Standards for Uniform Business Rules

Version 1.1

COALITION FOR UNIFORM BUSINESS RULES
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TABLE OF CONTENTS

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MISSION STATEMENT

Retail electricity and natural gas competition offers consumers innovative services and products stimulated by an open market. To reap the benefits of an open market, regulators and legislators must reshape markets fairly while promoting competition. One significant barrier to competition is the lack of uniform business rules from state-to-state. The Coalition for Uniform Business Rules (CUBR) was formed to address this barrier. Competitive service providers participating in several markets throughout the country have unique insights on the business rules that encourage fair and innovative restructuring processes. CUBR consists of representatives from natural gas and electricity marketers, utilities, meter service providers, meter data management agents, billing and collection companies, software vendors, and other mid and back-office service providers.

In September of 1999, CUBR released a consensus document that describes minimum uniform business rules. Industry participants who have "road tested" competitive environments across the nation and who have identified best business practices in the electricity and natural gas industry drafted consensus-supported uniform business rules. The CUBR document focuses on the following ten priority issues: (1) Supplier Licensing; (2) Customer Information; (3) Enrollment and Customer Switching; (4) Creditworthiness; (5) Billing and Payments; (6) Electric Metering; (7) Electric and Natural Gas Operations; (8) Supplier Tariff and Agreements; (9) Performance Standards and Incentives; and (10) Utility-Supplier Dispute Resolution Process. As part of its mission, CUBR also will release standard electronic transaction (SET) implementation guides and data dictionaries for the business rules by the end of 1999.

CUBR's proposal will do more than promote competition and facilitate interactions between suppliers and utilities, it will directly benefit the consumer. Uniform business rules lower costs for all market participants, ease market entry, enable the free movement of capital, goods, and services, and offer more information for all market participants. As a result, consumers have more choices and better opportunities to recognize the value of a competitive marketplace. Competitors will quickly enter advantageous markets, stimulating the growth of innovative products and services to keep their customers happy. CUBR will work with all market participants and facilitators to promote and establish the principles of the CUBR document as a standard for all open, competitive electricity and natural gas markets throughout the United States.

This document is the Mission Statement of the CUBR Uniform Business Rules Document, Version 1.1, Dated September 1999. The CUBR Document should be considered in its entirety. See Appendix for disclaimers.

INTRODUCTION

In April 1999, the Coalition for Uniform Business Rules (CUBR) was formed to address the areas where uniform business rules should be adopted to facilitate the development of competitive retail natural gas and electricity market. CUBR consists of a diverse cross section of the electricity and natural gas industry, representing natural gas and electricity marketers, utilities, meter service providers, meter data management agents, billing and collections companies, software vendors, and other mid and back-office service providers.

The CUBR identified the following ten high priority issues on which to develop a consensus document outlining uniform business rules for the retail electric and natural gas markets: (1) Supplier Licensing; (2) Customer Information; (3) Enrollment and Customer Switching; (4) Creditworthiness; (5) Billing and Payments; (6) Electric Metering; (7) Electric and Natural Gas Operations; (8) Supplier Tariff and Agreements; (9) Performance Standards and Incentives; and (10) Utility-Supplier Dispute Resolution Process. CUBR expects to release standard electronic transaction (SET) implementation guides and data dictionaries for the business rules by the end of 1999.

The uniform business rules are based on best business practices and the CUBR participants' collective experience with restructuring throughout the country. In its effort to develop "best practices", CUBR based its recommended uniform business rules on currently existing business rules implemented in the states for electric and/or gas restructuring and by FERC for the wholesale industry. The models relied on for the base documents include California, Nevada, New York, Ohio, Pennsylvania, Massachusetts, New Jersey, Gas Industry Standards Board (GISB), and Utility Industry Group (UIG). The base documents have been modified to reflect the experiences of the CUBR Members when implementing retail choice in the various states under different business rules. Developed through a consensus process, the CUBR-proposed uniform business rules are fair, efficient guidelines, which balance the interests of all market participants while enhancing retail competition in the natural gas and electricity markets. The document represents a good faith effort by the participants to develop mutually acceptable language through consensus and compromise.

Uniform business processes and standard electronic transactions, as outlined herein, would significantly reduce the barriers to a competitive market created by different business practices and data formats developed and implemented at the state level. Although necessary for the initial transition to a competitive market, non-uniform business practices hinder the evolution of a natural gas and electricity retail market on a national scale. The primary beneficiary of uniform business rules is the customer, since uniform practices lower the barriers to entry for competitive service providers and allow competitive suppliers to offer increased savings. By eliminating the duplicative

efforts necessary to comply with varying state-by-state regulatory requirements, uniform practices also help clear the path for the market to reduce prices and create new innovative products, services, and market entrants.

Another important benefit of uniform business processes is a significant reduction in the competitive market's transition time. Experience in other previously regulated industries indicates that the transition to a competitive market is likely to be slow and complicated; however, a successful, common sense streamlining that expedites the transition period, such as adopting uniform practices, will benefit all market participants by reducing costs and transition time.

In addition to facilitating the transition period and lowering costs for all market participants, other benefits of uniform business rules include: improved communications and expectations between market participants; ease of market entry; the free movement of capital, goods, and services; and additional resources for the development of new and innovative products and services.

