watt-hour Meter Adjustment Limits

When a test of a watt-hour meter indicates that its registration is below 99% or above 101% , or as specified by local jurisdiction, at either heavy load or light load at 1.0 power factor, the percentage registration of the meter shall be adjusted to within these limits, as closely as practicable to the condition of zero error.

Some electronic meters do not have adjustments for registration that are available outside of manufacturer's facilities. These meters are to be removed from service if their accuracy falls outside of acceptable limits.

Demand Meters and Registers

Electromechanical demand meters or registers are those meters or registers which perform a demand measurement using an electromechanical timing mechanism, a gear train or other mechanical means of demand registration, or a thermal element to integrate power over a period of time. These devices include registers that are internally mounted on meters as well as stand alone devices. Each device using such mechanisms must be tested and possibly adjusted in accordance with the provisions of this section.

Electronic demand meters, devices, or registers are those meters, registers, or devices using an electronic timing mechanism in conjunction with an electronic means of registering energy use and calculating demand based on energy and time. These devices include electronic profile recorders, electronic demand registers for electromechanical meters, electronic totalizing demand meters, and fully electronic energy / demand meters. These devices are calibrated for watt-hour accuracy and should be tested to ensure demand functionality. They will not be subject to any additional accuracy testing requirements other than that necessary to establish performance prior to utilization for revenue metering purposes.

Rules for Testing Electromechanical Demand Meters and Registers

1. Tests of all demand meters and registers shall cover at least one demand interval and shall be started simultaneously with the demand interval of the demand meter or register. If a valid accuracy test result cannot be achieved in one interval, the test shall be performed to include two complete consecutive demand intervals.
2. When a demand meter or register is mechanically actuated by a watt-hour meter or demand-totalizing relay, the test may be made using the watt-hour meter, relay, or proper equivalent driving force to actuate the demand element.

Test Points for Demand Meters and Registers

1. All electromechanical demand meters and registers, except block-interval pulse-operated recording tape-type demand meters, shall be tested at between 40 and 100 percent of full scale, where possible.
2. When a demand meter or register is actuated by pulses from pulse initiators installed in one or more watt-hour meters or relays, each of the associated watt-hour meters and relays shall be caused to transmit at least 20 pulses to the demand meter or register or suitable counting device as a

check of the pulse initiators, associated equipment, and circuitry. The demand meter or register shall be tested as prescribed.

3. In testing a block-interval, pulse-operated recording tape-type demand meter, a comparison of the summation of the demands recorded on the demand meter tape for any specified period of time with the kilowatt-hour registration of the associated watt-hour meters during the same period of time may be considered as a test of the demand meter.
4. Where an electromechanical timing element also serves to keep a record of the time of day at which the demand occurs, it must be adjusted if it is in error more than plus or minus three minutes or as specified by local jurisdiction.
5. All electromechanical demand meters, devices, and registers shall be tested prior to installation or within 60 days after installation or as specified by local jurisdiction.

Determination of Demand Meter and Register Performance

1. The percentage registration of all demand meters and registers shall be determined in terms of half-scale value for one demand interval and shall indicate the percentage registration of the demand element alone. The watt-hour accuracy should be considered when reporting the percent registration of the demand meter.
2. The percentage registration of a demand meter or register shall be considered to be "Indeterminate" when the timing mechanism has become inoperative.

Electromechanical Demand Meter and Register Adjustment Limits

1. When a test of a demand meter or register indicates that its registration is below 99.0% or above 101.0% at half scale, or as specified by local jurisdiction, the demand meter or register shall be adjusted to register within these limits.
2. Demand meters or registers which are found to register incorrectly shall be corrected or removed from service.
3. Block-interval demand meters or registers which do not properly reset to zero shall be corrected or removed from service.

Pulse Initiators

Pulse initiators are defined as any device that provides a change of state of a set of electrical contacts in response to the registration of a fixed quantity of energy. Pulse outputs are generally available as Form A (2 wire or KY) or Form C (3 wire or KYZ). Electromechanical meters may provide such a pulse

from a mechanical or electronic mechanism tied to disk rotation. Electronic meters or registers may develop such a pulse by continuously monitoring energy use and generating contact closures when a specific quantity of energy has been recorded.

1. When it is possible to check the operation of the pulse initiators by means of counters installed for that purpose, no other test need be made of the pulse initiators or their circuits.
2. Pulse initiators which are found to transmit an incorrect number of pulses shall be corrected or removed from service.

Records of Tests

1. Meter lifecycle records must be maintained for a period of time beyond retirement of that meter. This record retention period will be 3 years or some other period as dictated by local regulation.
2. The test record for each current transformer shall indicate the ratio correction factors and phase angles at 10 percent and 100 percent of rated primary current at such burdens as to give assurance of satisfactory in-service performance. The test record for each voltage transformer shall indicate the ratio correction factor and phase angle at normal utilization voltage and with such burdens as to give assurance of satisfactory in-service performance.
3. The test record for an instrument current or voltage transformer shall indicate the frequency, the ratio correction factor and phase angle for each burden at which the transformer was tested.
4. A test record shall be provided for each phasing transformer that includes voltage ratios between marked terminals.
5. The test record shall be retained while the transformer to which it applies remains in service at the specified location and becomes void upon the removal of such transformer.

Acceptance Testing

Introduction

In an effort to ensure the new meters perform at acceptable levels of accuracy, new meters must be validated for accuracy before use. This section provides guidance on methodologies that can be used to evaluate the accuracy of new meter shipments. Sampling, 100% testing, and acceptance of certified test results are discussed, along with pass/fail criteria for each method.

Watt-hour meter tests

1. No new watt-hour meter shall be placed in service if test results indicate a final average registration accuracy error of greater than 1% or as specified by the ARA.
2. Performance will be based on the registration of the energy measuring portion of the meter unless the meter is equipped with a mechanical demand measuring register. The evaluation of performance is described in the Test Methods Section of this document
3. Each new watt-hour meter shall be subject to a test program prior to installation. The test program must conform to one of the following:
 - 3.1. Complete testing of a shipment received from the manufacturer
 - 3.2. Sample testing of the shipment of products from the manufacturer.
 - 3.3 Where approved by the ARA, manufacturers' test documentation may be acceptable.
4. Sample testing will be acceptable in the following cases:
 - 4.1. Where the revenue associated with the energy registered monthly by the meter will represent a significant portion of the cost of testing of the meter.
 - 4.1.1. This is the situation with most residential and small commercial energy meters.
 - 4.2. Where the meters are purchased directly from a manufacturer or an authorized distribution agent that guarantees the performance of the meter and supplies a certificate of calibration traceable to NIST.
5. When a sampling method is used, that method should follow ANSI Z1.4-1993, Sampling Procedures and Tables for Inspection by Attributes or

ASQ Z1.9, Sampling Procedures and Tables for Inspection by Variables for Percent Defective.

- 5.1. Unless a sufficient history with a specific manufacturer and distributor has been developed, General Inspection Level II (as specified as ANSI Z1.4 – 1993) must be used.
 - 5.2. The Acceptable Quality Level (AQL) should not exceed 2.5.
 - 5.3. If the shipment fails to meet the specified AQL, the shipment may either be rejected and sent back to the manufacturer, or 100% tested with the meters not meeting standard being sent back to the manufacturer.
6. Where manufacturer's data is to be accepted, the following conditions must be met:
- 6.1. The meter must have been received in a box sealed by the manufacturer of the meter.
 - 6.2. The meter must be accompanied by a copy of the manufacturer's test report or Certificate of Calibration indicating the results of the final test.
 - 6.3. The manufacturer must have traceability to NIST as described in the Traceability Section of this document.
 - 6.4. Where required, the manufacturer must be approved to provide test data by the ARA.
7. Demand Measuring devices such as electronic recorders, electronic totalizing devices, and electronic registers will not be subject to incoming accuracy tests, but will be subject to checks to insure that no modifications to the design at the time of product approval have taken place that might affect performance.
- 7.1. Integrated metering devices that include demand, totalizing, and recording functions will also be subject to the checks described above.

In-Service Testing

Introduction

The primary purpose of the In-Service Test Program is to ensure that the meter population remains reliable and accurate. This program is designed to balance the benefits of reliability and accuracy with the costs of maintenance and testing. The program requires maintenance and testing, either periodically or according to a sampling plan. Service providers must establish maintenance and testing programs that meet or exceed the basic requirements set forth below. Determination of applicability of the program is dependent on local regulation.

Responsibilities

The entity responsible for providing meter installation and maintenance services is responsible for in-service testing of all meters under their control.

Test Requirements

All meters used for determination of parameters used for revenue purposes will be subject to in-service testing.

Demand Devices

1. Demand measuring devices using electromechanical methods will be subject to in-service testing.
2. Demand measuring devices that use electronic methods will not be subject to in-service testing
 - 2.1. Integrated devices that measure energy and demand will be subject to in-service testing only for the energy measuring portion of the device.
3. Electromechanical demand registers installed on watthour meters shall be tested each time the associated watthour meters are tested in conjunction with an In-Service Test Plan.
 - 3.1. Additionally, watthour meters associated with a demand register shall be tested each time the associated electromechanical demand register is tested in conjunction with an In-Service Test Plan.

Meter / Device Population Determination

1. Determination of test quantities under most test methods are dependent on the population of meters supported.
 - 1.1. Application of test methods for metering devices will be based solely on meters in service within a predefined geographical area such as a state.

2. Devices that have been identified as having performance issues do not need to be included in an In-Service test plan.
 - 2.1. Handling of these devices must be defined in a formal plan filed with the ARA.
3. The selection process for any of the test methods may provide more meters than required to account for difficulties in accessing metering locations.
4. The degree of revenue exposure based on potential meter performance issues may be considered in determining applicability of test programs as well as mitigation strategies when performance anomalies are detected.

Meter Performance

Meter performance will be determined in accordance with the methods set forth in the Test Methods Section of this document with the following exceptions:

1. All meters which are found to be indeterminate or not registering due to causes other than tampering, incorrect connections, overload, or physical damage originating from sources external to the meter shall be considered to have a final average registration outside 98 % to 102 % or as specified by the ARA.
2. Tests where evidence of tampering with the meter is detected shall not be included in any calculations of meter population performance.

Periodic Test Programs

A Periodic Test Program calls for the testing of every meter covered by the program at a set interval. Determination of applicability and of the appropriate interval between tests is dependent on local regulations.

1. Where such regulations do not exist, ANSI C12.1 – 1995, Section 5.1.4.3.1 may be used for guidance.
2. Some jurisdictions have adopted periodic test criteria that call for longer intervals between tests than specified in ANSI C12.1. These criteria have been found to offer appropriate control of the infrastructure while minimizing cost and are to be considered as acceptable.

Variable Interval Test Programs

A Variable Interval Test Program calls for testing a percentage of the installed base of meters each year. The number of meters tested is based on the

performance of that population. Determination of applicability and of the percentage of meters tested is dependent on local regulation.

1. Where such regulations do not exist, ANSI C12.1 – 1995 Section 5.1.4.3.2 may be used for guidance.
2. Some jurisdictions have adopted variable interval methods and criteria that result in fewer tests than specified in ANSI C12.1. These methods and criteria have been found to offer appropriate control of the infrastructure while minimizing cost and are considered to be acceptable.

Statistical Sampling Test Programs

A Statistical Sampling Test Plan calls for testing a portion of the meter population covered by the plan. The number of meters to be tested is determined through a statistically based sampling plan. Determination of applicability, sampling methodology, and quantity of tests required may be determined by local regulation.

1. Where such regulation does not exist, one of the following may be selected for guidance:
 - 1.1. ANSI C12.1 – 1995, Electricity Metering, Section 5.1.4.3.3
 - 1.2. ANSI Z1.4 – 1993, Sampling Procedures and Tables for Inspection by Attributes
 - 1.3. ANSI Z1.9, Sampling Procedures and Tables for Inspection by Variables
2. If ANSI Z1.4 or Z1.9 are selected as the basis for a Statistical Test Program, consideration must be given to the selection of appropriate segments and performance criteria that will insure that the meter population performs as desired.
 - 2.1. The segments must be selected in a manner that insures a reasonable level of homogeneity.
 - 2.2. Where segments include more than one meter type, there shall be some mechanism to identify poorly performing types.
 - 2.3. Consideration must be given to the statistical validity of results when a small number of samples of a particular type is selected for test.
3. Some jurisdictions have developed methodologies for selection and sample quantities that call for fewer tests than specified by ANSI C12.1. Those methods have been found to offer appropriate control of the infrastructure while reducing cost and are considered acceptable.

Reporting Requirements

Reports of In-Service tests of watt-hour meters shall be made available to the ARA each year in accordance with local requirements.

All reports of In-Service Tests are to include the number of meters tested, the number of meters found outside of limits, and the size of the population. Where appropriate, the reports should break down the population of meters by type and be accompanied by appropriate performance parameters for that type.

Where poorly performing types are being reported on, the report will be accompanied by a plan for handling that type.

The annual report must include data (such as progress of mitigation efforts) that might be appropriate for tracking of types that are excluded from In-Service Test Plans and covered by a poor performance action plan.

Performance Metrics

Introduction

This section defines the metrics for measuring performance in an unbundled electricity metering environment. These metrics are used in the Data Transaction and Exchange Section of this document.

The Timeliness Section defines when the measured time period begins and ends. The Time Stamp section defines when the data is available. The Percent Data Received section defines the formula for calculating the percent data received.

The data for the first billing cycle for an account will not be included in the metrics. The first billing cycle is excluded to give all parties sufficient time to set up the customer account in their systems. This is not to imply that the data is not to be sent for the first billing cycle, it is just excluded from the measurement.

The Percent Data Received, has two sub-sections. The Meter Level section is used to measure the performance of the MRSP in providing individual meter readings. The End-Use Customer Account Level is used to determine the performance of the MRSP for accounts with multiple meters. Account Level performance is required since readings for all the meters on the account must be received for the account to be billed without the use of estimation.

Timeliness

1. Timeliness and percent of data received shall be measured based on the first data delivered for that account after the scheduled meter read date for each meter.
2. Timeliness for Non-Revenue cycle data shall be measured based on the time the request for data is received until the time the prepared data is first sent.

Time Stamp

If an electronic data transfer is used, timeliness will be based on the time stamp of the data package sent.

If electronic data is posted, timeliness will be based on the time the data is available to be retrieved.

If a manual process is used such as E-mail, Fax, or Courier service, the time stamp will be based on the time the data is:

- Sent, if the receiving entity does not have electronic transfer capability.

- Received, if the sending entity does not have electronic transfer capability.

Percent Data Received

Data received by the MDSP from MRSP – The percent data received is generally indicative of the MRSP performance and is calculated as follows:

$$(\text{Data Received}/\text{Data Expected}) \times 100 = \text{Percent Data Received}$$

Meter Level – Data Expected is the total number of meter readings which are expected. Data Received is the total number of actual meter readings received.

End-Use Customer Account Level – Data Expected is the total number of customer accounts for which meter readings are expected. Data Received is the total number of customer accounts for which actual meter readings are received from all of the meters on the customer's account.

Data received by the Utility and Energy Suppliers and their designated Billing Agent(s) from MDSP – The percent data received is generally indicative of the MDSP performance and is calculated as follows:

$$(\text{Data Received}/\text{Data Expected}) \times 100 = \text{Percent Data Received}$$

Data Expected is the total number of customer accounts for which billing determinants should be received. Data Received is the total number of accounts for which billing determinates are received.

Meter Usage Data Collection

Meter usage data shall be collected in appropriate time frames and with appropriate parameters as to support tariff, wholesale settlement, and retail settlement requirements. Where automated meter reading mechanisms are used to achieve calendar date billing, the Utility will still receive its meter usage data on the cycle day unless, a mutually agreeable, alternative is arranged or designated by the ARA. Detailed requirements, such as specific timing and data elements, should be addressed in a metering service agreement between the market participants.

Collection of time differentiated data must be accomplished through devices that have internal clocks, the ability to synchronize those clocks to national standards, and the ability to check the time accuracy of internal clocks of devices under interrogation. The real time clocks of meter reading devices or data acquisition systems (handhelds, laptops, etc) must be synchronized to a reference that is traceable to NIST to an accuracy tolerance of +/- 1 minute. Such synchronization should occur before data collection at the beginning of

each day that data is being collected. The time accuracy tolerance of the meter is covered in the Test Methods section of this document.

After collection of the data, the MDSP or MRSP must associate the collected meter usage data with customer identifiers.

Data Provision and Retention

Introduction

This section provides guidance on the content of revenue cycle metering data that needs to be retained by providers and sent to market participants. Situations involving changes to the Service Delivery Point, opening and closing of accounts, and supplier or account number changes are examined and appropriate mechanisms for transmitting data under these conditions are provided.

Complete Billing Period Data

Data is normally sent for complete billing periods as defined by the recipient of the information.

1. Complete billing periods are usually based on a month or meter reading cycle.
2. If the transaction contains the initial read for a new account, the billing period starts with the initial read.
3. If the transaction contains the final read of an account, the billing period ends with the final read.

Account Number Change

If the Utility account number or the Energy Supplier account number changes during the billing period, the account numbers reported with meter data should include the old and new account numbers that applied during the billing period in which the change occurred. Subsequent transactions will contain only the new account number.

Service Delivery Point Change

When changes affecting the service delivery point occur (e.g., a meter change), the metering data before and after the change must be reported. Following a change the partial usage data may be transmitted in multiple data transactions or it may be sent as a single transaction at the end of the billing period, depending on the local jurisdiction.

Final Read

Metered data for a close of account (final read) will be provided within five (5) business days of the actual closing of the account.

Meter Usage Data Gaps

If a meter fails in service or is removed and temporarily replaced with a device that does not provide the same functionality, a data gap can occur. In these cases, metering data will be reported in the same manner as described for changes in the service delivery point, with the following exceptions:

1. The data for the period in which the metering equipment did not provide adequate information will be estimated in accordance with

the estimating techniques defined in the Validating, Editing, and Estimating Sections of this document.

2. The appropriate transaction will be issued indicating that the meter has been replaced. (See Non-Revenue Cycle Data Transactions in the Data Transactions & Exchange Section.)
3. The raw data from the replacement meter will be reported in a transaction appropriate for the data provided by that meter.
4. The MDSP will combine the data from the removed meter and from the meter that replaced it and will estimate the data not provided by the replacement meter in accordance with the guidelines presented in the Validating, Editing, and Estimating Sections of this document.
5. The combined data will be reported using a transaction appropriate for distribution validated data under the replacement meter's number.
6. Every effort must be made to insure that a meter appropriate for monitoring the account on a permanent basis is installed within one billing cycle.

Meter Service Provider Change

If there is a change in the responsible MRSP or MDSP, each of these providers must provide the data for the period in which he had responsibility for that meter.

1. The outgoing and incoming providers of metering services must make every effort to insure an orderly transition and the site remains continuously metered.
2. Where possible, the transition should be made on the cycle meter reading date.
3. Appropriate transaction(s) will be issued for the period in which the change occurred in the same manner as described for a change in the service delivery point.

Type of Meter Usage Data Required

Cumulative, Demand, and TOU data is to be provided in the manner described in the appropriate transaction listed in the Data Transactions Section of this document.

Interval Data

Interval data should be provided as energy (or reactive energy) per interval.

1. Demand, if required, can be calculated from the interval data by consideration of the interval time period.
 - a. The standard interval length will be chosen in a manner that supports the Utility tariff requirements and the billing requirements of the Energy Supplier.

2. All interval data must contain a time stamp for the beginning and end of the series of intervals.
 - a. All time stamps will be reported in GMT unless local arrangements are made for other labeling.
 - b. The time stated for a recording interval shall be the end of the interval.

Estimated Data

Estimated data must be identified as "Estimated" in the transactions.

1. The reason for estimation should be provided on receipt of a reasonable request.
2. If requested, the party which estimated the data must provide the estimation method used.

Totalization

Totalization may be performed on site or through addition of individual meter readings or interval data by back end systems. Validation of usage data from multi-metered accounts may be performed on either individual meters contributing to the totalized usage or on the totalized usage, dependent on the requirements of the Utility, the Energy Supplier, and local regulation.

1. Where totalization is performed on-site, the totalized usage data will be retrieved from the totalizer or recorder by the MRSP and processed by the MDSP as either cumulative data (with demand) or interval data.
2. Where totalization is done by back end systems, one of the following will apply:
 - a. The MDSP will develop the totals from individual meter or recorder profiles, apply the processes appropriate for validating, editing, and estimating to those totals, and produce the transactions that provide the information necessary for determining the billing determinates for the totalized usage. This data will be transmitted in a transaction appropriate to the transfer of totalized data.
 - b. The MDSP will apply the processes appropriate for validating, editing, and estimating to the individual meter data or recorder profiles, and produce transactions that provide the information necessary for determining the billing determinates developed for each of the individual meters. This data will be transmitted in individual transactions for each meter and will be further validated as totalized data by the user of the data or the MDSP in accordance with the requirements of the Energy Supplier and Utility.