The following sections illustrate consensus-developed business rules for both electricity and natural gas retail markets that are efficient and fair to all market participants. Most of the sections apply to both the electricity and natural gas retail markets since common business rules may govern the interaction between suppliers and utilities, regardless of the commodity. However, the metering section applies only to electric meters since the retail natural gas industry has not yet thoroughly explored nor implemented rules to govern competitive metering for natural gas. Second, there are two different subsections relating to operations. The electricity-specific operations section includes retail settlements, forecasting, losses, and load profiles. The gas-specific operations section discusses the interplay between the retail and wholesale aspects of the natural gas market.

Finally, assumptions specific to an issue are identified at the beginning of each section; however, there are certain underlying assumptions made within this document. For instance, the document does not address stranded costs; back-out rates; fees; which services, such as billing and metering, should be competitive; or if, and to what extent, there should be unbundling. To the extent the legislature and/or the regulatory authority determines to open the retail electricity and/or natural gas markets, the CUBR Document details recommended, uniform operating rules.

I. LICENSING

Currently, each state has different laws regarding whether electric and/or natural gas Suppliers must be licensed to provide service. Furthermore, those states which do require Suppliers to be licensed have varying thresholds for licensing based on the size of the customers served. For instance, many states do not impose licensing requirements on Suppliers selling natural gas to large customers. Similarly, there are small customer pilot programs in various states that allow Suppliers to participate without being licensed. However, other states require all Suppliers to be licensed, while other states require Suppliers serving residential and/or small commercial customers to be licensed.

A. APPLICABILITY

1. To the extent required by the applicable regulatory authority, the following licensing process applies to electric and natural gas Suppliers.

2. Where applicable, a Supplier offering both electric and natural gas should be able to apply for one license covering both services.

3. If a license is required, no Supplier shall enroll customers without having obtained a license from the applicable regulatory authority.

B. APPLICATION PROCESS

1. Applications shall be made on forms provided by the applicable regulatory authority. The application form should be readily available and posted in a downloadable format on the applicable regulatory authority's website. An application shall be verified by an oath or affirmation to the best of the Applicant's knowledge, in accordance with the applicable legal authority requirements.

2. The applicable regulatory authority shall maintain and update a list of all Applicants and the Applicants' status on its website.

3. The applicable regulatory authority shall process all completed applications and notify Applicants of its determination within thirty (30) days of the receipt of the application. If the applicable regulatory authority has not completed the review process within the 30-day period, the applicable regulatory authority shall issue the Applicant an interim Supplier license, valid for ninety (90)

days. The Supplier will be granted a license automatically following the 90-day period, unless the applicable regulatory authority explicitly denies the application.

4. If additional information is required from the Applicant, the 30-day processing period begins when the additional information has been received by the applicable regulatory authority. The applicable regulatory authority will notify the Applicant within two weeks of receipt of the application if, and what, additional information is required. If a deficiency is found in the Applicant's application, the Applicant will have two weeks upon receipt of written notice to provide notice of intent to cure the deficiency.

5. The knowing and/or intentional making of false statement(s) may be grounds for denying the Application or, if later discovered, for revoking any authority granted pursuant to the Application. The Application is subject to the applicable regulations and statutes relating to perjury and falsification of official matters.

C. APPLICATION REQUIREMENTS

1. The Application should include the following information:

a. Identity of the Applicant:

(1) the Applicant's name, address, telephone number, Applicant's contact's electronic mail (e-mail) address, website address (if applicable), and facsimile number;

(2) any predecessor(s) of the Applicant and other names under which the Applicant has operated within the preceding five (5) years, including name, address, and telephone number; and

(3) the name(s) under which the Applicant markets services regulated by the applicable regulatory authority in the state.

b. A description of the business structure, including incorporation information, a list of corporate officers, a copy of the business license or certificate of authority to do business in the state (if applicable), state sales tax identification number (if applicable), and federal tax identification number.

c. Names and addresses of the affiliate(s) which are jurisdictional public utilities, intrastate pipelines, interstate pipelines, municipal utilities, or cooperatives operating within the state.

d. Contact Information:

(1) name, address, telephone number, e-mail address, and facsimile number of employee designated to receive and respond to applicable regulatory authority requests and who will notify the applicable regulatory authority of any changes to the information provided in the Application;

(2) title, department, address, telephone number, and facsimile number designated for emergencies;

(3) title, department, address, telephone number, e-mail address (if applicable), and facsimile number for the applicable regulatory authority to contact to address customer complaints; and

(4) Applicant's toll-free customer service telephone number for inquiries.

e. Agent of Process upon whom process may be served and Agent of Process' address, telephone number, and facsimile number.

f. A statement whether the Applicant or its agent has a Federal Energy Regulatory Commission (FERC) Power Marketing License. If applicable, the Power Marketing License number.

2. The Applicant shall provide the following information, if applicable, to demonstrate financial fitness:

a. Actual (or proposed) organizational structure of the Applicant.

b. Applicant's publicly available balance sheet and income statement for the most recent fiscal year. Published financial information such as 10Ks and 10Qs will be deemed to satisfy this requirement. If the Applicant does not have published financial information such as 10Ks and 10Qs, the Applicant's parent's 10K or 10Q will satisfy this requirement.

c. Evidence of Applicant's credit rating. Applicant may satisfy this requirement by providing information from Dun and Bradstreet credit reports, Robert Morris and Associates financial forms, or other independent financial service reports.

d. At the Applicant's discretion, published parent company financial and credit information.

e. Annual Report, if available.

f. At the Applicant's discretion, other financial information. For instance, the Applicant may furnish other creditworthiness/financial information used to demonstrate financial fitness in other states or in other segments of the energy industry.

3. The Applicant shall provide the following information to demonstrate technical fitness and its ability to comply with the applicable regulatory authority's requirements.

a. Documentation of the Applicant's or its agent's membership in regional reliability councils shall be submitted if applicable to the scope and nature of the Applicant's proposed services.

b. Whether the Applicant is currently licensed or certified as a Supplier in other states. If the Applicant is not, then the Applicant must demonstrate its ability to comply with the applicable regulatory authority's applicable requirements concerning customer billing, customer education, billing and terms of service, and customer information. This evidence may include prior regulatory experience of Applicant, prior business experience in energy or other service-oriented industries, staffing and staff training commitments, agreements, arrangements and contracts for customer education and information service, customer satisfaction survey results, and government agency reports.

4. The Applicant must state whether the Applicant, a predecessor, or an officer or director identified in the Application has been convicted or found liable for fraud or convicted of a felony within the last five (5) years.

5. The Applicant must provide a bond, financial guarantee, letter of credit, or proof of bonding to the applicable regulatory authority in a maximum amount of $100,000. It is at the Applicant's discretion to determine what form of bonding to use, *i.e.*, a bond, a financial guarantee (if the guarantor has a long-term

minimum rating of "BBB-" from S&P's, “Baa3” from Moody's, or “BBB-“ from Fitch), or a letter of credit. The purpose of the bond is to ensure the payment of fines and/or penalties levied by the applicable regulatory authority.

a. The bond or security shall include:

(1) the applicable regulatory authority and/or the state as the sole beneficiaries;

(2) the purpose of the bond, which is to ensure the payment of fines and/or penalties levied by the applicable regulatory authority;

(3) a statement that the security shall be interpreted under the appropriate state law, or in the alternative, no choice of law is specified;

b. The applicable regulatory authority should provide the exact language that should appear on the bond or security.

c. The Applicant may file for a modification to the $100,000 and furnish a copy of a bond, financial guarantee, letter of credit, or proof of bonding to the applicable regulatory authority for a lesser amount. The Applicant is required to provide information supporting an amount less than $100,000. The Applicant may request the use of a security other than a bond, financial guarantee, or letter of credit. The Application shall include specific information about the Applicant’s need to use a security other than a bond, financial guarantee, or letter of credit; and shall provide the name, business address, the nature of the business of the entity issuing the security, and if available, the financial rating of the entity. The Applicant shall demonstrate that the financial protection afforded by the security is equivalent to that of a bond, financial guarantee, or letter of credit.

6. The Applicant must agree to conform to any uniform standards of conduct and disclosure as set forth by the applicable regulatory authorities.

D. CONDITIONS FOR MAINTAINING A LICENSE IN GOOD STANDING

1. If there are any material changes to the Applicant’s information during the pendency of the application or if the information changes while the Supplier is operating within the state, the Applicant must inform the applicable regulatory authority of any material changes within thirty (30) days.

2. The license is a permanent license to serve customers in the state. The license is valid until revoked by the applicable regulatory authority after due process guarantees are afforded or until the Supplier withdraws from service in the state.

3. If a deficiency is found in the Supplier's maintenance of its license in good standing, the Supplier will have thirty (30) days upon receipt of written notice to cure the deficiency or to file a request for an extension to cure the deficiency.

E. CONFIDENTIALITY

1. The entire Application is deemed confidential and not subject to public disclosure, unless otherwise required to be disclosed pursuant to other statutory provisions. If information must be disclosed, then the confidentiality of the information shall be maintained consistent with the applicable regulatory authority's rules and regulations pertaining to confidentiality.

II. CUSTOMER INFORMATION

To facilitate retail access, the Utilities (or functional equivalents) must provide account-specific information to the Suppliers at two stages -- pre-enrollment and enrollment. While the process for releasing Customer Information at the enrollment stage is identical for all customers, there are two distinct processes depending on the customer class for releasing account-specific information at the pre-enrollment stage, which includes the period before the market opens for retail access. In addition to requiring Suppliers to comply with the applicable consumer protection laws, the following describes the process for releasing Customer Information to Suppliers, as well as the specific information that should be released.

PRE-ENROLLMENT (INCLUDING PRE-MARKET OPENING)

A. RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER INFORMATION

The release of customer information for residential and small commercial customer classes is important to all stakeholders. Verification of information received from customers against correct data reduces errors and costs for the Utility (or functional equivalent) and the Supplier. In addition, there are fewer customer complaints generated from the use of incorrect or outdated information during the enrollment transactions. Experience has shown the release of such information reduces barriers to entry and establishes a level playing field that promotes competition and choice. The use of verified, correct information also reduces the need to delay the customer's enrollment by rechecking data, as well as avoiding a situation where the customer is dropped due to incorrect data. Access to current customer information streamlines customer interactions by providing the customer the option to enroll with a Supplier of their choice using the most convenient information available since the Supplier can cross-reference and verify against current data. Utility customer service costs are reduced by not having to support the need to verify or provide account numbers to customers.