3. A Meter Services Agreement between the market participants may be used to define the appropriate methods for handling of totalized data.

Curtailments

1. The MDSP must be informed by the Energy Supplier of curtailments that apply to both historical data and to current billing periods using a mechanism that insures timely notification to support verification of compliance with curtailment requirements.
2. Historical data from a period of curtailment should not be used to validate or estimate current data. Similarly, normal estimation rules may not be appropriate if data needs to be estimated for a curtailment period.
3. If the metering data for a billing period containing curtailment needs estimation, the application of validation, editing, and estimating techniques should be done collaboratively between the Energy Supplier, MDSP, and the Utility.

Retention of Validated Meter Reading Data

Validated Meter Data shall be retained such that it is readily available for as long as needed to support back billing and customer information in accordance with the ARA.

Data Adjustments

Resending and/or adjustment of previously transmitted data may arise from data maintenance activities (e.g., response to customer inquiries, the restoration or modification of data files, and response to problems with posted data) or meter maintenance activities (e.g., discovery of incorrect reads, crossed meters, non-registering meters, slow or fast meters, incorrect multipliers, etc.).

Timing

An MDSP should make corrected data available to the original recipients as soon as it is available, no matter when a correction is discovered in order to minimize impacts on bill adjustments, estimations, unaccounted-for-energy, and revenue assurance. It is the responsibility of the recipients to determine how to process the corrected data.

Adjustment/Correction Processing for Metered Accounts

Correction to Previously Sent Data

When corrections are made to previously sent data, the complete set of data pertaining to a meter and billing period should be resent (not just the corrected data points).

1. The corrected data must be flagged as adjusted.
2. If the corrected data is estimated, it must also be flagged as estimated.
3. When sending corrected data, each billing period for the affected meter should be in a distinct transaction.
4. While only the data for the affected billing period and meter needs to be resent, the entire billing period needs to be resent, with exactly the same time period as the original data. (For example, if the meter was originally read late for the end of a billing period, the resent data should cover the period that was actually reported, rather than for what the billing period should have been.)

Crossed Meters

In the case of "crossed meters", in which meter numbers have been incorrectly reported for sets of usage data, the MDSP will make the corrections necessary to correctly report the data, Service Delivery Point Identifier, meter identifier, and account identifier. The MDSP will then flag the data as adjusted and resend the data.

Reframing

Reframing refers to providing data for a corrected time period, usually when a customer's turn-on or turn-off occurs. When data is "reframed", all affected months must be cancelled and provided again. Appendix 2 provides examples of reframing for a number of anticipated situations.

Security / Control

Security

Security refers to the assurance that metering data, other than that which is visually displayed on the meter, can be retrieved by only authorized parties, at the desired time, has not been modified in transmission, and that the originating device has not been modified in such a manner as to affect the accuracy of the reported data.

1. All meters that can be read or programmed through a communications link must contain protection to guard against unauthorized access as discussed in the Sealing and Locking Section of this document.
2. Meter data transmission and processing shall have sufficient controls to insure that the data is delivered reliably and has not been modified nor accessed by unauthorized parties.

Direct Access

The MRSP shall have direct access to those meters that it has contracted to support. Direct access, as used here, refers to communication with the meter through an optical or other communications port for the purpose of modifying or examining operating parameters, retrieving metering data, or reading the visual display.

1. Direct access to the meter by the customer should be allowed only in those cases where proper security exists and interrogation of the meter by authorized parties is not hindered by contention at the communications port.
2. Real-time customer consumption information may be made available through the use of energy consumption pulses provided by the meter. These pulses are frequently used to drive customer load control systems.

Access to Retrieved Metering Data

Access to all retrieved metering data will be restricted to those entities for whom it is essential that access be made available to perform their function and those entities to whom the customer has authorized access. Where data is made available to entities requiring access to perform their function, such as Energy Suppliers, MSPs, and Utilities, the following shall apply:

1. Each entity will maintain, control, and secure its databases to limit access to authorized parties, as described in the Database Maintenance/Disaster Recovery Section of this document.

2. Access to data will be provided through the use of transactions as described in the Appendix 3 – Meter Usage Data Elements Section of this document.
3. At the transaction level, security responsibility will lie with the entity transmitting the transaction to insure that it is sent in a secure channel and only to those entities authorized for its receipt.
4. If transactions are posted for retrieval by authorized entities, the posting site must have sufficient controls to insure that only authorized entities gain access to those transactions.

Modifications to Configuration Data

Modifications to configuration data concerning meter hardware (operating parameters, hardware, tables, etc.) and the meter site configuration will originate only with the entity(ies) responsible for servicing of the metering site.

1. Generation of the transactions required to modify or update databases will be the responsibility of the entity designated as responsible for metering.
 - a. If the metering functions are sub-contracted to other service providers, the ultimate responsibility for transactions does not transfer to the sub-contractor.
2. The communication of data between the entity responsible for metering and any sub-contractors should be compliant with the standards set forth in this document, however, individual entities may use custom protocols as long as the security and timing requirements of this document are adhered to.

Historical Data

Historical data will be transferred to authorized entities only through the transactions defined in the Data Transactions Section of this document.

Access to Data

1. Customer Access – The customer shall have access to that data that is used in the determination of its bill.
 - a. If the bill is based on profile data, the customer shall be permitted access to that data.
 - b. Where the customer desires more detailed or frequent data than is used in development of its bill, he must contract with the Service Providers for its provision.

2. Authorization for Third Party Access – Third Party access to data will be provided only where authorized by the customer, as described in the Uniform Business Practices Document.

Database Maintenance

Introduction

Service Providers must maintain a database that, at a minimum, provides the necessary data needed to control the infrastructure and provide accurate metered or estimated usage data. This section describes the maintenance requirements for databases used for the tracking of service delivery points and for the storage and processing of usage data. The description of four databases in this document is not meant to require exactly four physical databases, but is just used as a means to describe the data requirements. Different database configurations are allowed as long as data requirements are met.

Data to be Maintained

Data maintenance obligations include, but are not limited to the following:

- Service Delivery Point Identification
- Installed Meter
- Meter characteristics
- Meter readings;
- Usage history

Site and Control Databases

A database containing site information, including but not limited to the service delivery point identifier, installed meters, and all service providers servicing that service delivery point shall be maintained by a single entity designated as a control entity by the ARA. This entity shall associate the service delivery point with meters attached to the distribution system in its jurisdiction to insure appropriate control of Service Delivery Points. The database used for this function (Control Database) may be used only for this function and need not be available for market purposes. The support of business functions shall be provided through Site Databases maintained by service providers servicing that customer. The data elements required for the Site Database shall be sufficient to support the transactions described later in this document.

The following shall apply to the control and modification of the Site and Control Databases:

1. Access to Site Database contents will be restricted to those entities for which it is essential that access be made available in order to perform their function.
2. The entity responsible for maintaining the Site Database will maintain, control, and secure the database to limit access to authorized parties.

3. Modifications to the Site Database will originate with the party responsible for making the changes (Energy Supplier, MDSP, MRSP, MSP, or Utility).
4. Generation of the transactions required for modifying or to update the Site Database will be the responsibility of the entity making the change.
5. The entities maintaining Site Databases shall be responsible for generating the transactions appropriate to insuring that the Control Database remains current.
6. Where automated electronic communication of transactions is required, each participant's system should automatically post the appropriate transactions to the entity maintaining the Control Database.
7. Where manual data transfer is used, a control system must be used to insure that the manually generated and received transactions have reached their destination.

Meter Configuration Database

The service providers supporting metering at a customer site must each maintain or have access to a database that contains the meter specific information needed to service the equipment at that site, collect the data from the meters or metering devices, and to process the data from the meter or meters at that site. Individual suppliers (such as MRSPs and MDSPs) may maintain only such data as is necessary to complete their portion of site support. The data maintained in the Meter Configuration Database must, at a minimum, be capable of fulfilling the transactions outlined under the Non-Revenue Cycle Transactions Data Elements Sections of this document. Any entity modifying site equipment or metering parameters must provide updates to all entities maintaining a Meter Configuration Database for that site in accordance with the timing and protocols given in the Non-Revenue Data Elements Section of this document.

The data elements to be maintained in the Meter Configuration Database include, but are not necessarily limited to the following:

- Service Point Identifier
- Meter number
- Meter manufacturer, type, ratings, etc.
- Meter programming information, including display tables, passwords, etc.
- Current and Voltage Transformers associated with the meter
- Other devices providing input to the meter
- Other devices receiving output from the meter

- Usage parameters provided by the meter
- Sealing and locking requirements
- Reading frequency or cycle requirements

Meter Usage Database

The ARA should designate which entity has responsibility for maintaining a database of usage data for its customers. The responsibility for maintaining this database may be subcontracted.

The Meter Usage Database must contain records of customers' usage segregated by billing periods or cycles and must be maintained for the period of time as designated by the ARA.

If service is discontinued, upon request the MDSP must transfer this data to the new supplier using the transactions outlined in this document and maintain its own records for the period of time designated by the ARA.

Reconciliation and Synchronization of Databases

Reconciliation or synchronization of the Control Database and the individually maintained Site Databases is to occur periodically or as required by the ARA. The following process is provided as an example:

- The entity maintaining the Control Database and the entities maintaining the Site Databases should each maintain a list of records that have been modified in the preceding year. Those lists will be used to selectively compare the databases.
- The comparison is to be performed by the entity responsible for maintaining the Control Database, with the data elements as required by the appropriate authority.
- The procedure will consist of comparing the stored data in the Control database with the data provided by the ESP or its agent for that particular record.
- Errors detected in this process will be manually reviewed for appropriate resolution before updates to the databases takes place.
- Disputes concerning the appropriate data will be resolved with an investigation in the same manner as described in other sections of this document.
- The entity maintaining the Control Database will provide a report on this process to the appropriate authority if required.

Periodic reconciliation of selected metering and billing data must be performed to insure consistency between entities.

This reconciliation need not be against the entire database, but may be the result of a statistical sampling program.

If a sampling program is used, the use of a sampling program must provide an AQL and confidence as designated by the appropriate authority.

The reconciliation will be performed by the entity maintaining the Control Database.

The entity maintaining the Site Database will provide a file, acceptably formatted, containing the data needed for the reconciliation at the request of the entity maintaining the Control Database.

If the entity maintaining the Site Database discontinues service to the site, it must maintain this data until after the annual reconciliation has been performed.

Inconsistencies, found in reconciling the databases, will result in the generation of an investigation request.

Resolution of these investigation requests will be subject to the same procedures as investigation requests against current issues.

The entity maintaining the Control Database will provide a report on this process to the ARA if required.

Disaster Recovery

All parties responsible for data transfer and maintenance shall have and maintain a disaster recovery plan that addresses data redundancy as well as hardware, power and communications failures.

Elements of a Disaster Recovery Plan

Each party responsible for data transfer and maintenance shall have and maintain a disaster recovery system that addresses the following areas:

- Backup Requirements
- Power Failures
- Communications Failures
- Redundancy of Records
- Hardware Failures

Adequacy of Disaster Recovery Plan

The disaster recovery plan is to be sufficient to restore service to a level that meets normal business requirements. Restoration from a minor disruption, such as a computer hardware failure, is to occur within 4 hours. Restoration from a major disruption, such as a natural disaster, is to occur within 24 hours. These time frames apply unless otherwise specified by the ARA.

In the Event of a Catastrophe

In the event of a catastrophe, such as an earthquake or hurricane, which precludes reading meters, the MDSP or party responsible for data collection should estimate and post the data. The estimated data will be reported separately in the performance report, and will not be included in any performance metrics calculations. In the event of meter failure where the meter is not accurately recording usage, the estimated data will be reported separately in the performance report, and will not be included in any performance metrics calculations.

Data Transaction and Exchange

Introduction

Meter data must be read, validated, edited, estimated, and disseminated to all appropriate parties in a timely fashion to meet market requirements for billing and settlement. This section provides data exchange and performance guidelines that apply to any entity providing unbundled meter reading or meter data service(s). Performance of those suppliers may be determined by application of the metrics provided here. Additionally, a series of recommended transactions are provided that should assist the market by providing some level of consistency across various jurisdictions. In applying these guidelines, it may be important to consider that in some states, the entities providing these unbundled electricity metering services are not affiliated with each other, or with the customer's energy supplier, and each may work directly with the customer; while in other states, these functions are performed by subcontractors.

Note: In applying the following metrics, recall that the term "Business days" is defined as Monday through Friday without consideration of holidays. Exclusions to these metrics for holidays shall be as defined in the individual tariffs of the local Utility.

Data Timeliness Guidelines – Meter Reading Data (Cycle & Off-Cycle reads)

When an MRSP is acting independently from the MDSP, the MRSP must perform appropriate customer association and validation prior to providing meter reading data to the MDSP. Reads must be provided to the responsible MDSP by 9:00 PM on the day the readings occurred, or as otherwise specified between contracting parties.

Data Timeliness Guidelines – Validated, Edited, & Estimated Meter Usage Data (Cycle & Off-Cycle reads)

The entity that is responsible for meter data services must retrieve the meter reading data for each meter or service delivery point, associate the data with the customer account, validate the data, and supply the data to appropriate parties within the time frames listed below, or as specified by the ARA.

1. Complete billing and usage data from a minimum of 80% of all accounts taking metering service from a meter service provider must be available to the market participants by no later than 11:59PM on the first business day following the scheduled meter reading date.
2. Complete billing and usage data from a minimum of 90% of all accounts taking metering service from a meter service provider must be available to the market participants by no later than 11:59PM on the second business day following the scheduled meter reading date.

3. Complete billing and usage data from a minimum of 99% of all accounts taking metering service from a meter service provider must be available to the market participants by no later than 11:59PM on the fifth business day following the scheduled meter reading date.

Note: In item 1 through 3 above, individual states and/or Utilities may have more stringent requirements in order to provide billing ready data to their Customer Information System during their billing window.

It is in the best interest of all affected parties to deliver and receive data in a timely fashion. To do this effectively requires collaboration of all parties to adequately maintain the systems and infrastructure related to metering information. Unless acceptability limits are established by the ARA, a suggested level of performance should be that no more than 10% of all required meter usage data shall be estimated per month and meter usage data for any one meter should not be estimated more than three times in a 12 month period. A failure to meet this guideline may result in the entity causing the failure to be cited for a failure to conform to performance metrics. Continued non-conformance with this guideline may result in initiation of a process to terminate the certification of the provider pending a formal investigation. There may be extenuating circumstances and/or natural phenomena, such as natural events or equipment failure that may cause this guideline to be exceeded. Should these circumstances exist, all affected parties require notification of any specific circumstances known to the meter service providers as to the cause of the issues and the expected course of action for resolution.

Exceptions To Data Timeliness Guidelines

Following a switch in providers where a meter change is involved the estimation performance guidelines are suspended for the first billing cycle

In the event of meter failure where the meter is not accurately recording usage and the unbundled electricity metering supplier responsible for providing validated, edited, and estimated meter usage data has no control over the meter, the estimated data is to be exempt from the timeliness and estimation performance guidelines provided that:

- A manual reading has verified that the meter has failed and there is no problem with the remote reading technology.
- The Energy Supplier or MSP has notified the Utility and other parties having revenue dependent on the meter reading of the failure in the meter or communications link.

- The meter, if defective, is replaced within the time constraints as outlined in the Replacement of Existing/Defective Equipment Section of this document.
- The provider of communications services, if communication is inoperative, is contacted for resolution of the defect within the time frame as outlined in the Replacement of Existing/Defective Equipment Section of this document. Note: The replacing of defective communications equipment may take longer than 24 hours stated because the MSP may be dependent on a local phone company to repair a phone line used for communications with the metering device.

Off-Cycle Data

Any off-cycle meter reading shall be performed within 5 business days of receipt of a request for the reading. Processing and delivery of the data will take place within the constraints listed.

Transfer Of Data To The Billing Parties Electronic

All meter usage data being provided by the MDSP which is required for billing and/or distribution service operation shall be transmitted using the applicable electronic data exchange standards.

Manual Process

The MDSP must insure that the mechanism used to transfer data, for example fax, email, or messenger service does not delay receipt of the data by the entity requiring the information for billing or settlement purposes.

Meter Transactions

The following sections detail the type of transactions that are required to be sent either manually or through some form of electronic data exchange. These transactions details include:

- Meter usage data transactions, which includes monthly data for billing, off-cycle VEE data, raw meter reads and historical usage data;
- Non-Revenue cycle data transactions which includes all physical metering information transactions (i.e., exchange of meter, request for meter test, request for unbundled electricity metering services, etc)

The timeliness and performance standards stated in this section of the document apply to all the transaction types that follow unless otherwise defined in the transaction itself.

Meter Usage Data Transactions

The following transactions are designed to communicate meter usage data between parties involved in unbundled electricity metering. These

transactions do not depend on any one particular model or method of communications. The proposed data elements for these transactions are located in Appendix 3.

It is important to note that these transactions represent the minimum set of data that must be provided to support the indicated function. Actual implementation of these transactions is beyond the scope of this document.

1. Billing VEE Cycle Data

- a. Use: To report billing cycle meter usage data that has been subjected to the VEE process to appropriate entities that require the data for billing and settlement.
- b. Responsible Entities: The MDSP issues this transaction to the appropriate parties.

2. Request for Off-Cycle Meter Usage

Off-cycle meter usage may include special read request (customer billing complaint), final read request or revalidation requests.

- a. Use: To request off-cycle meter usage that has been subjected to the VEE process.
- b. Responsible Entities: The appropriate market participant(s) using meter usage data or conducting an investigation issues this transaction.
- c. Response: The MDSP will issue a response to Off-Cycle Meter Usage Request Transaction.

3. Response to Off-Cycle Meter Usage Request

- a. Use: To report off-cycle meter usage data that has been subjected to the VEE process in response to a request.
- b. Responsible Entities: The MDSP issues this transaction to the appropriate entities.

4. Billing VEE Cycle Data Correction

- a. Use: To report corrected billing cycle meter usage data that has been subjected to the VEE process.
- b. Responsible Entities: The MDSP issues this transaction to the appropriate entities.

5. Request for Raw Meter Reading

- a. Use: To request a raw meter reading.

- b. Responsible Entities: The Utility, Energy Supplier or MDSP issues this transaction to the appropriate parties.
- c. Response: The MRSP responds with a Response to Raw Meter Reading Request.

6. Response to Raw Meter Reading Request

- a. Use: To report raw meter reading to the requesting entity.
- b. Responsible Entities: The MRSP issues this transaction to the requesting entities.

7. Request for Historical VEE Data

- a. Use: To request historical meter usage data that has been subjected to the VEE process.
- b. Responsible Entities: Energy Suppliers or MDSPs issues this transaction to the appropriate entities which should respond with historical meter usage data that has been subjected to the VEE process.
- c. Response: The Utility or MDSP will respond with a Response to Historical VEE Data Request Transaction.

8. Response to Historical VEE Data Request

- a. Use: To report historical meter usage data that has been subjected to the VEE process.
- b. Responsible Entities: The MDSP or Utility issues this transaction to the requesting entities.

Non-Revenue Cycle Data Transactions

The following transactions are designed to communicate non-revenue cycle (or control) data between parties involved in unbundled electricity metering. These transactions do not depend on any one particular model or method of communications. The list is not meant to be all inclusive, but to represent the minimum set of data that must be sent to allow control in an unbundled environment.

1. Request to Install Unbundled Electricity Metering Service

- a. Use: To initiate a transition from bundled to unbundled electricity metering services.
- b. Responsible Entities: The entity providing unbundled electricity metering services issues this transaction.
- c. Response:
 - (i) The Utility will provide a response in the form of a Customer Metering Requirements Transaction.

- (ii) If the site was already metered competitively the current MSP will supply a Site/Meter Configuration Report Transaction
- (iii) If the site is currently metered by the Utility, the Utility will provide a Site/Meter Configuration Report Transaction.