1. Unless specifically restricted by a customer or its agent, *via* the applicable regulatory authority-approved mechanism, the following information shall be released to authorized Suppliers for all residential and small commercial customers:

a. Name;

b. Billing address;

c. Service address;

d. Utility account number;[1]

e. Service Delivery Point Identifier (if available);

f. Telephone number;

g. Rate class and sub-class (if applicable);

h. Rider (if applicable);

i. Load Profile reference category;

j. Universal Identifier (if available);

k. Meter type;

l. Interval meter data indicator;

m. Budget bill indicator;

n. Meter read date or schedule;

o. The most recent thirteen (13) months of historical usage data (data used for billing determinants, including, if applicable, monthly metered usage, usage (kilowatts or dekatherms), energy (kilowatthours), and maximum daily quantity (MDQ)) and metered interval usage, when available; and

p. Any other pertinent customer information, *e.g.*, congestion zones or gas pools.

2. The Utility (or functional equivalent), in conjunction with the applicable regulatory authority-approved education materials, shall issue a post-card, inclusive of two (2) negative check-off boxes, to all residential and small commercial customers, by which a customer may restrict certain information about its account. The customer shall be able to restrict the release of its telephone number or the release of any account-specific information by affirmatively checking one of the aforementioned boxes.

[1] If the Utility account number changes, the Utility (or functional equivalent) is responsible for maintaining the old Utility account number for ninety (90) days.

Example of a negative check-off box:

_____ I do NOT wish to have my telephone number released to authorized Suppliers.

_____ I do NOT wish to have any of my account-specific information released to authorized Suppliers.

3. Any restrictions of the information above may occur only as a result of individual customer action. The post-cards should advise customers that if they do not allow their information to be released, the offers from Suppliers may be limited. Proof of any restrictions must be retained by the Utility (or functional equivalent) in accordance with the applicable regulatory authority-approved mechanisms.

4. Residential and small commercial customer information shall be provided *via* an eligible customer information list, updated by the Utility (or functional equivalent) on a weekly basis to reflect any changes in customer information. The eligible customer information list shall be available only to authorized Suppliers. The list shall be provided on the Utility's (or functional equivalent's) "secured" website or other electronic means mutually agreeable between the individual Supplier and Utility.

5. The Supplier shall be provided access to load profile information for all classes and subclasses of residential and small commercial customers.

B. LARGE COMMERCIAL AND INDUSTRIAL CUSTOMER INFORMATION

1. The following information shall be released to Suppliers for large commercial and industrial customers upon proper customer authorization from the customer or the customer's agent:

a. Name;

b. Billing address;

c. Service address;

d. Utility account number;[2]

[2] If the Utility account number changes, the Utility (or functional equivalent) is responsible for maintaining the old Utility account number for ninety (90) days.

e. Service Delivery Point Identifier (if available);

f. Telephone number;

g. Rate class and sub-class (if applicable);

h. Rider (if applicable);

i. Load Profile reference category;

j. Universal Identifier (if available);

k. Meter type;

l. Interval meter data indicator;

m. Budget bill indicator;

n. Meter read date or schedule;

o. The most recent thirteen (13) months of historical usage (data used for billing determinants, including, if applicable, monthly metered usage, usage (kilowatts or dekatherms), energy (kilowatthours), and maximum daily quantity (MDQ)) and metered interval usage, when available; and

p. Any other pertinent customer information, *e.g.*, congestion zones or gas pools.

2. Customer authorization may be provided in written, electronic, or verbal form as long as the proof of authorization is properly retained by the Supplier for a period of two (2) years.

3. The request for customer information shall be submitted to the Utility (or functional equivalent) by the Supplier *via* the appropriate SET protocol, if it has been developed, tested and implemented. As stated above, the Supplier must have customer authorization for certain customer classes to request account-specific information and the level of customer authorization would need to be indicated in the request. If the SET protocol is not available, then the request should be submitted by the Supplier with the appropriate customer authorization to the Utility (or functional equivalent) *via* the standard Customer Information Release Form. See Exhibit 1 for a Sample Customer Information Release Form. These provisions do not preclude the customer from requesting the information directly from the Utility.

4. The above-listed information shall be provided by the Utility (or functional equivalent) to the Supplier within one (1) business day of the Supplier's request, *via* the appropriate SET protocol, if it has been developed, tested and implemented. As an interim

measure, if the SET is not yet available, then the information shall be provided electronically *via* a standardized comma separated value (CSV) file.

5. Large commercial and industrial customer information shall be provided to Suppliers on an individual meter basis. The Supplier shall be provided access to load profile information for all classes and subclasses of large commercial and industrial customers.

ENROLLMENT

A. CUSTOMER INFORMATION

1. Upon acceptance of the Enrollment Request, the Utility (or functional equivalent) shall provide to the Supplier the following account-specific information for each customer:

a. Name;

b. Billing address;

c. Service address;

d. Utility account number;[3]

e. Service Delivery Point Identifier (if available);

f. Telephone number;

g. Rate class and sub-class (if applicable);

h. Rider (if applicable);

i. Load Profile reference category;

j. Universal Identifier (if available);

k. Meter type;

l. Meter read date or schedule;

m. Interval meter read indicator;

n. Budget bill indicator;

[3] If the Utility account number changes, the Utility (or functional equivalent) is responsible for maintaining the old Utility account number for ninety (90) days.

o. The most recent thirteen (13) months of historical usage (data used for billing determinants, including, if applicable, monthly metered usage, usage (kilowatts or dekatherms), energy (kilowatthours), and Maximum Daily Quantity (MDQ)) and metered interval usage, when available; and

p. Any other pertinent customer information, *e.g.*, congestion zones or gas pools.