2. Request to Return to Bundled Metering Service

- a. Use: To initiate the transition of a customer from unbundled electricity metering services to bundled metering services.
- b. Responsible Entities:
 - (i) Where the customer notifies the current provider of unbundled electricity metering services, that provider generates the transaction.
 - (ii) Where the customer notifies the Utility, the Utility generates a Confirmation of Return to Bundled Metering Services Transaction and this transaction is not used.
- c. Response: The Utility issues a Confirmation of Return to Bundled Metering Service Transaction.
- d. Timing: When a customer desires to return to bundled metering services

3. Confirmation of Return to Bundled Metering Service

- a. Use: To notify the current supplier of unbundled electricity metering services of the scheduled date of commencement of bundled services.
- b. Responsible Entities: The Utility issues the transaction to the entity currently responsible for metering the site.
- c. Timing: Within 5 business days of receipt of a request for return to bundled metering services

4. Change of Meter Service Provider

- (a) Use: Notifies all authorized parties of the use of a new MSP, MRSP, or MDSP to service a customer account. Not for initiation of unbundled electricity metering services, which uses transaction (1).
- (b) Responsible Entities: The Energy Supplier generates the transaction. The Utility and any other authorized entity receives the transaction.
- (c) Timing: At least 5 business days prior to the change in MSP, MRSP, or MDSP responsibility for the account.

5. Customer Metering Requirements

- a. Uses:

- (i) To respond to a Request to Establish Unbundled Electricity Metering Services Transaction
- (ii) To notify the incoming service provider of the metering requirements based on service type and capacity and on Utility data requirements.
- b. Responsible Entities: The Utility issues the transaction. The incoming provider of unbundled electricity metering services receives the transaction.
- c. Timing: Transaction will be issued within 5 business days of receipt of a Request To Establish Unbundled Electricity Metering Service Transaction.

6. Request Current Meter/Site Configuration

- a. Use: Request to provide the latest stored data concerning the configuration of the site, which includes specific meters and transformers associated with each Service Delivery Point, any auxiliary devices installed, and the interconnections between devices.
- b. Responsible Entities:
 - (i) A incoming supplier of metering services may issue this request at onset of service
 - (ii) The current supplier of metering services or the Utility may issue this request in conjunction with an investigation
- c. Response: The current supplier of unbundled electricity metering services or the Utility if bundled service is provided will respond with a Meter/Site Configuration Report Transaction.
- d. Timing: Before the change of responsibility for unbundled electricity metering services for the site, or on the initiation of an investigation

7. Meter/Site Configuration Report

- a. Use: Provides the site or meter configuration currently recorded for the customer site. Usually in response to:
 - (i) Receipt of a Request for Meter/Site Configuration Transaction
 - (ii) A change in the configuration of the on-site metering system, such as the association or interconnection between devices
 - (iii) The change in functionality of one meter at the site
 - (iv) The change of responsibility for providing unbundled electricity metering services
 - (v) The physical creation or removal of a Service Delivery Point at the site
- b. Responsible Entities:
 - (i) The entity responsible for providing unbundled electricity metering services issues this transaction for sites where unbundled electricity metering is provided.

- (ii) The Utility issues this transaction for sites where bundled metering is provided.
- c. Timing:
 - (i) If a Request to Install Unbundled Electricity Metering Service has been filed, the existing meter service provider should file this transaction at least 5 business days before Requested Start Date.
 - (ii) Within 1 business day of meter installation or replacement, even if site or meter parameters have not changed
 - (iii) Within 5 business days of a request for the current site configuration for a site where electricity metering is unbundled.
 - (iv) Within 1 business day of the modification of the configuration of a currently installed meter.
 - (v) Depending on the complexity of the site, between 5- 15 business days from the request for the current site configuration for a site metered by the utility under bundled rates that has never been competitively metered, or any site that is not currently in the Meter/Site Configuration Database
 - (vi) Within 1 business day of the change of a MSP.

8. Service Upgrade Notification

- a. Use: To notify parties that there will be a service upgrade to a customer site.
 - (i) This could be the increase in capacity of an existing Service Delivery Point or the addition of a new Service Delivery Point.
 - (ii) The notification provides a description of the new service and the effective date that the modifications will be installed.
 - (iii) Included in this notification are the metering requirements to accommodate the new service.
- b. Responsible Entities: The Utility issues this transaction to the Energy Supplier and the entity responsible for providing unbundled electricity metering to the site.
- c. Timing: When the service to a site is to be modified by the Utility. If the service will not be available on the scheduled date, a new transaction will be generated giving the revised date.

9. Notification of Meter Installation/Replacement/Removal

- a. Use: To provide a notification to the Utility, Energy Supplier, MRSP, and MDSP that a meter has been installed, replaced or removed at an existing Service Delivery Point. If the functionality or operating parameters of the meter have changed, a Meter/Site Configuration Report Transaction will also be generated.
- b. Responsible Entities: The current MSP generates the transaction.

- c. Timing: Within 1 business day of meter installation, replacement, or removal

10. Request for Meter Removal

- a. Use: To initiate action that will result in the removal of a revenue meter from the Service Delivery Point and secure that point.
- b. Responsible Entities:
 - (i) The entity requesting the meter be removed generates the transaction.
 - (ii) A copy of this request must be sent to the entity responsible for monitoring Service Delivery Points.
- c. Response: The MSP removing the meter must produce a Notification of Meter Installation/Replacement/Removal within 1 business day of the removal.
- d. Timing: At termination of electric service or the removal of a Service Delivery Point that will be accompanied by the removal of site metering, and other instances where an Energy Supplier, MSP, MDSP, or Utility requires the removal of a meter that is the responsibility of another entity

11. Request for Meter Test

- a. Use: To request an accuracy/functionality test of a revenue meter in conjunction with an investigation, a customer complaint, or an In-Service Test Program.
- b. Responsible Entities: The transaction can be issued by the Energy Supplier, MSP, MDSP, or Utility. The transaction will be directed to the MSP for action and any other party with financial interest in the accuracy of the meter for information.
- c. Timing: At least 10 days in advance of a requested test date.

12. Report of Meter Test

- a. Use: To report the results of a test on an in-service meter
- b. Responsible Entities: The entity responsible for servicing the meter initiates the transaction. The Utility and other authorized entities must receive a copy.
- c. Timing: Within 1 business day of the completion of a test.

13. Request for Meter Reprogramming

- a. Use: To request the change in functionality or operating parameters of an on-site meter. This request may result in the replacement of an existing meter.
- b. Responsible Entities: The request should be generated by the entity requiring the change to the MSP who will actually perform the reprogramming. The Utility must receive a copy of the request to insure appropriate application of utility tariffs.
- c. Response:
 - (i) If the meter is not replaced, a Meter/Site Configuration Report Transaction must be generated by the MSP after the meter has been reprogrammed. This transaction need not specify the entire customer account, but must indicate the changes made to the individual meter.
 - (ii) If the meter is replaced, a Notification of Meter Installation/Replacement/Removal Transaction must be issued along with the Meter/Site Configuration Report Transaction described above.
- d. Timing: Whenever there is a need to initiate a modification to an on site meter.

14. Anomaly Report

- a. Use: To report any condition either found at the customer premises or discovered in the processing of metering data that is inconsistent with expected conditions or results.
- b. Responsible Entities: Any anomaly report may be generated by any market participant. The entity responsible for metering services to that customer will maintain responsibility to investigate/resolve the Anomaly.
- c. Timing: Within 1 business day of the detection of the anomaly.

15. Request for Investigation

- a. Use: To initiate an investigation in an attempt to resolve an anomaly or a customer complaint
- b. Responsible Entities: May be generated by the Utility or Energy Supplier and sent to the entity responsible for metering services.
- c. Response: The Energy Supplier/MSP/MDSP must respond with an Investigation Report Transaction on completion of the investigation.
- d. Timing: In a time frame appropriate to allow compliance with a complaint resolution process. Safety related investigations must be given priority.

16. Investigation Report

- a. Use: To report the results of an investigation
- b. Responsible Entities: All market participants can initiate the transaction. The Energy Supplier and Utility will receive the transaction as well as other involved market participant.
- c. Timing: Within 1 business day of the completion of an investigation

17. Change of Customer Account Number

- a. Use: To report change of customer account number.
- b. Responsible Entities: All involved market participants associated with that customer account number will initiate the transaction. The corresponding Energy Supplier or Utility will receive the transaction.
- c. Timing: Within one business day of the change of customer account number.

18. Notification of Termination of Service by the Utility

- a. Use: To notify all parties that the customer's service will be terminated by the Utility.
- b. Responsible Entities: The Utility generates the transaction.
- c. Timing: At or before the termination of service to a customer by the Utility but no later than one business day after termination.

19. Notification of Curtailment

- a. Use: To notify the MDSP of a curtailment by whoever issued the curtailment. This information is required by the MDSP to be able to VEE usage data for the curtailed site.
- b. Responsible Entities: Whoever issued the curtailment.
- c. Timing: This may be a notification of a curtailment relating to historical data, or to this billing period.

Validating, Editing, And Estimating (VEE) Interval Data

Introduction

This section provides guidelines for defining interval data validation, editing, and estimation techniques required to participate as an MRSP and/or MDSP.

Interval Data VEE Rules

Data validation checks are designed to identify things that can go wrong at the meter/recorder that may cause the data collected to not reflect actual usage.

These rules apply to energy and reactive interval data collected from billing meters. If data is provided for informational purposes or for analysis of the distribution system (i.e., not used for billing purposes), the requirement for validation will be subject to the requirements of the entity using the data and any applicable regulatory rules. Data that has not gone through the validation process is considered to be raw data.

MDSPs and MSPs should ensure that the meter is programmed correctly to provide the required data and that the MDSP's data processing system is set up to accurately capture and maintain information such as interval size, meter constants, and recorder channel assignments that is needed to correctly process retrieved data. The VEE processes described here do not verify that the meter is programmed correctly nor that the data processing systems contain the correct information required to process and validate the metering data.

Validation checks are usually performed by an examination of interval data using a set of criteria which predicts a range over which values are expected. Some checks may utilize status codes or errors codes originating in the meter as a criteria for acceptability. All validation checks must be performed on the meter data before that data is released as validated data. Failure of one check does not preclude the MDSP from performing other validation checks and does not necessarily indicate that the data is not usable for billing purpose.

Several words are used to describe the quality of interval data.

- Raw data - data that has not gone through the VEE process.
- Valid data - data that has gone through all required validation checks and either passed them all or has been verified.
- Verified data - data that failed at least one of the required validation checks but was determined to represent actual usage.
- Validated Data - data that has been validated and possibly edited and/or estimated (VEE) in accordance with approved procedures.

- Estimated - data that has been calculated based on standard estimation rules because the raw data was not valid or was missing.

The required validation checks assist in identifying conditions in interval kWh, kQh, kVAh, and kVARh data when these data elements are used. These checks, along with associated descriptions which provide an indication of the conditions that may be detected, appear in the following table:

Check	Conditions
Time check of meter reading device/system	<ul style="list-style-type: none"> • Time drift of meter reading device/system outside the ARA standard
Meter identification check	<ul style="list-style-type: none"> • Meter ID was reported correctly • Meter has not been replaced • Data is being reported for the correct meter
Time check of meter	<ul style="list-style-type: none"> • Time drift of meter clock outside the ARA standard
Pulse Overflow check	<ul style="list-style-type: none"> • Improper scaling factor in meter • Improperly sized instrument transformer • Hardware problem
Test Mode check	<ul style="list-style-type: none"> • Data collected when meter was in test mode that represents test load rather than actual usage
Sum check	<ul style="list-style-type: none"> • Crossed channels between meter and recorder • Pulse relay problems • Incorrect VT and CT ratios, • Incorrect meter constants
Spike check	<ul style="list-style-type: none"> • Transmission error • Spike resulting from meter test. Note that a spike can also occur after an outage - in this case the data is valid, but may or may not be used for peak billing depending on the tariff and company policy.
Reactive channel check for kWh data only if corresponding reactive channel data is available)	<ul style="list-style-type: none"> • kWh channels are correctly mapped to reactive channel • Meter is operating correctly
High/Low Usage check	<ul style="list-style-type: none"> • Dropped phases • Incorrect meter or pulse constants • Energy diversion • Fast/slow meters • Also check for the following in meter with recorder installations: erratic pulse input to recorder

Validating, Editing, and Estimating (VEE) Monthly Data

Introduction

This section defines the data validation, editing, and estimation techniques that must be applied to monthly data. Monthly data includes consumption, demand, and Time-of-Use (TOU) consumption and demand.

Required Data Validation Checks

Data validation checks for monthly data are designed to identify things that can go wrong at the meter or in the data collection process that might cause the processed usage data to not reflect actual usage. The VEE processes described here do not verify that the meter is programmed correctly nor that the data processing systems contain the correct information required to process and validate the metering data. Failure of one of these checks does not necessarily indicate that the data is not usable for billing purposes. Additionally, all checks should be performed, even if one check fails.

The following checks are required for monthly data validation for kWh and kW data. Similar checks would apply to kVARh/kQh and kVAR/kQ data if those values are required. Included in the table is an indication of the condition that the check is designed to detect.

Check	Purpose
Time check of meter reading device/system (applies to devices/systems collecting TOU data only)	<ul style="list-style-type: none">• Time drift of meter reading device/system outside the ARA standard
Time check of meter (applies to meters collecting TOU data only)	<ul style="list-style-type: none">• Time drift of meter clock outside the ARA standard
High/low usage check	<ul style="list-style-type: none">• Misread• Fast/slow meter• Broken meter• Incorrect multipliers• Energy diversion• Dropped phases

Check	Purpose
High/low demand check (applies to demand readings only)	<ul style="list-style-type: none"> • Misread • Fast/slow meter • Broken meter • Incorrect multipliers • Energy diversion • Dropped phases
Time-of-use check (applies to TOU data only)	<ul style="list-style-type: none"> • Misread • Fast/slow meter • Broken meter • Incorrect multipliers • Energy diversion • Dropped phases
Zero consumption for active meters	<ul style="list-style-type: none"> • Energy diversion • Meter doesn't register
Usage for inactive meters	<ul style="list-style-type: none"> • Unauthorized usage at a site for which there is no customer with financial responsibility
Number of dials on meter	<ul style="list-style-type: none"> • Wrong meter • Misread
Dial decimal quantity	<ul style="list-style-type: none"> • Wrong meter • Misread
Meter identification	<ul style="list-style-type: none"> • That the meter ID was reported correctly • The meter has not been changed out • The data is being reported for the correct meter

APPENDIX 1 - Demarcation Point Selection

Introduction

Site metering equipment consists of the metering circuit (current transformers, voltage transformers, test block, meter socket, and secondary wiring connecting the instrument transformers to the meter), the meter enclosure, the meter, and any auxiliary devices interfaced to the meter (such as pulse initiators, isolation relays, recorders, communication equipment, etc.). The Demarcation Point defines ownership and responsibility for each of those individual pieces of equipment that are used to meter the site.

Several states have begun unbundling metering services and established demarcation points that clearly define the scope of responsibility for the Utility and MSP. Since there are at least two models for defining this point of demarcation, this section will define the principal requirements, and also provide guidance on selecting the most appropriate demarcation point for the metering system and responsibilities of all parties associated with the site.

Ownership and Responsibility

When determining ownership and responsibility, there are two principal requirements that must be considered:

1. Protecting the general public from any conditions that could compromise safety associated with the location, selection, installation, operation, and maintenance of equipment by following sound engineering principles and operational practices.
2. Providing reliable equipment and implementing procedures to ensure that the integrity of the metering installation is not jeopardized and that accurate metering data is provided to all interested stakeholders.

Demarcation Point Selection

The Demarcation Point for metering consists of two individual points of interface:

- **Meter to Distribution System.** This Demarcation Point indicates where the Utility responsibility ends and where an MSP's responsibility begins and typically defines ownership of Current and Voltage Transformers.
- **Meter to Customer Owned Equipment.** This Demarcation Point indicates where the MSP responsibility ends and the Customer responsibility begins and is typically located at an interface between the meter and customer owned equipment such as communication networks or pulse driven devices.

The Meter to Distribution System Demarcation Point must be decided by and

clearly defined by each jurisdiction. For self-contained meters, all jurisdictions have selected the Line Side of the Test Block or Meter Socket as the Demarcation Point. Where Current and Voltage Transformers are present, individual jurisdictions have selected one of two demarcation points:

1. The following characteristics apply to situations where the demarcation point is on the Line Side of the Test Block (if present) or the Line Side of the Meter Socket (if the Test Block is not present). In this situation the Utility owns and maintains the instrument transformers.
 - Current and voltage transformers maintained by the Utility establishes a common point for all metering installations, whether self-contained or a transformer rated.
 - Utilizes a standard industry approved connection point (i.e., meter socket or test block) for demarcation. For self-contained and transformer rated installations the meter socket, when used, serves as the demarcation point. Installations that have no meter socket will use the test block (switch) as the demarcation point.
 - Allows the meter provider the flexibility of installing a given meter and adding appropriate devices (e.g. pulse devices, modems, recorders, etc.) connected to the meter without needing to take responsibility for instrument transformer control, ownership, or testing.
 - In many wiring schemes the instrument transformers are located within a distribution pad mount transformer, or on a Utility's pole or bus structure. Keeping the responsibility of the metering circuit (Current and Voltage Transformers) with the Utility should be in the best interest of the customer, Utility, and Energy Supplier due to cost, time and safety concerns with not having to make unnecessary changes when customers switch to alternate suppliers.
 - While under Utility control, Current and Voltage Transformer wiring and installation is covered under the provisions of the National Electric Safety Code (NESC). Transferring control to another entity may result in a requirement to comply with the provisions of the National Electric Code (NEC), which may not be met by existing installations.
 - Clearly defines and provides a measurable method (voltage/current at test block) of determining responsibilities on metering related problems.
2. The following characteristics apply to those situations where the demarcation point is located before the Current and Voltage Transformers. In this situation the Utility does not own or maintain the instrument transformers.

- Current and voltage transformers maintained by MSP.
- All site meter equipment can be unbundled.
- If the entire metering system is owned by the same entity, then the responsibility for metering accuracy and reliability rest on that entity as opposed to sharing the responsibility between the owner of the meter circuit (Current and Voltage Transformers) and the owner of the meter.

The two options listed above provide guidance for unbundling the metering system. Case 1 unbundles only the meter while 2 unbundles the entire metering system. In either case, the responsibilities of all parties must be clearly defined. The difference in these approaches is reflected in the ownership and/or responsibility for Current and Voltage Transformers. No attempt is made here to determine which approach is preferred, rather, some insight is offered to assist individual jurisdictions that have not yet made this decision.

Appendix 2: Reframing Usage Data

Introduction

Reframing refers to providing data for a corrected time period, usually when a customer's start-up or turn-off occurs. When data is "reframed", all affected months must be resent and flagged as adjusted. This Appendix provides example scenarios that illustrate how data may be reframed using anticipated situations.

Note: The use of the terms sent, send, resend, or resent indicate the process of making the data available without implying a specific mechanism to do so.

Scenario #1

(Start date specified, data sent, start date changed to a later date, before read date).

1. The MDSP is contacted and told that service for a given customer and meter is starting at a given date/time.
2. The MDSP obtains the start meter read.
3. On the meter's scheduled read date, the MRSP reads the meter. The MRSP forwards the interval data to the MDSP. The MDSP sends the interval data for the meter from the start date/time through the scheduled read date.
4. The MDSP is notified that the customer actually moved in later than originally specified.
5. The MDSP resends the customer's interval data that is flagged as adjusted data; the data now goes from the new (later) start date to the scheduled read date. This is to be performed only if required by the ARA.

April 28	MDSP notified of new service starting 5/1
May 1 - Original Start Date	MRSP starts reading interval data
May 3 – New Start Date	
May 5 – Scheduled Meter Read	MDSP sends interval data for 5/1 - 5/4
May 7	MDSP notified service actually started 5/3
May 9	MDSP resends interval data for 5/3 - 5/4 is flagged as adjusted data.

Scenario #2

(Start date specified, data sent, start date changed to a date after the read date).

1. The MDSP is contacted and told that service for a given customer and meter is starting at a given date/time.
2. The MDSP obtains the start meter read.
3. On the meter's scheduled read date, the MRSP reads the meter. The MRSP forwards the interval data to the MDSP. The MDSP sends the interval data for the meter from the start date/time through the scheduled read date.
4. The MDSP is notified that the customer actually moved in later than originally specified - later than the read date of the data just sent. That is, the data just sent is completely invalid for the customer.
5. The MDSP sends data starting on 5/7 as if it were original data. This is to be performed only if required by the ARA.

April 28	MDSP notified of new service starting 5/1
May 1 – Original Start Date	MRSP starts reading interval data
May 5 – Scheduled Meter Read	MDSP sends interval data for 5/1 - 5/4
May 7 – New Start Date	
May 8	MDSP notified service actually started 5/7
May 10	MDSP sends interval data for period starting 5/7

Scenario #3

(Start date specified, data sent, start date changed to an earlier date).

1. The MDSP is contacted and told that service for a given customer and meter is starting at a given date/time.
2. The MDSP obtains the start meter read.
3. On the meter's scheduled read date, the MRSP reads the meter. The MRSP forwards the interval data to the MDSP. The MDSP sends the interval data for the meter from the start date/time through the scheduled read date.
4. The MDSP is notified that the customer actually moved in earlier than originally specified.
5. If the MDSP has interval data for the new period (from the new start date), the MDSP resends the data from the new start date to the read date and flags it as adjusted data. Note that this may include more than one billing period of data. If interval data is not available for the earlier time, the MDSP estimates the data and resends it in a similar fashion. In

this case, the estimated intervals are marked as estimated. This is to be performed only if required by the ARA.

April 28	MDSP notified of new service starting 5/3
May 1 - New Start Date	
May 3 – Original Start Date	MRSP starts reading interval data
May 5 – Scheduled Meter Read	MDSP sends interval data for 5/3 - 5/4
May 8	MDSP notified service actually started 5/1
May 10	MDSP resends data from 5/1 - 5/4 and flags it as adjusted data

Scenario #4

(Stop date specified, data sent, stop date changed to a later date).

1. The MDSP is contacted and told that service for a given customer and meter is ending at a given date/time.
2. The MDSP obtains the stop meter read.
3. The MDSP sends the meter’s data from its last read schedule through the stop read.
4. The MDSP is notified that the customer actually moved out later than originally specified.
5. If possible, the MDSP obtains interval data for the additional time period the customer occupied the premise. If not, the MDSP estimates the data. The MDSP resends the data from the meter’s last scheduled read day through the new stop date/time and flags as adjusted. Note that this may include more than one billing cycle, depending on when the MDSP is notified of the change in stop dates. This is to be performed only if required by the ARA.

April 28	MDSP notified service ending 5/1
May 1 – Original Stop Date	MDSP obtains final meter read
May 2	MDSP sends final data through 5/1
May 5 - New Stop Date	
May 8	MDSP notified service actually stopped 5/5
May 10	MDSP obtains or estimates data through 5/5 and resends data through 5/5 and flags as adjusted.

Scenario #5

(Stop date specified, data sent, stop date changed to an earlier date after meter’s scheduled read date).

1. The MDSP is contacted and told that service for a given customer and meter is ending at a given date/time.
2. The MDSP obtains the stop meter read.
3. The MDSP sends the meter's data from its last read schedule through the stop read.
4. The MDSP is notified that the customer actually moved out earlier than originally specified.
5. The MDSP resends the meter's data from its last scheduled read date through the new stop date/time and flags as adjusted. This is to be performed only if required by the ARA.

April 28	MDSP notified service ending 5/3
May 1 – New Stop Date	
May 3 - Original Stop Date	MDSP obtains final meter read
May 4	MDSP sends final data through 5/3
May 8	MDSP notified service actually stopped 5/1
May 10	MDSP resends data through 5/1 and flags as adjusted.

Scenario #6

(Stop date specified, data sent, stop date changed to an earlier date before the previous read date).

1. The MDSP is contacted and told that service for a given customer and meter is ending at a given date/time.
2. The MDSP obtains the stop meter read.
3. The MDSP sends the meter's data from its last read schedule through the stop read.
4. The MDSP is notified that the customer actually moved out earlier than originally specified. The new date is prior to the last scheduled read date previously sent - i.e. none of the data in the last file sent is valid for this customer.
5. The MDSP resends the meter's data from the previous scheduled read date that is before the new end date through the new end date and flags as adjusted. This is to be performed only if required by the ARA.

April 28	MDSP notified service ending 5/5
May 1 – Scheduled Read Date	MDSP reads and sends interval data through 4/30
May 5 - Original Stop Date	MDSP obtains final meter read
May 6	MDSP sends final data through 5/5
May 8	MDSP notified service actually stopped 4/29
May 10	MDSP resends data through 4/29 and flags as adjusted

Appendix 3 – Meter Usage Data Elements

Meter Usage Data and Meter Reading Data Elements

The following represents the minimum set of data elements that may be necessary to report meter usage data and/or meter reading data. Before implementation, additional work will be needed to define the appropriate fields for each transaction as well as the format of the data contained in those fields. The transaction is defined using the Transaction Identifier, Purpose Identifier, Report Identifier and Action Identifier.

Name	Type	Description
Transaction Set Identifier	Alphanumeric	Unique identifier of a transaction (meter usage, meter read etc.)
Purpose Identifier	Alphanumeric	Identifies if reading is original reading or result of an adjustment
System Date	Date	Date transaction is processed
Report Type Identifier	Alphanumeric	Identifies contents of document (interval of cumulative).
Action Identifier	Alphanumeric	Indicates purpose of transaction (monthly data, final read data, special read request, revalidation)
Receiver Name	Alphanumeric	Identification of entity receiving data
Sender Name	Alphanumeric	Identification of entity sending data
Customer Name	Alphanumeric	Name of end use customer
Utility Account Number	Alphanumeric	Utility account number identification
*****	Physical Meter Information	*****
SPD ID	Alphanumeric	Unique identifier of the meter service point

Service Period Begin Date/Time	Date/Time	Start date and time of the period for which the readings are provided. For interval data, this is the beginning of the first interval.
Service Period End Date/Time	Date/Time	End date and time of the period for which the readings are provided. For interval data, this is the end of the last interval.
Meter Change Out Date/Time	Date/Time	Used in conjunction with either the Service Period Start Date or the Service Period End Date to indicate when a meter has been replaced
Meter Number	Alphanumeric	Unique meter identification of this specific meter
Meter Role	Alphanumeric	Effect of meter usage data on account total (additive, subtractive, prime)
Number of Dials	Numeric	Identifies number of meter dials displayed on the meter
Quantity Qualifier	Alphanumeric	Represents whether the quantity is actual or estimated
Quantity Delivered	Numeric	Represents the quantity of consumption delivered for a service period.
Quantity Delivered Unit of Measurement	Alphanumeric	Indicates unit of measurement for quantity of consumption delivered during service period (kWH, kW, kVAR)
Interval Date	Date/Time	Start date and time of the period for which the readings are provided. This is the end of the first interval.
Measurement Significance	Alphanumeric	Identifier used to qualify, or further define a measurement

Identifier		value. (On-peak, Off-peak, Totalized)
Meter Multiplier	Numeric	Meter Constant – used to represent how many units are reflected by one dial or digit change
Power Factor	Numeric	Relationship between watts and volt-amperes necessary to supply electric load
Transformer Loss Multiplier	Numeric	When a customer owns a transformer and the transformer loss is not measured by the meter

Request for Meter Usage Data and/or Meter Reading

The following represents the minimum requirements of data elements necessary to request meter usage data and/or meter reading data. The transaction is defined using the Transaction Identifier, and Action Identifier.

Name	Type	Description
Transaction Set Identifier	Alphanumeric	Unique identifier of a transaction (meter usage, meter read etc.)
System Date	Date	Date transaction is processed
Action Identifier	Alphanumeric	Indicates purpose of transaction (monthly data, final read data, special read request, revalidation)
Receiver Name	Alphanumeric	Identification of entity receiving request
Sender Name	Alphanumeric	Identification of entity sending request
Utility Account Number	Alphanumeric	Utility account number identification

Physical Meter Information

SPD ID	Alphanumeric	Unique identifier of the meter service point
Service Period Begin Date/Time	Date/Time	Start date and time of the period for which the readings are provided. For interval data, this is the beginning of the first interval.
Service Period End Date/Time	Date/Time	End date and time of the period for which the readings are provided. For interval data, this is the end of the last interval.
Meter Number	Alphanumeric	Unique meter identification of this specific meter

Appendix 4 - Non-Revenue Cycle Data Elements

Introduction

The following list of data elements associated with the transfer of non-revenue cycle data are included as a minimum set of elements needed to support one business model. The actual elements required to support a specific model may include additional elements, or exclude elements listed that may not be available. This list is not meant to replace the transactions that have been developed under various EDI initiatives, but to supplement those initiatives and provide a higher level overview of what data must be transmitted without the added burden of defining the format for such transfers.

Request to Install Unbundled Electricity Metering Service

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Customer Name	Alphanumeric	Name of Customer
Customer Address	Alphanumeric	Street and city address of the Customer
Service Delivery Point List	List	List of all unique Service Delivery Points affected by this request.
Customer Contact	Alphanumeric	Name of the Customer contact approving the request
Customer Phone	Alphanumeric	Phone of the Customer contact approving the request
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier issuing the transaction
Energy Supplier Contact	Alphanumeric	Name of Energy Supplier representative submitting the transaction
Energy Supplier Phone	Alphanumeric	Phone number of Energy Supplier contact
MSP ID	Alphanumeric	Unique Identification of the MSP
MRSP ID	Alphanumeric	Unique identification of the MRSP
MDSP ID	Alphanumeric	Unique Identification of the MDSP
Requested Start Date	Date	Requested date for start of supply of unbundled metering

Request to Return to Bundled Metering Service

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Service Delivery Point List	List	List of all unique Service Delivery Points affected by this request.
Service Provider ID	Alphanumeric	Unique identification of service provider requesting the return to bundled service
Reason	Note Field	Reason for return to Utility metering services
Disposition of Metering	Note Field	How will the currently installed meters be treated? Left in place, removed, sold to Utility, etc.
Requested Return Date	Date	Requested date for return of metering to Utility

Confirmation of Return to Bundled Metering Service

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the customer
Utility ID	Alphanumeric	Identification of the Utility generating this transaction
Service Delivery Point List	List	List of all unique Service Delivery Points affected.
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier
Return Date	Date	Scheduled date for return to bundled metering service

Change of Meter Service Provider

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier issuing this transaction
Effective Date	Date	Effective date that the new service provider will take over the account
New MSP ID	Alphanumeric	Unique identification of the new MSP
New MDSP ID	Alphanumeric	Unique identification of the new MDSP
Old MSP ID	Alphanumeric	Unique identification of the old MSP
Old MDSP ID	Alphanumeric	Unique identification of the old MDSP

Customer Metering Requirements

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Utility ID	Alphanumeric	Identification of the Utility generating this transaction
Service Delivery Point List	List	List of all unique Service Delivery Points included in the requirements
Start Date	Date	Scheduled date at which Unbundled Metering will begin
Locking Requirements	Boolean	Must meters at this site be locked?

For each Service Delivery Point in the List, the following must be provided:

Meter Form	Alphanumeric	The meter form required to monitor the Service Delivery Point
Meter Capacity	Alphanumeric	Current and Voltage rating of meter required to monitor the Service Delivery Point
Service Voltage	Alphanumeric	Voltage supplied to the Customer at this Service Delivery Point
CT Definition	Alphanumeric	Current Transformer ratio requirements
VT Definition	Alphanumeric	Voltage Transformer ratio requirements
Profile	Note Field	Profile requirements B interval length, channel assignments, units of measure, aggregation with other Service Delivery Points, etc.
Demand	Note Field	Demand requirements B interval length, sub-intervals, concurrent with other Service Delivery Points, etc.
Reactive	Note Field	Reactive Measurement requirements
Compensation	Note Field	Transformer and Line Loss Compensation values for this Service Delivery Point
Rating Periods	Note Field	If not 24 hrs, 7 days, specify.
Cycle Requirements	List	List of dates on which the data must be received for Utility billing

Request Current Meter/Site Configuration

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Service Delivery Point ID	Alphanumeric	Unique identification of Service Delivery Point (if not provided, the configuration of all Service Delivery Points associated with the Customer ID will be requested)
Issuing Party	Alphanumeric	Identification of the entity requesting the report

Meter/Site Configuration Report

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of Customer
Issuing Party	Alphanumeric	Identification of the entity generating this transaction
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier servicing the account (if competitively metered)
Utility ID	Alphanumeric	Unique identification of utility servicing the account (if bundled metering)
Service Delivery Point List	List	List of all service delivery points associated with the Customer account (Only provided when the entire Customer account configuration is requested)
For each Service Delivery Point ID in the list, the following must be provided:		
Service Delivery Point ID	Alphanumeric	Unique identification of the Service Delivery Point

Name	Type	Description
Meter ID	Alphanumeric	Unique identification of meter
Meter Manufacturer	Offset to a List of Manufacturers	Unique identification of the meter manufacturer
Meter Model	Offset to a list of models	Uniquely identifies the manufacturer's model id
Meter Form	Offset to a list of forms	Electrical form factor of the meter
Meter Constant	Floating Point	Multiplier that must be applied to meter readings
Socket	Boolean	Socket or A Base Meter
Locked	Boolean	Locked or Unlocked
CT Ratio	Numeric	Ratio of Current Transformer
PT Ratio	Numeric	Ratio of Potential Transformer
Units of Measure	List	KWH, KVARH, KVAH, etc. that are recorded by the meter
Pulse Constant	Numeric	Value of a pulse in WH
Transformer Loss Compensation	Numeric	Energy loss in the transformer at rated voltage (Iron loss)
Line Loss Compensation	Numeric	Energy Loss in the feeder at specified current (Copper loss)
Line Loss Specified Current	Numeric	Current at which the energy loss in the line is reported
Profile	Numeric	Number of profile channels
Profile channel assignments	List	Profile parameters B interval length, channel assignments, units of measure, aggregation with other Service Delivery Points, etc.
Demand	Boolean	Is demand measured?

Name	Type	Description
Demand Interval	Numeric	Demand interval in minutes
Demand Sub-Intervals	Numeric	Number of subintervals used in demand calculations
Interval size	Numeric	Number of minutes per interval for profile
Communication type	Offset to a list of communication types	Phone, RF, PLC, etc.
Receiving Devices	List	List of unique identifications for devices receiving data or pulses from this device.
Source Devices	List	List of unique identifications for devices providing data or pulses to this device

Service Upgrade Notification

Name	Type	Description
Service Delivery Point ID	Alphanumeric	Unique identification of service delivery point
Utility ID	Alphanumeric	Unique identification of utility
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier
Customer ID	Alphanumeric	Unique identification of customer
Reference ID	Alphanumeric	Unique ID associated with this notification of impending change
Change Type	Note field	Description of the change
Meter Modification Requirement	Note field	Description of the meter modifications needed to support the change
Scheduled Date	Date	Date of Service Modification
Revised Date	Date	Used to modify the scheduled date

Notification of Meter Installation/Replacement/Removal

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of Customer
Service Delivery Point ID	Alphanumeric	Unique identification of service delivery point affected
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier performing the action
MSP ID	Alphanumeric	Unique identification of MSP performing the action
Effective Date	Date	Date of Installation, Replacement, or Removal
Installed Meter ID	Alphanumeric	Unique identification of meter installed at the Service Delivery Point (if any)
Removed Meter ID	Alphanumeric	Unique identification of meter removed from the Service Delivery Point (if any)
Removed Meter Cumulative Reading	Numeric	Consumption Reading from the meter removed (if any)
Removed Meter Demand Reading	Numeric	Demand reading from meter removed (if any)
Reason	Note field	Description of reason for the replacement or removal (if performed)
Disposition of Removed meter	Note field	What was done with the old meter (if any)
Disposition of Site	Note Field	What was done to secure the site after removal of the meter (if performed)

Request for Meter Removal

Name	Type	Description
Service Delivery Point ID	Alphanumeric	Unique identification of Service Delivery Point
Meter ID	Alphanumeric	Unique identification of meter
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier
Removal Reason	Note Field	Reason for the removal of the meter
Requested Removal Date	Date	Date of Requested Removal

Request for Meter Test

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Service Delivery Point ID	Alphanumeric	Unique identification of the service delivery point
Meter ID	Alphanumeric	Unique identification of meter
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier responsible for metering the Customer
Test Reason	Note Field	Reason for performing the test
Requested Test Date	Date	Requested Date for Test
Coordination	Note Field	Do other parties need to be present for the test?

Report of Meter Test

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Service Delivery Point ID	Alphanumeric	Unique identification of Service Delivery Point
Meter ID	Alphanumeric	Unique identification of meter
Energy Supplier ID	Alphanumeric	Unique identification of the responsible Energy Supplier
MSP ID	Alphanumeric	Unique identification of MSP performing the test
Test Date	Date	Date of Test
Tests Performed	List	Listing of all tests performed
Witnesses	List	List of all witnesses present for test
As Found and As Left Test Results	Note Field	Complete results of the test i.e. accuracy under various loads, balance, meter functionality check, etc.
Work Performed	Note Field	Was meter adjusted, modified, or replaced to gain acceptable results
Test Conditions	Note Field	Any unusual conditions noted during test i.e. weather, site condition, line voltages, etc.

Request for Meter Reprogramming

Name	Type	Description
Service Delivery Point ID	Alphanumeric	Unique identification of Service Delivery Point
Meter ID	Alphanumeric	Unique identification of meter
Energy Supplier ID	Alphanumeric	Unique identification of the Energy Supplier

Required Date	Date	Date that the reprogramming must take place
Reason to reprogram	Note Field	Reason that the meter must be reprogrammed
Requested Changes	List	Listing of all changes that are to be made to the meter

Anomaly Report

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer (where known)
Service Delivery Point ID	Alphanumeric	Unique identification of Service Delivery Point
Meter ID	Alphanumeric	Unique identification of meter
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier
Date Detected	Date	Date that the Anomaly was first detected
Reporting Entity	Alphanumeric	Identification of the entity reporting the anomaly
Safety Related	Boolean	Used to highlight an anomaly as safety related
Anomaly Description	Note Field	Description of the anomaly

Request for Investigation

Name	Type	Description
Service Delivery Point ID	Alphanumeric	Unique identification of Service Delivery Point
Customer ID	Alphanumeric	Unique identification of the customer
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier
Reason	Note Field	Reason for performing the investigation
Associated Meters	List	List of all meters associated with the site

Investigation Report

Name	Type	Description
Site ID	Alphanumeric	Unique identification of site
Customer ID	Alphanumeric	Unique identification of the Customer
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier performing the investigation
Associated Meters	List	List of all meters associated with the site
Investigation Result	Note Field	Results of the investigation
Action Taken	Note Field	What actions have already been taken to resolve the issues that caused the investigation
Modified Readings	Note Field	Any readings of Customer meters that have been modified as a result of the investigation
Resolution Requirements	Note Field	What actions are needed to resolve problems found in an investigation
Resolution Date	Date	Expected date of final resolution of issues found in an investigation

Notification of Termination of Service by the Utility

Name	Type	Description
Customer ID	Alphanumeric	Unique identification of the Customer
Energy Supplier ID	Alphanumeric	Unique identification of Energy Supplier
Reason	Note Field	Reason for terminating service
Associated Service Delivery Points	List	List of all Service Delivery Points affected
Associated Meters	List	List of all meters affected

Appendix 5 – Interval Data Validating, Editing, and Estimating Rules

Interval data collection and validation rules

Some checks must be done as the data is read from the meter; some checks can be done anytime between when the data is collected from the meter and the end of the cycle, and the other checks can only be done on a billing period basis at the end of the billing cycle. They are broken out that way in this description.

- 1.1. Time check of meter reading device/system ensures that the collection device is synchronized to the national time standard before data collection begins.
- 1.2. Collect Data
- 1.3. As Data is Collected
 - 1.3.1. Check Meter Identification – verify that the meter’s identification matches what is expected.

- 1.3.2. Perform Time Tolerance Check on Meter and Data.

The time tolerance check is performed to minimize and correct meter clock drift and to minimize and correct the data problems associated with meter clock drift.

To perform a time tolerance check on the meter, compare meter time to data collection device time. Note that depending on the communication technology used, network latency must be taken into account.

Pass/Fail Criteria

- If meter time is within 3 minutes of time standard, the meter passes the time tolerance check. (Note that if the meter time is within the 3-minute tolerance, the meter time can optionally be corrected.)
- If meter time is off by more than 3 minutes, the meter time must be corrected. If the meter fails the time tolerance check for three consecutive reads, the meter must be physically inspected/tested.

To perform a time tolerance check on the data, compare the number of intervals retrieved from the meter to the number of intervals expected given the elapsed time.

Pass/Fail Criteria

- If the actual number of intervals is equal to the expected number, the data passes the time tolerance check.
- If the actual number of intervals differs from the expected number, the data fails the time tolerance check. The data to be corrected includes all intervals from the last time the meter time was determined to be good (i.e., within the 3-minute tolerance) and when it was discovered that the meter time was off by more than 3 minutes and the meter time was reset.