2. By selecting a Supplier, the customer consents to the release of the applicable account-specific information and pertinent metering and usage information required for billing, settlement and other functions necessary for the Supplier to meet its contractual and regulatory obligations.

3. Account-specific information will be provided *via* the appropriate SET protocol when a validated Enrollment Response is sent to the Supplier. Historical usage shall be provided *via* the appropriate SET protocol within three (3) business days of the acceptance of the valid Enrollment Request. As an interim measure, if the SET is not available, then the information shall be provided electronically *via* a standardized CSV file.

SUPPLIER TO SUPPLIER SWITCH

A. CUSTOMER INFORMATION

1. Until such time that an independent router of information is created to process one-time transactions between Suppliers exchanging account-specific information, upon acceptance of a customer switch, the Utility (or functional equivalent) shall supply the account-specific information and usage history to the "new" Supplier. Account-specific information will be provided *via* the appropriate SET protocol when a validated Enrollment Response is sent to the Supplier.

a. Historical usage shall be provided *via* the appropriate SET protocol within three (3) business days of the acceptance of the valid Enrollment Request. As an interim measure, if the SET is not available, then the information shall be provided electronically *via* a standardized CSV file.

b. The same rules and procedures described above for Pre-Enrollment and Enrollment apply to Supplier to Supplier Switches. If authorization is required for the release of Customer Information, such authorization may be provided in written, electronic, or verbal form provided that proof of authorization is properly retained by the Supplier and that all applicable consumer protection laws and rules are followed.

2. Once an independent router of information is created to process one-time transactions between Suppliers exchanging account-specific information, when authorized by a customer, Customer Information shall be provided to the "new" Supplier by the "old" Supplier. If the entire thirteen (13) months of usage history is not available, the applicable number of months available will be provided.

LARGE COMMERCIAL AND INDUSTRIAL CUSTOMER INFORMATION RELEASE FORM

I hereby give consent for (SUPPLIER NAME) to receive thirteen (13) months of history for my account at the address noted below.

Customer Account Information

List information as it appears on the customer's billing statement:

Account Number: _____

Name: _____

Service Address:

Street: _____

City: _____

State: _____

Zip Code: _____

Provide energy use history for:

____ **Electric** _____ **Gas**

Customer Signature: _____

Date: _____

III. ENROLLMENT AND CUSTOMER SWITCHING

The rules to facilitate customer switching are outlined herein. Three scenarios are addressed: (1) the initial switch from the Utility to a Supplier, (2) a switch from one Supplier to another, and (3) switching from a Supplier to the Provider of Last Resort. A description of how a phase-in approach and how a two step enrollment process may be implemented (*e.g.*, customers mandated to enroll prior to switching to a Supplier) has been purposely excluded since experience suggests that these approaches are not conducive to a competitive market.

A. CUSTOMER ENROLLMENT BY THE SUPPLIER

1. Suppliers may solicit customers subject to the following:

a. The Supplier shall comply with the state's trade practices and/or telemarketing laws and any rules adopted under such statutes.

b. The Supplier shall require any person with whom the Supplier contracts for marketing or solicitation purposes to adhere to the terms of all applicable rules and regulations relating to consumer protections.

c. The Supplier shall take all reasonable steps to assure that persons or entities hired by the Supplier for marketing or solicitation purposes adhere at all times to the terms of all applicable rules and regulations relating to consumer protections.

d. The Supplier shall not state or in any way imply that it has a special relationship with the incumbent Utility or has been given preferential status by the incumbent Utility.

e. The Supplier may enroll customers after having received the customer's authorization *via* any one or more of the following methods:

(1) electronic authorization in accordance with Exhibit 2 – Internet Enrollment;

(2) written authorization bearing a customer's signature (original document signed or a fax copy of signed document);

(3) telephone authorization in accordance with Exhibit 1 - Telephonic Enrollment; or

(4) any additional methods deemed reasonable by the applicable regulatory authority.

f. The use of the enrollment method(s) shall be the choice of the Supplier. The customer shall be able to effectuate an Enrollment with no more than one (1) step.

g. The Utilities (or functional equivalents) shall provide new customers a Utility-specific list of Suppliers, in alphabetic order, during the customer's initial contact with the Utility (or functional equivalent). The Utility-specific list of Suppliers shall be distributed to all non-choosing customers on an annual basis. In addition, the Utility (or functional equivalent) will make the Utility-specific list of Suppliers, in alphabetic order, available to any customer upon request, at any time. The list will be maintained and updated by the applicable regulatory authority.

(1) The Utility-specific list of Suppliers should differentiate between Suppliers actively accepting new residential customers and Suppliers not actively serving or accepting residential customers.

(2) Suppliers shall provide notice in a timely fashion to the applicable regulatory authority of their service status regarding residential customers. The notice shall only be used for the purpose of producing and maintaining the list of Suppliers. This requirement shall not preclude the Supplier from serving classes other than those listed as long as all appropriate licensing requirements are satisfied and the Supplier does not engage in illegal discriminatory behavior in its selection and/or service of customers.