If data fails the Time Tolerance Check

1. If the meter time was off by less than or equal to 55 minutes and the time deviation was assumed to be linear drift, prorate the data using one of the algorithms in
2. If the meter time was off by more than 55 minutes or the time deviation is non-linear the data must be estimated

1.4. Either as Data is Collected or Prior to Publishing on MDSP Server

1.4.1. Perform Pulse Overflow Check

Inspect each interval for this condition. If a pulse overflow occurs, the meter requires physical meter test/maintenance. Intervals with pulse overflows must be estimated.

1.4.2. Perform Test Mode Check

If the MDSP determines the meter was in test mode, the MDSP must ensure that the customer is not billed for the test load. If no actual customer usage data is available for the time in which the meter was in test mode, zero usage is reported for that period; this data is valid. If the meter is inadvertently left in test mode, the data must be estimated if actual usage data is not available from the meter.

1.4.3. Perform Sum Check

The sum check is performed to ensure that the difference between the energy use recorded in the intervals and the energy use recorded in the meter over the same time period is within an acceptable range. This check may be done on either consumption or pulse data, provided the data scaling is consistent throughout the period.

How to do the Sum Check

1. Calculate the energy use recorded in the intervals by summing the intervals between the start and stop meter readings.

2. Calculate the energy use recorded by the meter by taking the difference between the start and stop readings accounting for possible rollover between start and stop readings. For example, if the start reading was 99968 and the stop reading was 00294, and the meter reading rolls over at 99999, the difference would be 326.
3. Compare the energy use recorded in the intervals to the energy use recorded by the meter. Note that the values must be in the same units for the comparison.

Pass/Fail Criteria

- If difference is \leq two meter multipliers, the data passes the sum check.
- If difference is $>$ two meter multipliers, the data fails the sum check.

If data fails the Sum Check

1. Several optional steps may be taken to resolve the sum check failure.
 - a. Reread the meter and redo the sum check from original start meter reading to new stop meter reading.
 - b. Redo the sum check, taking into account the differences between the time of the start read and the start of the first interval, and the time of the stop read and the end of the last interval.
 - c. Redo the sum check, taking into account missing or incomplete intervals.
 - d. Additional checks may be performed, based on the technology used, to verify that the interval data is an accurate representation of usage as measured by the meter readings.
2. If sum check is not resolved, perform manual inspection of data.
 - a. Verify meter and pulse multipliers. If a multiplier was incorrect, redo the sum check using the correct multipliers.
 - b. Check for a meter change between the start and stop meter readings. If the meter was changed, redo the sum check for each meter independently.

- c. Manually inspect data. If the data seems reasonable, it can be considered verified.
 - d. If the data does not seem reasonable, perform physical meter test/inspection. If meter tests OK, the data can be considered verified. If a problem is found with the meter, the data must be estimated. (Note: if the problem existed prior to this billing period, previously posted data must be adjusted and re-posted.) If unable to visit site and perform meter test prior to posting the data, the data must be estimated.
 - e. If interval data is available but meter readings are not available, manually inspect the data. Data that seems reasonable (compared with historical data) can be considered verified. Any data that does not seem reasonable must be estimated.
3. If the sum check failure cannot be resolved, the data must be estimated.

1.4.4. Perform Spike Check

The spike check is performed to identify intervals with suspiciously high usage relative to the surrounding intervals. This check may be done on either consumption or pulse data, provided that data scaling is consistent throughout the period.

How to do the Spike Check

1. For each 24-hour period, identify the highest and third highest peaks. (Normally the 24-hour period is from midnight to midnight. If the data is at the beginning of the span and doesn't start at midnight, use enough data from the next day of data to get 24 hours of data. If the data is at the end of the span and doesn't stop at midnight, use enough data from the next to last day of data to get 24 hours.)
2. If the highest peak is less than or equal to the spike check threshold of 10 pulses, skip the spike check. (A spike check threshold is used to eliminate false spikes for meters with very low usage.)
3. If the highest peak is greater than the spike check threshold of 10 pulses, subtract the third highest peak from the highest peak and divide by the third highest peak.

Pass/Fail Criteria

- If $((\text{highest peak} - \text{third highest peak}) / \text{third highest peak}) \leq 1.8$, the interval passes the spike check.
- If $((\text{highest peak} - \text{third highest peak}) / \text{third highest peak}) > 1.8$, the interval fails the spike check.

If data fails the Spike Check

1. Optionally reread the meter. If you get different value from reread, redo spike check.
 2. If value is the same on reread or you cannot reread the meter, perform manual inspection of data.
 - a. Look for similar patterns on similar days. If a similar pattern is found and this seems reasonable, the data can be considered verified.
 - b. Optionally check with customer for unusual conditions at the time of the spike. If a legitimate reason for spike is found, the data can be considered verified.
 3. If no similar pattern or legitimate reason for spike is found, the interval with the spike must be estimated.
 4. If there is a regular pattern of failing this check, the customer may be an irregular usage customer. See section 1.8 on Irregular Usage Customers for additional information.
- 1.4.5. If Reactive Interval Data is Available, Perform the Reactive Channel Check

The reactive channel check is performed to identify intervals where reactive load (kVARh/kQh,etc) is present and active load (kWh) is not, indicating a suspicious usage pattern and possible meter malfunction. This check is only required when both kWh and reactive metered values are used for billing. If reactive data is available but not used for billing, the check is optional. This check may be done on either consumption or pulse data, provided the data scaling is consistent throughout the period.

How to do the Reactive Check

1. If multiple kWh channels map to a single reactive channel, or multiple reactive channels map to single kWh channel, the appropriate channels must be totaled prior to this check.
2. If there are any kWh intervals with zero consumption, check the corresponding reactive interval.

Pass/Fail Criteria

- If the corresponding reactive interval is also zero or less than or equal to the reactive check threshold of 4 pulses, the kWh data passes the reactive check. (A reactive check threshold is used to eliminate false errors for meters with very low usage.)
- If the corresponding reactive interval is greater than the reactive check threshold of 4 pulses, the kWh interval fails the reactive check.

If data fails the Reactive Check

1. Several optional steps may be taken to resolve the reactive check failure.
 - a. Investigate to determine if this data represents actual customer usage, in which case the data can be considered verified.
 - b. If multiple kWh channels map to a single reactive channel, investigate to determine if the problem can be directly traced to specific kWh channels. If this is the case, only data for those channels must be estimated. If the problem is not attributable to specific channels, all kWh channels need to be estimated.
2. If no legitimate reason for the reactive check failure is found, the intervals with failures must be estimated.
3. If there is a regular pattern of failing this check, the customer may be an irregular usage customer. See section on Irregular Usage Customers for additional information.

1.5. On the Billing Cycle for the Meter

1.5.1. High/Low Usage Check

This test must be performed on the data that has passed or been verified for previous checks, with no estimated values included. This identifies metered usage that is suspiciously high or low relative to historical usage. It may optionally also be performed on all data (valid and estimated) to provide a reasonableness check on the estimates derived using the standard estimation techniques.

This check must be done on consumption data, not pulses.

How to do the High/Low Usage Check

1. If last year's data is available, calculate average daily usage for same billing month last year; use summed VEE or historical

- billing interval data if available, if not use VEE or historical billing usage (i.e., difference between register readings).
2. If last year's data is not available, calculate average daily usage for the previous billing month; use summed VEE or historical billing interval data if available, if not use VEE or historical billing usage (i.e., difference between register readings).
 3. If last year's data and last month's data are not available, skip the high/low usage check.
 4. Calculate average daily usage for this billing month using either summed VEE data (if check includes estimated data) or sum of all intervals not requiring estimation (if check does not include estimated data). If not all intervals are included in the sum, prorate the sum accordingly.

Pass/Fail Criteria

- If $|(\text{historical daily average} - \text{this month's daily average})| \leq 0.25 \times \text{historical daily average}$, the data passes the high/low usage check.
- If $| (\text{historical daily average} - \text{this month's daily average}) | > 0.25 \times \text{historical daily average}$, all data in the billing month fails the high/low usage check.

If data fails the High/Low Usage Check

1. Perform manual inspection of data.
 - a. Look at recent history for the meter. If monthly usage has been on a trend in the appropriate direction and this seems reasonable, the data can be verified.
 - b. Optionally check with customer for changed usage patterns. If changed usage patterns match change in data, the data can be verified.
 - c. Check to see if some of the data looks reasonable; reasonable looking data can be verified. For example, if a meter fails sometime during the month, the data at the beginning of the month may be OK, while the data after the meter failure may be obviously bad.
 - d. If the data does not seem reasonable, perform physical meter test/inspection. If meter tests OK, the data can be verified. If a problem is found with the meter, the data must be estimated. (Note: if the problem existed prior to this billing period, previously posted data must be adjusted and re-posted.) If unable to visit site and perform meter test prior to posting the data, the data must be estimated.

2. If the data is investigated and found to be accurate, the data is verified.
 3. If the data fails high/low usage check, suspect data must be estimated.
 4. If there is a regular pattern of failing this check, the customer may be an irregular usage customer. See section 1.8 on Irregular Usage Customers for additional information.
- 1.6. After all validation checks have been performed and required data has been estimated, rerun validation checks to ensure reasonableness of estimates.
- 1.7. Record Keeping Requirements
If data failed one or more validation checks, the specific checks that the data failed must be recorded on an interval level, and:
1. If the data was manually verified, that information must be recorded on an interval level. Verified data is valid.
 2. If the validation failure(s) were not resolved through accepted methods, the data must be estimated.

For each interval that is estimated, the MDSP must record the estimation algorithm used. Interval data estimation algorithms include:

- less than 2 hours
- greater than 2 hours – not scaled based on usage
- greater than 2 hours – scaled based on usage
- time-drifted intervals prorated
- intervals adjusted
- intervals manually estimated
- intervals estimated due to meter interval programmed incorrectly
- load profile template used

1.8. Irregular Usage Customers

An irregular usage customer is one whose usage pattern does not follow normal usage patterns and consistently fails the spike check, reactive check, or high/low usage check. An MDSP can identify a customer as an irregular usage customer if:

1. the customer data fails the standard validation check for three consecutive months and the MDSP verifies that the data represents the actual customer usage, OR
2. MDSP is notified by the customer's Energy Supplier or previous MDSP of the irregular usage pattern.

The data used to identify an irregular usage customer could be data collected by the MDSP, or historical data provided by the previous Energy Supplies or MDSP. An MDSP may modify the spike check and/or high/low usage check, and skip the reactive check if an irregular usage customer consistently fails the check. The MDSP must notify both the customer's Energy Supplier and Utility of the customer's irregular usage status and what modified checks will be performed.

The goal of the modified checks is to automate the manual procedures the MDSP would perform to verify that this is the customer's normal usage pattern. An MDSP may use a variation of the spike check or high/low usage check based on the actual usage pattern. Note that the MDSP may not skip the spike check or high/low usage check. If the data passes the modified check, the data is valid and does not need to be marked as verified.

- Examples of modifications for the spike check include modifying the spike check value (180%) or the pulse threshold value (10 pulses).
- Examples of modifications for the high/low usage check include changing the percentages (+/- 50%), using the year's average instead of one billing period's average, or comparing to the minimum and maximum values for the past year.

For some customers, irregular usage patterns are symptomatic of the business and will always be present, such as co-generation customers. For other customers, irregular usage patterns may be a temporary condition, such as when a factory adds a second shift and fails the high/low usage check for the first 12 months. The MDSP must determine whether a customer is a permanent or temporary irregular usage customer. Temporary irregular usage customers must be reviewed annually to determine if they are still irregular usage customers or should be returned to the normal checks.

Interval Data Estimation Rules

Estimate intervals needing estimation using the following estimation rules

- 2.1. If section of data needing estimation is 2 hours or less in length, use point-to-point linear interpolation to estimate the data. Intervals containing a power failure cannot be used as end points for interpolation.

How to apply Point-to-Point Linear Interpolation

1. If the section occurs in the middle of the data, the "first point" is the last valid interval before the section, and the "second point" is the first valid interval after the section.

2. If the section occurs at the beginning of the span, use the last interval from the historical data as the first point if the historical data is available and valid. Otherwise, use the second point (the first valid interval after the section) as the first point – this will cause the load to be estimated as a flat load.
 3. If the section occurs at the end of the span, use the first point (the last valid interval before the section) as the second point – this will cause the load to be estimated as a flat load.
- 2.2. If the section of data needing estimation is more than 2 contiguous hours, use the average of selected reference days to estimate the data.

Rules and definitions for selecting reference days for estimation:

- “Same weekdays” are defined as the same day of week as the day that needs estimation. In the case of holidays, “same weekdays” are holidays.
- “Like days” are defined as the same day type (i.e., weekday, weekend, and perhaps holidays) as the day that needs estimation.
- A standard list of holidays should be used, regardless of the tariff or service territory of the meter. The “legal” definitions of the holiday is used; if the holiday falls on a Sunday, the “legal” holiday is the following Monday. Otherwise the “legal” holiday is the same date as the actual holiday. Additional holidays may be recognized by the Utility or the ARA. The holidays used are the following:
 - New Years Day
 - Presidents Day
 - Memorial Day
 - Independence Day
 - Labor Day
 - Veterans Day
 - Thanksgiving Day
 - Christmas Day
- Only “valid” intervals can be used for estimation. Valid intervals are defined as those that have passed all validation checks or have been verified. Estimated intervals cannot be used for estimation.
- Data from days with a power failure cannot be used for estimation. Power failures can cause irregular usage patterns, resulting in data that is not typical for the customer.
- Valid intervals from “partial” days can optionally be used for estimation. “Partial” days are defined as those containing

estimated data or those on which data collection began at some time other than midnight.

- Historical data up to a year with the exemption of holidays where several years may be used prior to the day needing estimation and from the current billing period may be used for estimation.
- Reference days are chosen to be the closest chronologically to the data needing estimation, regardless of seasonal crossover. This may include days after the day requiring estimation. If two potential reference days are equidistant from the day requiring estimation, use the earlier day first. For example, if June 2, 1998 needed estimation and the billing period was from June 1 to June 30, the reference days used would be May 19, May 26, and June 9, provided they contained valid data.

2.2.1. Develop a Daily Profile

1. Find the three “same weekdays” with valid data closest in time to the day with the data needing estimation based on the rules listed in the previous section. If the day with data needing estimation is a holiday, the “same weekdays” are holidays, not the same day of week. If not enough historical holidays exist in the current billing period or previous 90-day period, use Sundays. Calculate the average daily profile using the three selected days.
2. If only two same weekdays are available from the current billing period, year ago, and 90 days of historical data, calculate the average daily profile using the two selected days.
3. If only one same weekday is available from the current billing period, year ago, and 90 days of historical data, use it as the daily profile.
4. If no same weekdays are available in the current billing period, year ago, and 90 days of historical data, look for the three “like” days that are closest chronologically to the day with intervals needing estimation. For example, if the intervals needing estimation were on Tuesday, use Monday, Wednesday, and Thursday. Only use weekdays with weekdays; only use weekends with weekends; only use holidays or Sundays with holidays. Calculate the average daily profile using the three selected days.
5. If only two like days are available from the current billing period, year ago, and 90 days of historical data, calculate the average daily profile using the two selected days.
6. If only one like day is available from the current billing period, year ago, and 90 days of historical data, use it as the daily

profile with the exception of Holidays where more than one year ago data may be necessary

2.2.2. Use the Daily Profile to Estimate the Required Data

1. Estimate the data needing estimation by applying the appropriate intervals from the average daily profile to fill the missing intervals.
2. If start and stop meter readings are available and known to be good, they may optionally be used to scale the estimated interval data.

2.2.3. If there are no similar days or like days, use the load profile for the customer's class to estimate the data. Use this month's usage, if available, to scale the load profile. If this month's usage is not available, use last month's usage or last year's usage, whichever is determined to be more reasonable, to scale the load profile. Refer to the Utilities' load profile documentation for more information on applying load profiles. Note that the load profiles are for hourly data. If 15 minute data is required, assume a flat load throughout the hour (i.e., each 15-minute interval would have 1/4th the hourly usage).

2.2.3. If there are is no historical data that can be used, the data must be estimated manually and the process and assumptions documented.

2.3. Correcting Data Problems Attributable to Metering Problems

If on investigation the cause of the data problem is determined to be a problem with the meter or meter installation and the data can be corrected by scaling the intervals and meter readings, the MDSP will be notified of:

1. The time period requiring correction.
2. The scaling factor to be applied to each interval in that period.

Examples of these situations include a meter running slow, a meter running fast, one or two phases dropped, etc.

When the data is posted, it is marked as estimated if it had not been previously posted, and marked as adjusted if it had previously been posted

2.4. Interval in Meter doesn't Match Tariff or Settlement Requirements

If the meter programming and the MDSP requirements are inconsistent, the data is calculated as follows:

1. The meter is programmed to collect data at a smaller interval than required by its tariffs, and the meter's interval evenly divides into the interval required by the tariff – for example, the meter was programmed to collect 5-minute data, and the tariff requires 15-minute data. Sum the 5-minute intervals into 15-minute intervals on even 15-minute boundaries. If the data passed all the other validation checks, it is valid and does not need to be marked as estimated or verified.
2. The meter is programmed to collect data at a larger interval than required by the meter's tariff. For example, the meter is programmed to collect 60-minute intervals, but the tariff require 15-minute intervals. Prorate the data by assuming an even load distribution during the interval. In this example, the usage in the 60-minute interval would be divided by 4 to estimate the usage in a 15-minute interval. The data is marked as estimated. The meter must be reprogrammed to the correct interval.
3. The meter is programmed to collect data at a smaller interval than required by its tariff, but the meter's interval doesn't evenly divide into the interval required by the tariff. For example, the meter is programmed to collect 10-minute intervals, and the tariff requires 15-minute intervals. The data would be estimated and marked as estimated. To estimate data, all collected intervals that are contained within the required reporting interval are included in the appropriate reporting interval. Collected intervals that cross the boundaries of required reporting intervals are included proportionally in both reporting intervals. In this example, if there were three 10-minute intervals containing 10 kWh, 20 kWh, and 30 kWh, the corresponding estimated 15-minute intervals would contain 20 kWh ($10 + 0.5 \cdot 20$) and 40 kWh ($0.5 \cdot 20 + 30$).

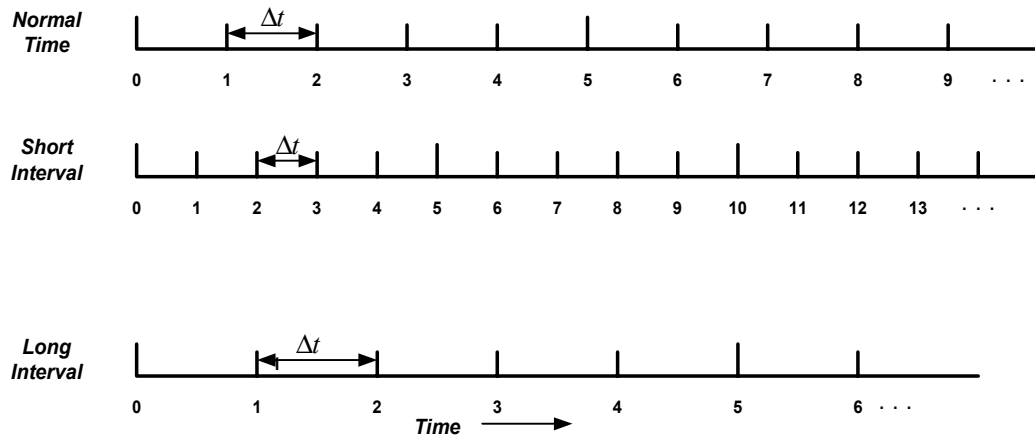
Appendix 6 - Interval Data VEE Technical Methods

1. Prorating Time Drifted Data

Two options are provided for correcting the data when the actual number of intervals retrieved from the meter does not equal the expected number of intervals based upon the elapsed time.

1.1. Option 1 for Prorating Time Drifted Data

This section describes how to normalize interval data when the clock in the meter does not agree with the clock in the computer reading the meter. This phenomenon is called Clock Drift. Clock drift can be both a negative or positive value, depending upon whether the real time (at the computer) is greater than [negative drift] or less than [positive drift] than the clock in the meter. This is illustrated below.



For each of the illustrations shown above, the actual interval of measurement is different. We assume that the meter and the computer systems are synchronized at some time, T_0 {for example, the last meter read} and that the meter is now being read at a read time, T_r . For each case above, assume that the meter reading system reads at the same time. The elapsed time is given by

$$\text{Elapsed Time} = \Delta T_e = T_r - T_0$$

The elapsed time for the shorter interval case is given by

$$\text{Short Interval Elapsed Time} = \Delta T_{es} = T_{ms} - T_0$$

where T_{ms} is the time that the meter clock gives when the meter is read.

The elapsed time for the longer interval case is given by

$$\text{Longer Interval Elapsed Time} = \Delta T_{el} = T_{ms} - T_0$$

where T_{ml} is the time that the meter clock gives when the meter is read. Note that $T_{ms} > T_0$, i.e. the meter clock is running faster therefore clocking more intervals and more elapsed time. And that $T_{ml} < T_0$, i.e., the meter clock is running slower, hence fewer intervals and a shorter elapsed time.

In each case, the internal clock in the meter is registering that the interval length is the length that is specified for the meter, namely Δt or 15 minutes for interval meters. However, since the clock is running faster for the short interval case and slower for the long interval case, we must adjust the values such that the correct usage is obtained for each meter. The total drift time for the clock can be calculated for each case as follows:

$$\begin{aligned} \text{Total Drift Time For Short Intervals } TD_s &= |\Delta T_e - \Delta T_{es}| \\ &= |T_r - T_{ms}| \end{aligned}$$

and

$$\begin{aligned} \text{Total Drift Time For Long Intervals } TD_l &= |\Delta T_e - \Delta T_{el}| \\ &= |T_r - T_{ml}| \end{aligned}$$

Note that TD_s would be negative had we not taken the absolute value.

The actual number of intervals for each case can be calculated using the elapsed time measured by the meter and dividing it by the preset meter interval, Δt or 15 minutes. Or when truncated to an integer:

$$\text{Expected Number of Intervals, } N = \Delta T_e / \Delta t$$

$$\text{Number of Short Intervals } N_s = \Delta T_{es} / \Delta t$$

$$\text{Number of Long Intervals } N_l = \Delta T_{el} / \Delta t$$

Two cases are considered.

Case # 1 is when $N = N_s = N_l$, i.e. the clock drift is small enough that no additional interval is generated. For this situation, we could elect to do nothing since for a thirty day reading schedule for 15 minute interval data, there will be about 2880 intervals and a time drift error of less than 0.04% in each interval. The

actual drift time for each interval, ignoring any fractional intervals at the end of the read period can be calculated as

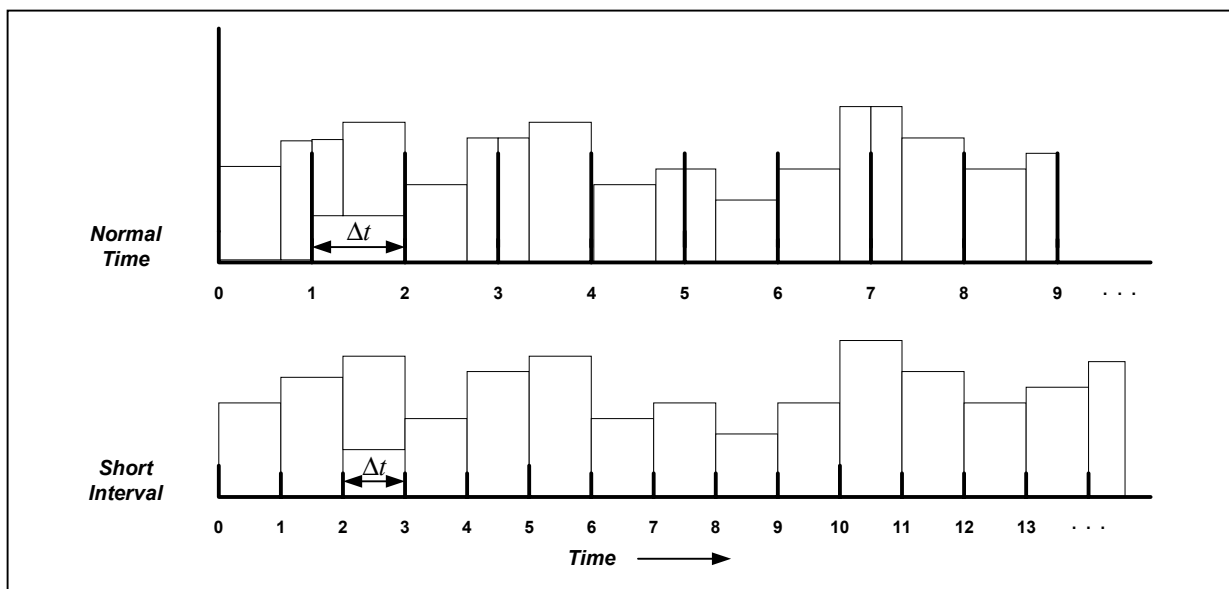
$$\Delta DT_s = TD_s / N$$

and for the long interval case,

$$\Delta DT_l = TD_l / N$$

This result could be used in combination with the actual interval width to increase or decrease the usage in the particular interval.

Case #2 involves a situation when $N \neq N_s$ or $N \neq N_l$ and hence there are a fewer or greater number of intervals that expected. Here we suggest that a procedure be adopted that distributes the measured interval values into intervals that have the correct length, namely Δt . Thus we increase or decrease the interval length to correspond to actual interval length that should have been in the meter based on the drift, $\Delta t + \Delta DT_l$ or $\Delta t - \Delta DT_s$. Thus the interval distribution that is shown in the above figure would now have proper interval lengths in minutes. The procedure for distribution this data is fairly straightforward. We simply insert the real 15-minute interval grid on the actual interval grid taken from the meter and adjusted by the above technique. Next we divide each of the obtained usage values at the corresponding 15-minute grid points.



This figure shows how to allocate each of the respective values. For example in the first corrected interval, the usage would

equal the sum of the usage in the incorrect time interval case plus the fraction to the left of the corresponding interval in the correct zone. For example, if the drift per interval was found to be 4 minutes for short interval case, then the time grid would be 0, 11, 22, 33, 44, 55, 66, 77, etc. The amount taken from the second short interval would be the usage in interval 2 multiplied by 4/11 or 34%. For the case of the third correct interval, there would be components from interval 3, 4, and 5 of the incorrect interval usage. From the third interval, it would be 3/11 of the usage, from the fourth interval it would be 100% of the usage, and from the fifth interval it would be 1/11 of the usage. This scheme should be easy to implement. The one caution is that additional manipulation of the usage data will be required if the interval values are stored as kW for the interval, rather than kWh/kVAh. But this should not be a problem.

1.2. Option 2 for Prorating Time Drifted Data

The objective of this algorithm is to create the expected number of intervals while preserving the usage recorded in the actual number of intervals.

When the Actual number > Expected Number...

- 1) Truncate the extra intervals.
- 2) The total usage will decrease by the amount recorded in the truncated intervals. In order to preserve the recorded usage, the usage in the remaining intervals will need to be scaled up as described below.

When the Actual number < Expected Number...

- 1) Interpolate using the last good interval to create the expected number of intervals.
- 2) The total usage will increase by the amount in the interpolated intervals. In order to preserve the recorded usage, the usage in each interval will need to be scaled down as described below.

To scale the usage in the truncated or interpolated intervals...

- 1) Calculate the recorded usage.

Recorded Usage = total usage for the period. It can be derived from the sum of the usage in the “actual” intervals or from good meter readings.

- 2) Calculate the pre-scaled usage.

Pre-scaled Usage = The total usage in the intervals after they have been truncated or interpolated to the expected number of intervals.

- 3) Calculate the scaling factor.

Scaling Factor = (Recorded Usage/Pre-scaled usage).

- 4) Multiply the usage in each interval by the scaling factor to create corrected usage. The sum of the usage in the scaled intervals should now be equal to the recorded usage.
- 5) Flag all intervals for the period as estimated.

2. Sum Check Failure Troubleshooting Techniques

The objective of the sum check is to compare the energy use recorded by the meter to the energy use recorded by the pulse recorder over the same time period. Due to data collection methods, often the period represented by the meter reads does not correspond exactly to the period represented by the interval data. For example, the period of data collection may span from 5/1/98 01:12 AM to 6/1/98 01:22 AM, with the meter readings corresponding exactly to this time period. With 15-minute interval data, the interval data for this same period of data collection would begin at 5/1/98 01:00 AM and end at 6/1/98 01:15 AM. The difference of 12 minutes from the start meter reading and 7 minutes from the end meter reading could be the source of error in the failure of the sum check.

2.1. Account for Start and End Time Differences

The following technique enables the MDSP to resolve sum check failures by taking into account time differences between the meter readings and the interval data.

Redo the sum check, taking into account the differences in time between the time of the start read and the start of the first interval, and the time of the stop read and the end of the last interval:

- 2.1.1. Calculate a prorated start meter reading to be used in this check by doing the following:
 - a. Calculate the percentage of an interval that has elapsed between the start time of the first interval and the time of the start meter reading. For example, if the meter was read at 3:30 PM, the first interval in an hourly interval data stream would start at 3:00 PM.

The percentage of time elapsed is $(30 \text{ min.}/60 \text{ min.}) = 50\%$.

- b. Multiply the usage from the first interval by the percentage from the previous step. For example, if the usage in the first interval is 240 kWh/kVAh, the percentage usage is $(240 * 0.50) = 120 \text{ kWh/kVAh}$.
 - c. Determine how many meter increments are represented by the percentage usage from the previous step. For a meter multiplier of one, the usage is equal to the number of meter increments, so 120 kWh/kVAh is equal to 120 meter increments. For a meter multiplier of 80, 120 kWh/kVAh is equal to 1 meter increment (i.e., 120 divided by 80 and rounded down to the nearest integer).
 - d. Calculate a prorated start meter reading by subtracting the number of meter increments from the previous step from the actual start meter reading. For example, if the start meter reading is 55555, and the number of meter increments is equal to 120, the prorated start meter reading would be $(55555 - 120) = 55435$.
- 2.1.2. Calculate an allowable margin of error to be used in this check by doing the following:
- a. Calculate the percentage of an interval that has elapsed between the end time of the last interval and the time of the stop meter reading. For example, if the meter was read at 11:15 AM, the last interval in an hourly interval data stream would start at 11:00 AM. The percentage of time elapsed is $(15 \text{ min.}/60 \text{ min.}) = 25\%$.
 - b. Multiply the usage from the last interval by the percentage from the previous step. For example, if the usage in the last interval is 120 kWh/kVAh, the percentage usage is $(120 * 0.25) = 30 \text{ kWh/kVAh}$.
 - c. Determine how many meter increments are represented by the percentage usage from the previous step. For a meter multiplier of one, the usage is equal to the number of meter increments, so 30 kWh/kVAh is equal to 30 meter increments. For a meter multiplier of 80, 30 kWh/kVAh would result in .375 meter increments.

- d. Calculate the allowable margin of error by adding 2 to the value calculated in the previous step.
- e. Redo the sum check using the prorated start and original stop meter readings and the allowable margin of error instead of the two multipliers.

2.2. Account for Missing or Incomplete Intervals

With some metering and data collection technologies, it is possible for the meter or cumulative usage register to reflect accurate usage even when the interval data is missing or incomplete. The following technique enables the MDSP to resolve the sum check failure for those intervals that were successfully collected.

If some intervals are missing or incomplete, redo the sum check after scaling the difference between the adjusted start read and the stop read by the percentage of good intervals:

- 2.2.1. Count the number of good intervals in the data stream.
- 2.2.2. Calculate the percentage of good intervals by dividing the count from the previous step by the number of intervals elapsed between start time and stop time.
- 2.2.3. Multiply the percentage by the difference between the start reading and the stop reading. (Note that you may use the actual start and stop readings or the prorated start and stop readings from 1.2.1 in this step.)
- 2.2.4. Compare the new difference with the sum of the usage in the good intervals. Note that the values must be in the same units for the comparison.
- 2.2.5. If the difference is \leq allowable margin from 1.2.1, the good intervals pass the sum check. The missing or incomplete intervals need to be estimated.

3. Scaling estimated data using good meter readings

If start and stop meter readings are available and are known to be good, they may optionally be used to scale the estimated interval data as follows:

- 3.1. Determine the total usage for the time period based upon the meter readings.

$$\text{Total Usage} = ((\text{Stop Reading} - \text{Start Reading}) * \text{Meter Multiplier})$$

- 3.2. Sum together the valid intervals.
- 3.3. Subtract the sum of the valid intervals from the total usage to determine the total estimated usage.

Total Estimated Usage = Total Usage – Sum of Valid Intervals

- 3.4. Sum together the previously estimated intervals.
- 3.5. Calculate the scaling factor by dividing the total estimated usage by the sum of the estimated intervals.

Scaling Factor = Total Estimated Usage/Sum of Estimated Intervals

- 3.6. Multiply each estimated interval by the scaling factor.

Appendix 7 – Monthly Data Validating, Editing, and Estimating Rules

Monthly Data Collection and Validation Rules

Some monthly data validation checks must be done at the time of meter reading, and other checks could be done anytime after the meter is read until the data is posted. For example, the meter identification check must be performed at the time of the meter reading, while the high/low usage check can be performed in a handheld system as the meter is read, or back in a host system. All checks are not applicable to all types of data. The following table summarizes which checks must be done for each type of data, and provides a recommended sequence.

Check	Must be done at time of meter read?	Consumption	Demand	TOU Consumption	TOU Demand
Time in meter	Yes	n/a	n/a	3	3
High/Low usage	No	3	n/a	4	n/a
High/Low demand	No	n/a	3	n/a	4
TOU usage	No	n/a	n/a	6	n/a
Zero consumption for active meters	No	4	n/a	5	n/a
Number of dials	Yes	2	n/a	2	n/a
Number of demand decimal places	Yes	n/a	2	n/a	2
Meter ID	Yes	1	1	1	1

Most of the checks and estimation algorithms are based on historical data for the same customer and the same site. In areas with wide fluctuations in weather, this may not provide the best data for residential customers, as residential usage patterns vary much more with changes in weather than larger customers. A separate set of High/Low usage validation check and estimation rules are provided based on day-before usage of similar customers in the same geographic area. The estimation check requires a minimum

density of meter population to be statistically accurate; this still needs to be determined.

1.1. Time Check of Meter Reading Device/System

This check only applies for meter reading devices and systems collecting Time-of-Use data. Time check of meter reading device/system ensures that the collection device is synchronized to a national time standard before data collection begins

1.2. Time Tolerance Check of Meter

The time tolerance check is only required if the meter is collecting Time-of-Use (TOU) data. It verifies that the meter's time is correct, and that TOU data represents the appropriate time periods. Note that depending on the communication technology used, network latency must be taken into account.

1.2.1. If time in meter is within +/- 3 minutes of the time standard, the data has passed Time Tolerance check. Note that if the meter is within +/- 3 minutes of the standard, the time in the meter can optionally be corrected.

1.2.2. If time in meter is off > 3 minutes but <= 55 minutes, the data passes the Time Tolerance check. The data does not need to be estimated, but the MDSP must record the fact that the meter's time was off by this amount in case there is a later question about the data. The meter time must be reset.

1.2.3. If time in meter is off > 55 minutes, the data fails the time tolerance check and must be estimated. The time in the meter must be reset. If the meter fails the time tolerance check after being reset for three consecutive months, the meter must be physically inspected/tested.

1.3. High/Low Usage

The High/Low Usage check validates cumulative consumption (kWh/kVAh). Two methods are provided - one based on historical data, and one based on previous day data from similar customers. An MDSP may implement either check, depending on weather characteristics and density of meter population served by the MDSP. The second check requires a minimum density of meter population to be statistically accurate; this still needs to be determined.

1.3.1 Method based on historical data

1.3.1.1. Calculate the average daily usage (ADU) for the present billing period.

For example, if all constants and factors have already been applied to the reads, the ADU could be calculated by:

$$\text{ADU} = (\text{current billing read} - \text{previous billing read}) / (\# \text{ days between billing reads})$$

If the previous billing read were on June 1, and the present billing read is on June 30, there would be 29 days between billing reads.

1.3.1.2. Calculate the Historical ADU

1.3.1.2.1 If there is not at least one month (minimum 27 days) of historical billing data available for the same customer and site, this check is not performed.

1.3.1.2.2. If data for the same customer and site is available, calculate the ADU for the same billing period last year. Use this as the historical billing ADU. One way to determine which billing period last year is “the same” is to choose the mid-point of this year’s billing period, and find the billing period last year that included the same date. For example, if the billing period this year was from April 13 to May 13, the mid-point would be April 28. If the billing period has an even number of days, use the day after the middle as the mid-point. For example, if the billing period was from June 1 to June 30, the mid-point would be June 16. Another way to determine which billing period is “the same” is to find the billing period last year with its read date in the same calendar month as the read date of the data being validated.

1.3.1.2.3. If there is no data from a year ago but there is data for the last billing period (minimum 27 days), calculate the ADU for the last billing period and use this as the historical ADU.

1.3.1.3. Compare the present billing period ADU with the historical billing period ADU. If the present billing period ADU is between 40% and 200% (inclusive) of the historical ADU, the data passes this check. (Note that some systems may convert ADU to a billing period usage to perform the check.) Optional trend factors that take into account peer group usage based on demographics, climactic areas, and customer class may be applied to the ADU to refine the High/Low comparison check. Sample trend factor calculations are to be provided at a later date.

1.3.1.4. If the present billing period ADU is not within 40% to 200% (inclusive) of the historical billing period ADU, the data fails this check. Optionally re-read the meter.

1. If the reread is essentially at the same time as the original read and a different value is obtained, assume the first reading was a misread and perform the check again with the new reading. If the same reading was obtained, assume the meter reading is correct; the data failed the High/Low Usage check but is verified.

OR

2. If the reread is not at the same time as the original read, re-compute the average daily usage using the new reading. If the new ADU is within +/- 20% of the previous ADU, the data fails the High/Low usage check but is verified. If the new ADU is not within +/- 20% of the previous ADU, the data fails the High/Low usage check.

1.3.1.5. Data that fails the High/Low usage check and has not been verified may be investigated and manually verified if justification is found; otherwise the data must be estimated.

1.3.2. Method Based on Previous Day Usage of Similar Customers

Note that this method requires a certain density of customer data for residential customers in the same geographic area, where weather patterns are typically consistent throughout the geographic area.

1.3.2.1. The following steps are performed at the end of each meter reading cycle day for each geographical area in order to validate and estimate usage the following day:

- 1.3.2.1.1. At the end of the reading day, for each good meter read (open account, billed, between 27-33 days & ADU \leq 100), perform the following calculations to determine an ADU for the billing period:
1. Calculate ADU (= KWH/KVAH/days in billing period)
 2. Add ADU to Sum of Current ADU
 3. Calculate ADU squared
 4. Add ADU squared to Sum of Current ADU squared
 5. Add 1 to total meters
 6. Calculate last month's ADU
 7. Calculate current ADU times last month's ADU
 8. Calculate last month's ADU squared
- 1.3.2.1.2. Determine which range of usage (high, medium or low) the current ADU should be grouped with by comparing current ADU to yesterday's ADU Low and High Range Factors (Reference 1.3.2.1.3 for ADU low and high range factor calculation methodology)
1. If the current ADU is less than yesterday's ADU low range factor:
 - Add current ADU to Sum of current low ADU
 - Add last month's ADU to Sum of last month's low ADU
 - Add current ADU times last month's ADU to Sum of current low ADU times last month's ADU
 - Add current ADU squared to Sum of current low ADU squared
 - Add last month's ADU squared to Sum of last month's low ADU squared
 - Add 1 to total low meters
 2. If the current ADU is not less than the ADU low range factor from yesterday and is less than the ADU high range factor, add the figures to the medium range following same format as in 1.3.2.1.2. step 1.
 3. Otherwise, add the current ADU to the ADU high range following the same format as in 1.3.2.1.2. step 1.

- 1.3.2.1.3. Calculate an aggregated ADU for current data for each geographic area
- 1.3.2.1.3.1. Sum together the ADU values for each geographic area
 - 1.3.2.1.3.2. Calculate the mean for the total ADU (=Sum of Current ADU / total meters)
 - 1.3.2.1.3.3. Calculate the standard deviation for the total
 - 1.3.2.1.3.4. Calculate the current ADU low and high range factors:
 - ADU Low Range Factor = mean - .43 Standard Deviation. If ADU Low range factor is less than the total current mean * .5, the ADU low range factor becomes the mean half.
 - ADU High Range Factor = mean + .43 Standard Deviation
 - NOTE: By determining the low & high factors, the Medium Range = (mean - .43 Standard Deviation) to (mean + .43 Standard Deviation)
- 1.3.2.1.4. For each of the three ranges determined above (low, medium, and high), calculate a percent of change of monthly usage for each geographic area.
- 1.3.2.1.4.1. After each meter's current billing period's (ADU) is grouped in 3 Ranges (Low, Medium, and High) as specified in 1.3.2.1.2, the following data are summed up by ADU range and area:
 - Number of customers
 - Sum of all last month's ADU
 - Sum of all current month's ADU
 - Sum of {each last month's ADU times current month's ADU}
 - Sum of {all last month's ADU squared} i.e., Square all ADU, then sum them.
 - Sum of {all current month's ADU squared}

From the data above modified ADU mean factors and standard deviation factors are determined for each range as follows:

Modified Mean Factor:

Sum of {last month ADU times current month ADU} divided by the sum of {all last month's ADU squared}

Modified Standard Deviation Factor:

Step 1: (Sum of {all current month's ADU squared} minus (Mean squared times sum of {all last month's ADU squared})) divided by (Total Meters minus 1).