2. Verification. The Supplier shall be responsible for retaining proof of verification of enrollment for all customers for a minimum of two (2) years following the original date of the customer's enrollment with the Supplier. Supplier verification records may be requested by the applicable regulatory authority upon reasonable notice. A customer or another Supplier that believes enrollment has occurred in violation of the solicitation or verification methods may submit a complaint to the applicable regulatory authority within three (3) months of the initial billing by the Supplier.

a. The applicable regulatory authority shall initially conduct an informal investigation of the allegation.

b. The Supplier shall provide the applicable regulatory authority with such records as may be necessary to verify customer authorization. The physical location of the enrollment verification records shall be at the Supplier's discretion, but must be provided

to the applicable regulatory authority within five (5) business days.

3. Customer Notice Letter. The Utility (or functional equivalent) will send a notice letter to the customer within one (1) business day of receiving a valid Enrollment Request from a Supplier. The letter will confirm the customer's Supplier selection and provide the customer with seven (7) calendar days from the date of the letter to notify the Utility (or functional equivalent) if the enrollment is incorrect. The Utility (or functional equivalent) shall retain proof of the notification by the customer that such enrollment is incorrect for two (2) years and shall immediately notify the Supplier *via* the appropriate SET protocol when a customer challenges the enrollment within the seven (7) day period. A pro-forma Utility confirmation letter is attached as Exhibit 2.

4. Enrollment/Switching Schedule. The Supplier shall submit to the Utility (or functional equivalent) an Enrollment Request *via* the appropriate SET protocol which includes the customer name, service address, current Utility account number (or universal identifier, if available), and Service Delivery Point Identifier (if available) for each customer that elects service from the Supplier.

a. The Utility (or functional equivalent) will activate up to one (1) non-challenged Enrollment Request per customer per meter reading cycle. Where multiple Enrollment Requests for the same customer are received during the same meter reading cycle, the first valid Enrollment Request received by the Utility (or functional equivalent), based on the date of the SET transmission, will be processed and all other requests will be rejected. The rejection notice will be sent to each Supplier *via* the appropriate SET protocol.

b. The Utility (or functional equivalent) will respond to the Supplier with a validated Enrollment Response *via* the appropriate SET protocol within one (1) business day of the receipt of the Enrollment Request. The Enrollment Response from the Utility (or functional equivalent) will include the customer switch date.

c. Enrollments shall become effective on the date of the next meter reading, commencing not less than eight (8) business days after the Enrollment Request has been received by the Utility (or functional equivalent) unless the new Supplier agrees to pay for a special meter reading, with the cost of a special meter read stated in the Utility's tariff. Where a special meter reading is made, the new Supplier enrollment is effective on the day the meter reading is obtained.

d. The specific time for switching customers shall be in accordance with the procedures set forth in the Metering Document.

5. Rejection of Enrollment Request. Based on the assumption that a customer eligibility list for residential and small commercial customers is available to Suppliers (on the Utility's (or functional equivalent's) "secured" website or through other electronic means mutually agreeable between the individual Supplier and Utility) as discussed in the Customer Information Document, the Utility (or functional equivalent) shall require only a valid Utility account number (or universal identifier, if available, or Service Delivery Point Identifier, if available) and service address zip code to effectuate the Enrollment Request from a Supplier.[1] If, for any reason, the Supplier's Enrollment Request is not valid, the Utility (or functional equivalent) must send a Rejection of the Enrollment Request *via* the appropriate SET protocol, along with the reason for the rejection. The Utility (or functional equivalent) may reject an Enrollment Request under any of the following circumstances:

a. The Utility account number (or universal identifier, if available, or Service Delivery Point Identifier, if available) and/or the service address zip code provided is incorrect, incomplete, or inactive. If any other fields in the Enrollment Request contain errors, the Utility (or functional equivalent) shall process the enrollment and send the contested information as documented in its system to the Supplier within one (1) business day.

b. The Supplier is not in compliance with the prerequisites for providing service in the specified territory.

c. The customer does not have a physical connection or lacks other equipment necessary to enable the Utility to provide necessary service.

d. A valid Enrollment Request has been received and is pending.

6. Seamless Move. Customers should be able to seamlessly move Supplier service if their physical service location changes. This should not be impeded by moves within a Utility service territory, across Utility territorial borders, or across state borders. The ability to seamlessly move only should be limited by the availability of access to competitive supply in the different jurisdictions and the Supplier being in compliance with the prerequisites to provide service in the specified territory.

a. If a customer moves within the territorial boundaries of a single Utility, the customer's current Supplier should remain the customer's Supplier by default with no break in service.

7. Customer Information. Upon acceptance of an Enrollment Request, as

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1 When developed and available, a universal identifier or a Service Delivery Point Identifier along with a service address zip code shall be the required fields for validation.

described in the Customer Information Document, the Utility (or functional equivalent) shall provide to the Supplier account-specific information, including: name; billing address; service address; Utility account number; telephone number; budget bill indicator; Service Delivery Point Identifier, if available; universal identifier, if available; rate class and sub-class (if applicable); riders (if applicable); Load Profile reference category; meter read date or schedule; meter type; hourly meter data indicator; the most recent thirteen (13) months of historical usage, including, monthly metered usage, and when available, applicable metered interval usage; and any other pertinent customer information, *e.g.*, congestion zones or gas pools.