Step 2: Take square root of Step 1

- 1.3.2.1.5. Calculate high and low range factors. Calculate high and low range factors (HRF and LRF) for each of the 3 usage ranges within a geographic area. The mean is used to calculate estimated reads, and the high and low range factors are used in this validation check. 2.8 and 3.5 are used in the below example to represent the range deviation factor and will allow for an appropriate meter read error rate. This factor can be changed to control the error rate.

High Range Factor Formula:

$$\text{HRF} = 1 + \{(2.8 \times \text{Modified Standard Deviation} \times \text{Number of meters}) / (\text{Sum of Current month's ADU})\}$$

Low Range Factor Formula:

$$\text{LRF} = 1 - \{(3.5 \times \text{Modified Standard Deviation} \times \text{Number of meters}) / (\text{Sum of Current month's ADU})\}$$

- 1.3.2.2. As each meter is read, perform the following using the values calculated from the previous meter reading days' data.
- 1.3.2.2.1. Determine the usage from the preceding billing month and the preceding billing reading for the customer and site.
- 1.3.2.2.2. Calculate low limit for this month's usage by multiplying the preceding month's usage by the low range factor determined above.

- 1.3.2.2.3. Calculate high limit for this month's usage by multiplying the preceding month's usage by the high range factor determined above.
- 1.3.2.2.4. If the current usage is between the low and high limit calculated in the previous two steps, the data passes the High/Low check.

The following is a representation of how the High and Low Range Factors are used to validate meter usage:

Sample High/Low Usage Check:

Customer's previous usage = 400 kWh/kVAh

High Range Value: 400kWh/kVAh X 1.115 HRF* = 446

Low Range Value: 400kWh/KvAh X .885 LRF* = 354

Usage values falling between 354 and 446 are accepted. Usage values outside this range fail the check.

* HRF/LRF = High and Low Range Factors, see description above.

- 1.3.2.2.5. If the current usage is outside the low and high limit, the data fails the High/Low check. Optionally re-read the meter.
 1. If the reread is essentially at the same time as the original read and a different value is obtained, assume the first reading was a misread and perform the check again with the new reading. If the same reading was obtained, assume the meter reading is correct; the data failed the High/Low Usage check but is verified.

OR

 2. If the reread is not at the same time as the original read, re-compute the average daily usage using the new reading. If the new ADU is within +/- 20% of the previous ADU, the data fails the High/Low usage check but is verified. If the new ADU is not within +/- 20% of the previous ADU, the data fails the High/Low usage check.
- 1.3.2.2.6. Data that fails the High/Low usage check and has not been verified may be investigated and

manually verified if justification is found;
otherwise the data must be estimated.

1.4. High/Low Demand

The High/Low Demand Check compares the demand against historical data as a reasonableness check.

1.4.1. Determine the peak demand for this billing period.

1.4.2. Determine the historical peak demand.

1.4.2.1. If there is not at least one month (at least 27 days) of historical billing demand data available, skip this check.

1.4.2.2. If demand data for this customer and site is available for the same billing period last year, use that as the historical peak demand. (Refer to section 1.3.1.2.2 to determine same billing period last year.)

1.4.2.3. If demand data is not available for the same billing period last year but there is demand data for the last billing period, use the peak demand from the preceding billing month as the historical peak demand.

1.4.3. Compare the present peak demand with the historical peak demand. If the present peak demand is between 40% and 200% of the historical peak demand, the data passes this check.

1.4.4. If the present peak demand is not within 40% to 200% of the historical peak demand, the data fails the High/low demand check. Optionally re-read the meter if the same data is still available in the meter. For example, the same data would still be available if demand reset has not yet been performed or meter stores preceding billing period data.

1. If the reread is essentially at the same time as the original read and a different value is obtained, assume the first reading was a misread and perform the check again with the new reading. If the same reading was obtained, assume the meter reading is correct; the data failed the High/Low Demand check but is verified.

OR

2. If the reread is not at the same time as the original read and the new demand value is within +/- 20% of the previous demand value, the data fails the High/Low demand check but is verified. If the re-read results in the same value, the data fails the High/Low demand check but is verified.

1.4.5 Data that fails the High/Low Demand check and has not been verified may be investigated and manually verified if justification is found. Otherwise the data must be estimated.

1.5. TOU Usage

The TOU usage check compares the sum of the kWh/kVAh meter readings for all periods against the current season total kWh/kVAh meter reading. Note that this check must be done in whatever units are read from the meter. For example, if the meter provides kWh/kVAh, the kWh/kVAh values must be summed and compared. If the meter provides pulses, the pulse values must be summed and compared.

1.5.1. For the current billing period, calculate the total kWh/kVAh by summing all the periods, including all seasons.

1.5.2. Compare the calculated total kWh/kVAh with the current total kWh/kVAh read from the meter. If they are within +/- the number of periods (active or inactive) summed together, the data passes the check. If they are not, the data fails the TOU Usage check and must be estimated. (Note: some TOU rates may include more periods in one season than another, causing "inactive" periods. For example, a summer season may have three periods, and a winter season only two. The period that appears only during the summer is "inactive" during the winter season.)

For example, assume there were two periods, peak and off-peak, and a season change occurred during the month.

Period	Previous Season	Current Season
Peak	50	150
Off-Peak	100	200

Determine the valid range by calculating the sum of the periods +/- the number of periods, or $(50 + 100 + 150 + 200) \pm 2$. If the current total kWh/kVAh read from the meter was between 498 and 502 inclusive, the data would pass the check. If the current total kWh/kVAh read from the meter was less than 498 or greater than 502, the data would fail the check.

If the meter is programmed to provide readings for all but one of the periods, this test is modified to verify the sum of the periods with readings is \leq the total kWh/kVAh.

1.6. Zero Consumption for Active Meters

The Zero Consumption checks for zero usage during the billing month.

- 1.6.1. If the meter is an active meter (i.e., is associated with a customer who has financial responsibility), calculate the usage for the present billing month.
 - 1.6.2. If the usage is greater than 0, the data passes the zero consumption check.
 - 1.6.3. Data that fails the zero consumption check may be manually investigated and verified if justification is found (for example, a building or equipment that is only used seasonally). If the data is not validated or verified, it must be estimated.
 - 1.6.4. If the usage is 0, the data failed the zero consumption check. Optionally verify the meter reading by re-reading the meter and/or testing the meter. If the reread is the same and the usage is still 0, the data failed the Zero Consumption check but is verified. If a new, different meter reading is obtained, run all the checks again using the new data
- 1.7. Usage for Inactive Meters
An inactive meter is one for which there is no customer with financial responsibility. This does not apply to non-UDC MDSPs and is not a required check.
- 1.8. Number of Dials on Meter
This check applies to cumulative consumption only. It checks that the number of “dials” (digits) reported in the read is consistent with the number of dials (or digits) on the meter display. This check is performed for both remote and local reads if supported by the meter reading technology. If the meter reading technology doesn’t support this check, it is not performed.
 - 1.8.1. Determine the number of digits in the meter reading.
 - 1.8.2. If the number of digits in the meter reading is consistent with the number of digits/dials on the meter, the data passes this check.
 - 1.8.3. If the number of digits is not consistent, re-read the meter to verify that the correct meter is being read and that it has the correct number of digits/dials. If the re-read provides the same values, the meter reading failed the Number of Dials on Meter check but is verified. The situation must be investigated and records must be corrected. If the re-read produces different values, perform the check again with the new values.
- 1.9. Meter Read Demand Decimal Quantity Difference
The Meter Read Demand Decimal Quantity Difference check verifies that the number of demand decimal places displayed on the meter is correct. Note this check is only performed for on-site meter reads, and is not performed for remote meter reads.
 - 1.9.1. When the meter is read on-site, the meter reader compares the number of decimal places displayed by the meter with the

number of decimal places expected. If they are the same, the reading passes the Meter Read Dial Decimal Quantity check.

- 1.9.2. If they are not the same, re-read the meter to verify that the correct meter is being read and that it has the correct number of decimal places. If the re-read provides the same values, the meter reading failed the Meter Read Dial Decimal Quantity Difference check but is verified. The situation must be investigated and records must be corrected. The meter may need to be re-programmed. If the re-read produces different values, perform the check again with the new values.

1.10. Meter Identification

There are two types of Meter Identification checks depending on how the meter is read - Internal Meter Identification check and External Meter Identification check. The following table summarizes when each check is required:

Meter Reading Method	Perform External ID Check?	Perform Internal ID Check?
Remote	No	Yes
Optical Port	Yes	Yes
Manual	Yes	No

1. If the meter is read remotely or via its optical port, the Internal Meter Identification check is performed. This compares the meter's internal identification (often its serial number) with the identification expected by the meter reading system. If they match, the data passes this check. If they don't match, the MDSP must investigate why the meter is different than indicated by their records and resolve the inconsistency
2. If the meter is read locally (including via an optical port), the External Meter Identification Check is performed. This compares the Meter ID on the meter nameplate with the Meter ID expected by the meter reading system. If they match, the data passes this check. If they don't match, the MDSP must investigate why the meter is different than indicated by their records and resolve the inconsistency.

1.11. Irregular Usage Monthly Data

An irregular usage customer is one whose usage pattern at a specific location does not follow normal usage patterns and consistently fails the High/Low usage or zero consumption for active meters checks. A customer may be determined to be an irregular usage customer by an MDSP if the MDSP verifies that:

1. the customer data fails the standard validation check for three consecutive months, and that the data represents the actual customer usage,

OR

2. the MDSP is notified by the customer's previous MDSP.

The data used to determine a customer is an irregular usage customer could be data collected by the MDSP, or historical data provided by the previous Energy Supplier or MDSP. An Energy Supplier may notify the MDSP that a customer is a potential irregular usage customer based on conversations with the customer, triggering an inspection of the data. If a customer is determined to be an irregular usage customer, the MDSP may optionally omit the check the customer normally fails. For example, if an irregular usage customer typically fails the High/Low usage check but not the zero consumption check, the zero consumption check must still be performed but the high/low usage check may be omitted. The MDSP must notify both the customer's Energy Supplier and UDC of the customer's irregular usage status and what checks will not be performed.

For some customers, irregular usage patterns are symptomatic of the business and will always be present, such as agricultural or seasonal customers. For other customers, irregular usage patterns may be a temporary condition, such as when a factory adds a second shift and fails the high/low usage check for the first 12 months. The MDSP must determine whether a customer is a permanent or temporary irregular usage customers. Temporary irregular usage customers must be reviewed at least annually to determine if they are still irregular usage customers or should be returned to the normal checks.

Monthly Data Estimation Rules

Note that the MDSP must record the estimation algorithm used for each data element that is estimated. The MDSP must retain this information for the same period required for raw and validated data (3 years). Monthly data estimation algorithms include:

- Estimation based on previous year's data
- Estimation based on preceding billing period's data (≥ 27 days)
- Estimation based on similar customers
- Estimated demand based on average load
- Other estimation method (MDSP must document when this is used)

2.1. Estimating Usage

Two methods to estimate usage are provided. They are similar to the two methods of performing the High/Low Usage check. The first is based on historical usage for the same customer and site; the second is based on historical usage for the same customer and site combined with a factor based on present usage of customers of the same class and same geographic area. The number of decimal places included in ADU calculations must be sufficient so that significant rounding errors do not occur. The recommended value is 2 decimal places. Final estimated usage is truncated to an integer.

2.1.1. Method 1 - Based on Historical Usage

2.1.1.1. Calculate ADU to be applied

2.1.1.1.1. If billing data is available from the same customer and same site for the same billing period last year and it is not estimated, calculate the ADU for the same billing period last year and use this value as the ADU. Refer to section 1.3.1.2.2 to determine the same billing period last year. Optional trend factors that take into account peer group usage based on demographics, climactic areas, and customer class may be applied to the ADU to provide a more accurate estimation. Sample trend factor calculations are to be provided at a later date.

In this case, the estimation algorithm is estimation based on previous year's data.

2.1.1.1.2. If there is no data from the previous year but there is a full preceding billing month (at least 27 days) calculate the ADU for the preceding billing month and use this value for the ADU. In this case, the estimation algorithm is estimation based on preceding billing period's data.

2.1.1.1.3. If neither of the previous two options are available, data must be estimated based on any available data, such as similar customers, load profiles, average usage for the customer class, meter reads since last billing read, other historical data, etc. In this case, the estimation algorithm is other estimation algorithm. The MDSP must document how the data is estimated.

2.1.1.2. Calculate the number of days since the last good meter reading within the current billing cycle to the

end of this billing period. If the meter is read monthly, this would typically be last month's billing meter reading. If the meter is read more frequently, this could be more recent than last month's billing reading.

2.1.1.3. Multiply the ADU (including any constants or factors) by the number of days since the last good reading. If necessary, divide this value by a meter constant or other factor to convert it to the same units reported in the meter reading. Truncate the value to an integer, and add the truncated value to the last good reading to obtain an estimated reading. This is the estimated meter reading. Mark the reading as being estimated using the appropriate algorithm.

2.1.2. Method 2 - Based on historical usage and similar customers

2.1.2.1. For the residential meter population (i.e., same geographic area and customer class), utilize the following determinants as determined in 1.3.2:

- ADU Low Range Factor (1.3.2.1.3.4)
- ADU High Range Factor (1.3.2.1.3.4)
- Low Range Modified Mean Factor (1.3.2.1.4.1)
- Medium Range Modified Mean Factor (1.3.2.1.4.1)
- High Range Modified Mean Factor (1.3.2.1.4.1)

2.1.2.2. Calculate the ADU from last month's billing period for that customer.

2.1.2.3. Calculate the modified ADU for a specific meter by multiplying last month's ADU (from step 2.1.2.2) by yesterday's medium range modified mean factor (above) for that geographical area.

2.1.2.4. Determine if the modified ADU is in yesterday's low, medium, or high range.

- If the modified ADU is less than the ADU low range factor, yesterday's low range modified mean factor is used to calculate estimated ADU in the succeeding steps.
- If the modified ADU is equal to or greater than ADU low range factor but less than the ADU high range factor, yesterday's medium range modified mean factor is used to calculate estimated ADU in the succeeding steps.

- If the modified ADU is greater than or equal to the ADU high range factor, yesterday's high range modified mean factor is used to calculate estimated ADU in the succeeding steps.
- 2.1.2.5. Multiply the prior ADU by the modified mean factor determined in 2.1.2.4. This becomes the new estimated ADU.
 - 2.1.2.6. Continue with steps 2.1.1.2, and 2.1.1.3 using the estimated ADU calculated in the preceding step.

2.2. Estimating Demand

- 2.2.1. If demand data is available from the same customer and same site for the same billing period last year and it is not estimated, use that demand as the estimated demand. Refer to section 1.3.1.2.2 to determine the same billing period last year. In this case, the estimation algorithm is estimation based on previous year's data.
- 2.2.2. If there is no demand data from the previous year but there is demand data from a full preceding billing month (at least 27 days), use the preceding month's demand as the estimated demand. In this case, the estimation algorithm is estimation based on preceding billing period's data
- 2.2.3. If neither of the above two options are available, calculate the average demand for the billing period. This is done by dividing the actual or estimated usage by the number of hours in the billing period. Use this value as the estimated demand. For example, if the billing period is 30 days, divide the usage for the billing period by 720 (the number of hours in 30 days)

2.3. Estimating TOU Usage

For missing TOU usage data, each period must be estimated separately, using historical data from the same TOU period (defined by time frames) and season as the data requiring estimation. Optional trend factors that take into account peer group usage based on demographics, climactic areas, and customer class may be applied to the ADU to provide a more accurate estimation. Sample trend factor calculations are to be provided at a later date. The number of decimal places included in ADU calculations must be sufficient so that significant rounding errors do not occur. The recommended value is 2 decimal places. Final estimated usage is truncated to an integer.

- 2.3.1. For each period requiring estimation, the following steps are performed. Note that if there is a season change during the time period requiring estimation, each season needs to be done separately. If season crossover occurs in the month requiring estimation, reference data could be selected from the last month

with crossover between the same seasons, or the last full month of the season. There are two cases to consider. For example:

1. If season changes occur on October 1 and May 1, and the billing month April 15 to May 15 (including the season crossover) requires estimation, reference data for the winter period may be chosen from the billing period that contained the October 1 crossover, or from the preceding billing month. Reference data for summer could be chosen from the billing period that contained the October 1 crossover, or from the last full summer month. If the reference month selected does not contain the same seasons as the month requiring estimation, an appropriate month containing the correct seasons should be selected.
2. If season changes occur on October 1 and May 1, and the billing month May 15 to June 15 requires estimation, reference data may be chosen from the billing period that contained the last full month of summer data, or from the summer portion of the preceding billing month.

2.3.1.1. Calculate ADU to be applied

- 2.3.1.1.1. If billing data is available from the same customer, same site, and same TOU period for the same billing period last year, and last year's data is not estimated, calculate each period's ADU for the same billing period last year and use the values as each period's ADU. Refer to section 1.3.1.2.2 to determine the same billing period last year. For example, if the billing period this year was from April 13 to May 13, the mid-point would be April 28. If a season change occurred during the month, use data from the appropriate season as reference data. Optionally, use data from the month before or after the same billing period last year to get at least one week's worth of data for the season. In this case, the estimation algorithm is estimation based on previous year's data.
- 2.3.1.1.2. If there is no data from the previous year but there is at least one month's data (minimum 27 days) available from the preceding billing month and it is not estimated, calculate each period's ADU for the preceding billing month and use the values for each period's ADU. If a season change occurred during the month, use data from the appropriate season as reference data. Optionally, use data from the month

before or after the same billing period last year to get at least one week's worth of data for the season. In this case, the estimation algorithm is estimation based on preceding billing period's data.

2.3.1.1.3. If there is less than one week's historical data available, each period's data must be estimated by other methods based on any available data, such as similar customers, load profiles, average usage for the customer class, meter reads since last billing read, other historical data, etc. In this case, the estimation algorithm must be documented. The estimation algorithm is other estimation algorithm.

2.3.1.2. Calculate the number of days since the last good meter reading within the current billing cycle to the end of this billing period for each period requiring estimation. If the meter is read monthly, this would typically be last month's billing reading. If the meter is read more frequently, this could be more recent than last month's billing reading.

2.3.1.3. For each period, multiply the ADU for that period by the number of days requiring estimation. This is the estimated usage by period. Sum the periods to derive the total estimated usage for the billing period. Mark the reading as being estimated using the appropriate algorithm.

2.4. Estimating TOU Demand Data

For missing TOU demand data, estimate each period required for billing separately. Note that if there is a season change during the time period requiring estimation, each season needs to be done separately.

2.4.1. For each period requiring estimation, the following steps are performed. Note that if there is a season change during the time period requiring estimation, each season needs to be done separately. If season crossover occurs in the month requiring estimation, reference data could be selected from the last month with crossover between the same seasons, or the last full month of the season. There are two cases to consider. For example:

1. If season changes occur on October 1 and May 1, and the billing month April 15 to May 15 (including the season crossover) requires estimation, reference data for the winter period may be chosen from the billing period that contained the October 1 crossover, or from the preceding billing month.

Reference data for summer could be chosen from the billing period that contained the October 1 crossover, or from the last full summer month. If the reference month selected does not contain the same seasons as the month requiring estimation, an appropriate month containing the correct seasons should be selected.

2. If season changes occur on October 1 and May 1, and the billing month May 15 to June 15 requires estimation, reference data may be chosen from the billing period that contained the last full month of summer data, or from the summer portion of the preceding billing month.
 - 2.4.1.1. If demand data is available from the same customer and same site for the same billing period last year and it is not estimated, use that demand as the estimated demand. Refer to section 1.3.1.2.2 to determine the same billing period last year. In this case, the estimation algorithm is estimation based on previous year's data.
 - 2.4.1.2. If there is no demand data from the previous year but there is demand data from a full preceding billing month (at least 27 days), use the preceding month's demand as the estimated demand. In this case, the estimation algorithm is estimation based on preceding billing period's data.
 - 2.4.1.3. If neither of the above two options are available, calculate the average demand for the billing period. This is done by dividing the actual or estimated usage by the number of hours in the billing period. Use this value as the estimated demand. For example, if the billing period is 30 days, divide the usage for the billing period by 720 (the number of hours in 30 days).

Appendix 8 - Monthly Data VEE Technical Methods

This attachment provides an example of validating and estimating usage based on previous day usage of similar customers. The numbers in brackets to the left of the text correspond to the numbers on the spreadsheet at the end of this appendix.

1. Method Based on Previous Day Usage of Similar Customers
Note that this method requires a certain density of customer data for residential customers in the same geographic area, where weather patterns are typically consistent throughout the geographic area.
 - 1.1 The following steps are performed at the end of each meter reading cycle day for each geographical area in order to validate and estimate usage the following day:
 - 1.2 At the end of the reading day, for each good meter read (open account, billed, between 27-33 days & ADU \leq 100), perform the following calculations to determine an ADU for the billing period:
 - 1.2.1 Calculate ADU (= KWH/KVAH/days in billing period) [1]
 - 1.2.2 Add ADU to Sum of Current ADU
 - 1.2.3 Calculate ADU squared [2]
 - 1.2.4 Add ADU squared to Sum of Current ADU squared
 - 1.2.5 Add 1 to total meters
 - 1.2.6 Calculate last month's ADU [3]
 - 1.2.7 Calculate current ADU times last month's ADU [4]
 - 1.2.8 Calculate last month's ADU squared [5]
 - 1.3 Determine which range of usage (high, medium or low) the current ADU should be grouped with by comparing current ADU to yesterday's ADU Low and High Range Factors (Reference 1.4 for ADU low and high range factor calculation methodology) [6]
 - 1.3.1 If the current ADU is less than yesterday's ADU low range factor:
 - Add current ADU to Sum of current low ADU
 - Add last month's ADU to Sum of last month's low ADU
 - Add current ADU times last month's ADU to Sum of current low ADU times last month's ADU
 - Add current ADU squared to Sum of current low ADU squared
 - Add last month's ADU squared to Sum of last month's low ADU squared
 - Add 1 to total low meters
 - 1.3.2 If the current ADU is not less than the ADU low range factor from yesterday and is less than the ADU high range

factor, add the figures to the medium range following same format is in 1.3.1.

1.3.3 Otherwise, add the current ADU to the ADU high range following the same format in 1.3.1.

1.4 Calculate an aggregated ADU for current data for each geographic area.

1.4.1 Sum together the ADU values for each geographic area. [7]

1.4.2 Calculate the mean for the total ADU (=Sum of Current ADU / total meters) [8]

1.4.3 Calculate the standard deviation for the total [9]

1.4.4 Calculate the current ADU low and high range factors:

- ADU Low Range Factor = mean - .43 Standard Deviation. [10] If ADU Low range factor is less than the total current mean * .5, the ADU low range factor becomes the mean half. [11]
- ADU High Range Factor = mean + .43 Standard Deviation
- NOTE: By determining the low & high factors, the Medium Range = (mean - .43 Standard Deviation) to (mean + .43 Standard Deviation) [12]

1.5 For each of the three ranges determined above (low, medium, and high), calculate a percent of change of monthly usage for each geographic area.

1.5.1 After each meter's current billing period's (ADU) is grouped in 3 Ranges (Low, Medium, and High) as specified in 1.3, the following data are summed up by ADU range and area:

- Number of customers [13]
- Sum of all last month's ADU [14]
- Sum of all current month's ADU [15]
- Sum of {each last month's ADU times current month's ADU} [16]
- Sum of {all last month's ADU squared} i.e., Square all ADU, then sum them. [17]
- Sum of {all current month's ADU squared} [18]

From the data above modified ADU mean factors and standard deviation factors are determined for each range as follows:

Modified Mean Factor:

Sum of {last month ADU times current month ADU} divided by the sum of {all last month's ADU squared} [19]

Modified Standard Deviation Factor:

Step 1: (Sum of {all current month's ADU squared} minus (Mean squared times sum of {all last month's ADU squared})) divided by (Total Meters minus 1). [20]

Step 2: Take square root of Step 1

1.5.2 Calculate high and low range factors.

Calculate high and low range factors (HRF and LRF) for each of the 3 usage ranges within a geographic area. The mean is used to calculate estimated reads, and the high and low range factors are used in this validation check. 2.8 and 3.5 are used in the below example to represent the range deviation factor and will allow for an appropriate meter read error rate. This factor can be changed to control the error rate.

High Range Factor Formula:

$$\text{HRF} = 1 + \{(2.8 \times \text{Modified Standard Deviation} \times \text{Number of meters}) / (\text{Sum of Current month's ADU})\}$$
 [21]

Low Range Factor Formula:

$$\text{LRF} = 1 - \{(3.5 \times \text{Modified Standard Deviation} \times \text{Number of meters}) / (\text{Sum of Current month's ADU})\}$$
 [22]

1.6 As each meter is read, perform the following using the values calculated from the previous meter reading days' data.

1.6.1 Determine the usage from the preceding billing month and the preceding billing reading for the customer and site. [23]

1.6.2 Calculate low limit for this month's usage by multiplying the preceding month's usage by the low range factor determined above. [24]

1.6.3 Calculate high limit for this month's usage by multiplying the preceding month's usage by the high range factor determined above. [25]

1.6.4 If the current usage is between the low and high limit calculated in the previous two steps, the data passes the High/Low check. [26]

2. Estimating Usage

2.1. Method 2 - Based on historical usage and similar customers

2.1.1 For the residential meter population (i.e., same geographic area and customer class), utilize the following determinants as determined in 1.:

- ADU Low Range Factor (1.4.4)
 - ADU High Range Factor (1.4.4)
 - Low Range Modified Mean Factor (1.5.1)
 - Medium Range Modified Mean Factor (1.5.1)
 - High Range Modified Mean Factor (1.5.1)
- 2.1.2. Calculate the ADU from last month's billing period for that customer. [27]
- 2.1.3. Calculate the modified ADU for a specific meter by multiplying last month's ADU (from step 2.1.2) by yesterday's medium range modified mean factor (above) for that geographical area. [28]
- 2.1.4. Determine if the modified ADU is in yesterday's low, medium, or high range. [29]
- If the modified ADU is less than the ADU low range factor, yesterday's low range modified mean factor is used to calculate estimated ADU in the succeeding steps.
 - If the modified ADU is equal to or greater than ADU low range factor but less than the ADU high range factor, yesterday's medium range modified mean factor is used to calculate estimated ADU in the succeeding steps.
 - If the modified ADU is greater than or equal to the ADU high range factor, yesterday's high range modified mean factor is used to calculate estimated ADU in the succeeding steps.
- 2.1.5. Multiply the prior ADU by the modified mean factor determined in 2.1.4. This becomes the new estimated ADU. [30]
- 2.1.6. Continue with steps 2.1.2, and 2.1.3 using the estimated ADU calculated in the preceding step.

Spreadsheet Calculations:

Meter Number	Current Usage	Current ADU	Last Month Usage	Last Month ADU	Meter Reading	Current ADU * Last Month ADU	Current ADU Squared	Last Month ADU Squared	Range Grouping
1	125	4.17	135	4.50	3731	18.75	17.36	20.25	Low
2	275	9.17	250	8.33	7475	76.39	84.03	69.44	High
3	114	3.80	142	4.73	3697	17.99	14.44	22.40	Low
4	178	5.93	165	5.50	4888	32.63	35.20	30.25	Medium
5	254	8.47	260	8.67	7358	73.38	71.68	75.11	High
6	299	9.97	189	6.30	6835	62.79	99.33	39.69	High
7	178	5.93	190	6.33	5278	37.58	35.20	40.11	Medium
8	158	5.27	136	4.53	4176	23.88	27.74	20.55	Medium
9	165	5.50	140	4.67	4329	25.67	30.25	21.78	Medium
10	235	7.83	255	8.50	7033	66.58	61.36	72.25	High
11	218	7.27	235	7.83	6500	56.92	52.80	61.36	High
12	110	3.67	119	3.97	3286	14.54	13.44	15.73	Low
13	98	3.27	105	3.50	2912	11.43	10.67	12.25	Low
14	85	2.83	129	4.30	3117	12.18	8.03	18.49	Low
15	169	5.63	110	3.67	3913	20.66	31.73	13.44	Medium
16	200	6.67	168	5.60	5221	37.33	44.44	31.36	High
17	147	4.90	178	5.93	4688	29.07	24.01	35.20	Low
18	165	5.50	201	6.70	5281	36.85	30.25	44.89	Medium
19	180	6.00	135	4.50	4446	27	36.00	20.25	Medium
Sum		111.77		108.07		681.63	727.99	664.82	

Assume yesterday's ADU low range factor was 4.95 and the ADU high range factor was 6.4.

Mean (8) 5.88
 Std Dev (9) 1.98
 ADU Low Range Factor (10) 5.03
 ADU High Range Factor (11) 6.73

Ranges	Low	High
Low	0	5.03
Medium	5.03	6.73
High	6.73	or higher

(13) Meters	(15) Curr ADU
Low	6 22.63
Medium	7 39.77
High	6 49.37

(14) Last mo ADU
26.93
35.90
45.23

(16) Curr * Last Mo ADU	(18) Curr Mo sqrd	(17) Last Mo ADU Sqrd
103.97	87.95	124.33
204.26	226.38	191.27
373.40	413.66	349.22

(19) Modified Mean	(20) Mod Std Deviation
Low 0.84	0.45
Medium 1.07	1.17
High 1.07	1.70

(22) Low Range Factor	(21) High Range Factor
0.58	1.33
0.28	1.58
0.28	1.58

Example validation routine for meter read the following day using the determinants calculated above:

Customer's Last Month's Usage = 200 kWh (23) ADU = 6.67 Customer's usage falls in Medium Range

High Range Value: 200 kWh X 1.58 = 316 (25)
 Low Range Value: 200 kWh X 0.28 = 56 (24)

Usage falling between 56 and 316 is acceptable. Usage outside of this range fails the high/low usage check. (26)

Example estimation routine for meter read the following day using the determinants calculated above:

Customer's Previous Usage = 200 kWh (27) ADU = 6.67

Modified ADU = 6.67 X 1.07 (Medium Range Modified Mean Factor)
 = 7.14 Modified ADU (28)

Determine where 7.14 is grouped according to the ADU low and high range factors (5.03 & 6.73 respectively)
 7.14 > 6.73, therefore, the high range modified mean factor of 1.07 is used. (29)

ADU Estimated usage = last month's ADU (6.67) X 1.07 = 7.14, rounded to 7
 Total usage = ADU Estimated usage X number of days in the billing period. (30)

APPENDIX 9 – UBP METERING GLOSSARY

*Note: This glossary does not include terms from the non-metering UBP Volume One document. Please refer to the website for that glossary.

Acceptable Quality Level (AQL) - Maximum percentage of non-conforming meters allowed in the meter population or group of meters.

Account Level - The most discrete level of customer load aggregation for which a bill is produced. It may represent one or more metered or unmetered Service Delivery Points belonging to one Customer.

Aggregation - The treatment of multiple customer loads (meters) as a single user.

Aggregator - An entity that combines customers into a buying group for the purchase of a commodity service.

Automatic Meter Reading (AMR) - A communication process that facilitates the remote interrogation of a meter.

Average Daily Usage (ADU) - The consumption used for billing divided by the number of days in that billing period.

Best Practices - Set of procedures, instructions and standards that describe the best process to achieve and maintain a given objective.

Billing Date - Date on which the Billing Party produces the bill.

Billing Party - The designated agent who processes and presents a bill to the consumer.

Bundled Metering - Metering services typically provided by the Utility.

Business Days - Monday through Friday, excluding holidays.

Bypass - Device used to shunt the current around a meter. Allows the meter to be serviced without dropping the load.

Caduceus Symbol - Representation of a staff with two entwined snakes and two wings at the top.

Central Monitoring Entity - The entity that tracks all information needed for control of all metered and unmetered Service Delivery Points in a given geographic area.

Competitive Metering - An environment where Customers/Energy Suppliers are able to choose the providers of metering services from among a number of suppliers.

Consumption Data - Meter usage data that represents the energy consumption (e.g. kWh) for a customer for a given time period.

Cramming – The process of placing charges for unordered and unwanted services on the Customer's electricity bill.

Customer Owned Meter - Refers to a meter that is owned by a retail customer.

Default Metering Service Provider – An entity that assumes the role of providing metering services to a customer, when no other source of these services is available.

Demand – The rate of energy consumption measured over a predefined period of time (e.g. kW).

Demand Test - Tests the accuracy of the demand measuring device.

Distribution - The delivery of electricity to retail customers .

Distribution Charge - A charge for using the Utility distribution system to deliver energy to the customer. The distribution charge is a regulated tariff.

Distribution Tariff - A regulator-approved document setting out the terms, conditions, and prices for distribution service from a Utility.

Electric Cooperative - A not-for-profit electric Utility, which is cooperatively, owned by its members, generally either a distribution cooperative or generation and transmission cooperative.

Electronic Data Interchange (EDI) - The computer-application-to-computer-application exchange of business information in a standard format. In the context of this report, EDI refers to use of the ANSI X12 standards.

End Point - Refers to the end time of an interval when providing meter usage data for billing or estimating.

Energy Supplier – Any entity that sells energy to retail customers using the transmission and/or distribution system of a Utility.

Estimated – Meter usage data that has been calculated based on standard estimation rules because the raw data was unavailable or invalid.

Greenwich Mean Time (GMT) - The mean time at the meridian of Greenwich, England.

Grid - A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points.

Heavy Load - Any load over 10% of the test ampere rating of a meter.

High Range Factor (HRF) - The value that the “average daily use” must be below to validate the consumption data. The “high” threshold on a High/Low check.

Kilowatt (kW) - Unit of electrical demand.

Kilowatt-hour (kWh) - The basic unit of electrical energy use.

kyz - A meter output that produces a pulse proportional to the energy usage.

Life Support Seal - Seal for equipment supporting a customer with a life support device.

Light and Full Load Test or Customer Load Test - Measures meter accuracy at various load conditions.

Low Range Factor (LRF) - The value that the “average daily use” must exceed to validate energy consumption. The “low” threshold on a High/Low check.

Meter - A device for measuring and totaling the variable consumption and/or demand of energy.

Meter Data Service Provider (MDSP) - An entity having responsibility for the processing of meter usage data. MDSP functions include, but are not limited to, translation, validation, estimation and provision of metered usage data.

Meter Identifier (ID) - A number or set of alpha-numeric characters used to uniquely identify a meter.

Meter Reading Service Provider (MRSP) - Entity that provides for the transfer of electric meter reading data to a host system for the purposes of determining meter usage data. Service can be performed manually or via an Automatic Meter Reading (AMR) system.

Meter Service Provider (MSP) - Entity that provides the physical electric meter services, such as, installation, removal and maintenance of the meter.

Meter Services Agreement (MSA) - A contract between two or more entities for the provision of metering service functions.

Metering Circuit - The wiring to connect the meter so that it correctly measures electrical consumption.

Metering Entity - The company or agent responsible for the installation, removal, exchange, reading, and maintenance of the data or physical metering assets.

Metering Provider - See Metering Entity

Metering System - The physical equipment at a customer's site that includes the following components; the meter, the customer's meter fitting, instrument transformers (i.e., VT's and CT's), internal wiring, and communication links.

Monthly Usage Data - Cumulative monthly energy consumption, demand, and Time-of-Use (TOU) consumption and/or demands accumulated over a monthly cycle.

Power Factor - Ratio of active power to apparent power.

Pulse - A contact closure that represents a specific quantity of energy. Pulses are typically used as inputs to load control or data logging equipment.

Rated Voltage - The range of voltages at which the meter operates.

Raw Meter Data – Meter data that has not gone through the validating, editing and estimating (VEE) process.

Reframing - Resending of interval data for a corrected time period.

Retail Access - The ability of a retail customer to purchase commodity electricity from a competitive Supplier rather than from the local distribution utility.

Revenue and Billing Determinants - Those elements of meter usage data that are directly used in the calculation of a bill.

Service Delivery Point - The point at which energy is transferred to the Customer's wiring system from the Distribution system of the Utility.

Service Delivery Point Identifier - A unique identifier representing the physical point where energy passes from the Utility Distribution system to the Customer. This identifier is permanent and doesn't change with a change in

Customer, Energy Supplier, Metering Provider, or a physical change in metering.

Service Entry Equipment - The pans, sockets and cabinets required for installation and connection of a meter to the distribution system and the customer's load.

Site ID - An identifier of a customer's premise.

Slamming – The act of changing a Customer's chosen Energy Supplier without the Customer's consent.

Time-of-Use (TOU) Rates - The pricing of electricity based on the actual or estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter).

Totalization - The summation of energy demand and consumption for two or more meters.

Traceability - Process by which an assigned value of measurement is compared, directly or indirectly, through a series of calibrations (or comparisons) to the value established by the National Institute of Standards and Technology (NIST) as the standard value.

Unaccounted-for-Energy (UFE) - The difference between the energy input and known system load.

Unbundled Electricity Metering Services - The unbundling of metering into discrete functions such as meter ownership, maintenance, reading, and data services.

Uniform Business Practices (UBP) - Set of business operating practices that describe recommended "best practices" for competitive retail electric markets.

Utility Industry Group (UIG) - A utility industry action group that represents members to ASC X12. UIG develops, promotes, and establishes conventions for the use of EDI standards, guidelines, and tools in the utility industry. Membership includes utilities, customers, suppliers, service providers, and liaisons to other organizations.

Utility Service Territory - The regulated service area served by a Utility. Also referred to as service area.

Valid Data – Meter usage data that has gone through all required validation checks and has passed or been verified.

Validating, Editing, and Estimating (VEE) - Set of techniques used to verify, modify and estimate raw data from an energy customer.

Verified Data - Data that failed at least one of the required validation checks but was determined to represent actual usage.

Voltage Test - Measures service voltage and detects presence of short circuit or other hazardous condition. At minimum the voltage test measures the secondary voltage between the line phases and between the line and ground.

NOTATIONS AND ACRONYMS (used in UBP/Glossary)

AQL - Acceptable Quality Level
AMR - Automatic Meter Reading
ADU - Average Daily Use
ARA - Applicable Regulatory Authority
EEI - Edison Electric Institute
EDI - Electronic Data Interchange
FERC - Federal Energy Regulatory Commission
GMT - Greenwich Mean Time
HRF - High Range Factor
LRF - Low Range Factor
MDSP - Meter Data Service Provider
MRSP - Meter Reading Service Provider
MSP - Meter Service Provider
MSA - Meter Services Agreement
UFE - Unaccounted-for-Energy
UBP - Uniform Business Practices
UDC - Utility Distribution Company
UIG - Utility Industry Group
VEE - Validating, Editing, and Estimating

APPENDIX 10 – METER PRODUCT/EQUIPMENT TYPE SELF CERTIFICATION FORM

Meter Product/Equipment Type Self Certification Form

PLEASE PRINT OR TYPE

Name of Manufacturer:	
-----------------------	--

Current Business Address:

--

Street Address

--	--	--

City

State

Zip Code

Contact Individual:	
---------------------	--

Contact's Telephone Number:	
-----------------------------	--

Contact's Fax Number:	
-----------------------	--

Contact's E-Mail Address	
--------------------------	--

Please attach a complete list of the meter products certified as compliant with the Certification Testing Requirements. The identifying information provided will be posted **verbatim** on the ARA website. The attached list must be provided in the format shown below:

Manufacturer Name	Model Number

(use as many rows as necessary)

**Meter Product/Equipment Type
Self Certification Form**

This self-certification document must be verified by an officer or authorized employee of the manufacturer by completing the following declaration:

DECLARATION

I, (print name and title) _____,

_____ hereby certify that I am empowered to act on behalf of

_____ (meter

manufacturer's company name) and to submit this self-certification document

on its behalf. I declare under penalty of perjury under the laws of the State of

that the above statements are true and correct, and that if any documents are

furnished in connection with this self-certification document, that those

documents are true and correct copies.

Dated _____,
(date)

At _____.
(place of execution)

Signature: _____

Note: The verification must be made by an affidavit sworn or affirmed before a notary public.

Return this document with required attachments to:

**Meter Product Certification Staff
Public Utilities Commission of ARA
1150 E. ARA Street
City, ARA 99999-9999**