8. Switching to Default Supply. To the extent customers choose to switch from a Supplier to the Provider of Last Resort, the business rules outlined herein shall be applicable to the Provider of Last Resort.

a. Rules on customers returning to Provider of Last Resort service and any restrictions on their ability to shop for a new Supplier need to be consistent across the state and clearly communicated to the customer in writing. The customer also must be provided appropriate time to take action to avoid any such restrictions.

B. CUSTOMER DROPS BY SUPPLIER. As well as requiring the Supplier to comply with the applicable consumer protection laws, the following process outlines the steps for a Supplier dropping a customer.

1. If the Supplier decides to drop a customer (*e.g.*, for non-payment, breach of contract, or end of term), then the Supplier shall send a Drop Request *via* the appropriate SET protocol to the Utility (or functional equivalent).

2. The Utility (or functional equivalent) shall send a Drop Response *via* the appropriate SET protocol along with the effective date of the drop within one (1) business day to the Supplier.

3. The effective date of the drop shall be the next meter read, commencing not less than eight (8) business days after the Drop Request has been received by the Utility (or functional equivalent) unless the Supplier agrees to pay for a special meter reading, with the cost of a special meter read stated in the Utility's tariff.

4. The Utility (or functional equivalent) shall send notice to the customer regarding the drop and the customer's opportunity to select a new Supplier, if applicable, or return to Provider of Last Resort service, if applicable.

TELEPHONIC ENROLLMENT

Suppliers may telephonically enroll all customers under the following conditions:

A. While engaged in a telephone conversation with the potential customer, the Supplier must audio record or third party verify (*via* either a live operator or interactive voice response (IVR)) the following information in order to substantiate the customer enrollment:

1) A statement that the telephonic enrollment conversation between the customer and the Supplier is being recorded.

2) A statement from the customer acknowledging the date of the call.

3) A statement from the customer agreeing to enroll with the Supplier.

4) A statement from the customer acknowledging:

a) the customer's name;

b) the customer's service address; and

c) the customer's Utility account number or other unique identifier, *e.g.*, mother's maiden name, last four digits of the customer's social security number, or birth month and day.

At the Supplier's request, the Supplier may request additional information from the customer, including additional information to verify the customer's identity.

5) For customers who have not previously reviewed the terms and conditions of the offer, the Supplier shall provide the terms and conditions in accordance with the applicable consumer protection laws. If the consumer protection laws provide for a period for reconsideration during which the customer can rescind the enrollment, then the terms and conditions shall include a toll-free telephone number for the customer to exercise such rescission.

B. In the event of any dispute involving a telephonic enrollment, the Supplier must make an audio recording of the customer enrollment available within five (5) business days of a request by the applicable regulatory authority.

INTERNET ENROLLMENT

A. Suppliers may enroll any customer by means of the Internet provided that the terms and conditions of the agreement are publicly posted and accessible to the user. These terms and conditions must comply with all applicable legal requirements.

B. The rules to facilitate Internet enrollment are outlined herein.

1) The means of all electronic enrollment, renewal, renegotiation and cancellation information transfer between the customer and Supplier must be by an encrypted transaction using Secure Socket Layer or a similar encryption standard to ensure privacy of customer information.

2) Any electronic agreement containing a Supplier's terms and conditions shall be identified by a version number in order to ensure the ability to verify the particular agreement to which the customer assents.

3) The Internet enrollment procedure shall prompt the customer to print or save the terms and conditions to which the customer assents and provide an option to have written terms and conditions sent by regular mail.

4) Upon request by the customer, the Supplier shall make available throughout the duration of the agreement, a copy of the terms and conditions of the agreement version number to which the customer assents. The Supplier must provide to the customer a toll-free telephone number, Internet means, or an electronic mail (e-mail) address for the customer to request this information throughout the duration of the agreement.

5) The Internet enrollment procedure shall require the customer to include, at a minimum, their name, service address, e-mail address, and Utility account number or other unique identifier, *e.g.*, mother's maiden name, last four digits of the customer's social security number, or birth month and day, to effectuate a sign-up, and to "accept" or "not accept" the terms and conditions by checking the appropriate box, which shall be displayed as part of the terms and conditions. Such acceptance or rejection by the customer will be retained, in a retrievable format, by the Supplier.

6) The Internet procedure shall incorporate a 3-day customer cancellation period that automatically provides the ending date of said period substantially in the form that follows:

IF YOU WISH TO CANCEL THIS AGREEMENT, YOU MUST
DO SO BEFORE 12:00 a.m. on _____

This document is section III, exhibit 2 of the CUBR Uniform Business Rules Document, Version 1.1, Dated September 1999.
The CUBR Document should be considered in its entirety. See Appendix for disclaimers.

7) The Supplier must provide a mechanism by which the customer's acceptance or rejection of the terms and conditions are recorded by time and date.

8) After the customer checks the appropriate box relative to the acceptance of the terms and conditions, the Internet enrollment process shall disclose conspicuously that the customer has been enrolled.

9) The Supplier shall provide confirmation notice to the customer, by e-mail at the specified e-mail address or by regular mail at the address specified by the customer.

10) The Supplier shall provide to the customer a toll-free telephone number, an Internet means, and/or an e-mail address for the customer to cancel the agreement within three (3) days from the date on which the customer is enrolled by means of the Internet. If the agreement is canceled, the Supplier will provide the customer with a cancellation number.

C. In the event of any dispute involving an Internet enrollment, the Supplier must provide either a date and time stamped copy of the customer's acceptance of the terms and conditions or on-line access to the same to verify customer enrollment to the applicable regulatory authority within five (5) business days of any such request.

UTILITY CONFIRMATION NOTICE

Dear (CUSTOMER),

We have recently been notified that you have chosen (SUPPLIER NAME) to be your supplier of (electricity/natural gas). This means that your (electricity/gas) will be provided by (SUPPLIER). As your regulated utility, (UTILITY NAME) will still deliver that (electricity/gas) to your home or business.

For questions about your (electricity/natural gas) supply contract or cost, please call (SUPPLIER) at (TOLL FREE or LOCAL PHONE NUMBER). If you have general questions about the program, please call our toll-free customer service number (PHONE).

Your choice of (an electric supplier/a natural gas supplier) is based on an agreement between you and (SUPPLIER). If this information is not correct, please contact us immediately at (PHONE). If we do not hear from you prior to (DATE FOLLOWING 7 CALENDAR DAYS FROM DATE OF LETTER), (SUPPLIER) will be authorized to supply your (electricity/natural gas) for the term of your agreement.

(UTILITY NAME)

IV. CREDITWORTHINESS

A. APPLICABILITY

1. These standards apply to the following circumstances:

a. when the Supplier is offering Consolidated Supplier Billing to electricity and/or natural gas retail customers, or

b. when there is no Independent System Operator (ISO) or functional equivalent and the Utility is exposed to imbalance payment risk by the Supplier.

2. These standards do not apply in circumstances involving credit risks of the Independent System Operator (or functional equivalent), any applicable Power Exchange (or functional equivalent), or wholesale energy suppliers (except to the extent associated with load balancing and settlement by the Utility).

3. These standards do not apply to Dual Billing or Utility Consolidated Billing scenarios.

B. CREDITWORTHINESS DETERMINANTS

1. Under the applicable circumstances as described above in Section A, the Supplier's participation in the Utility's retail access program is contingent upon the Supplier satisfying a credit appraisal based on independent bond/credit ratings and supplying any security that may be found necessary to meet the Utility's credit requirements. Credit appraisals and security requirements may be reviewed by the Utility annually.

2. The Utility's credit evaluation must be completed within ten (10) business days after receiving the Supplier's application. The Utility must provide the rationale for its determination and the calculation supporting the credit limit and any resulting security requirement. The Utility must perform its credit evaluation and associated security calculation in a non-discriminatory manner. The evaluation process and methodology must be approved by the applicable regulatory authority and clearly stated in the Utility's Supplier Tariff.

a. The Supplier must be provided an opportunity to challenge the Utility's determination *via* an expedited process before the applicable regulatory authority. The applicable regulatory authority should rule on the

creditworthiness determination within fourteen (14) days of receipt of the Supplier's request for review.

b. The Supplier must have the opportunity to petition the Utility to re-evaluate its creditworthiness at any time to determine if the Supplier's status has changed. The Utility's credit evaluation must be completed within ten (10) business days after receiving the request. The Utility must provide the rationale for its determination and the calculation supporting the credit limit and any resulting security requirement. The Utility must perform its credit re-evaluation and associated security calculation in a non-discriminatory manner. The re-evaluation process and methodology should be approved by the applicable regulatory authority and clearly stated in the Utility's Supplier Tariff.

3. The Supplier can satisfy the Utility's credit requirement by satisfying any of the following criteria:

a. Having a long-term minimum rating of "BBB-" from S&P's, "Baa3" from Moody's, or "BBB-" from Fitch ("Minimum Rating"); or

b. Having a guarantor with a long-term minimum rating of "BBB-" from S&P's, "Baa3" from Moody's, or "BBB-" from Fitch ("Minimum Rating"); or

c. Having a minimum "1A2" rating from Dun & Bradstreet coupled with 24 consecutive months good payment history;[1] or

d. Posting security in an acceptable form as listed below.

4. The Utility may, at its discretion, reduce or eliminate any security requirements as long as this standard is applied equitably to all Suppliers existing and new.

C. CREDIT EXPOSURE/SECURITY CALCULATION

1. If the Supplier meets the credit requirements listed above, no security will be required.

[1] The 24 consecutive payment history includes industry-related payments to other utilities, including utilities in other states, or to interstate pipelines.

2. If the Supplier does not meet the credit requirements listed above, security in an amount equal to the credit exposure may be sought and provided in a form as set forth below.

3. The maximum security amount is based on the risks of (a) the Utility not being reimbursed for delivery charges by the Supplier providing a Consolidated Bill to retail customers and/or (b) electric and/or natural gas imbalances, if there is no ISO (or functional equivalent). The Supplier shall be responsible for estimating the projected average daily usage which will be the basis of the formulas discussed below.

a. Payment Risks Associated with Supplier Consolidated Billing**:** The maximum security associated with the Supplier billing customers for both delivery and commodity services may be no more than sixty (60) days of the Supplier's customers' projected average daily usage over the next twelve (12) months priced at the Utility's applicable delivery tariff rate, including relevant competitive transition and customer charges.

b. Natural Gas Imbalances**:** The maximum security associated with balancing and settlement risk will be determined for each season. The seasons are defined as Summer (April 1 - October 31) and Winter (November 1 - March 31). This credit exposure may be no more than as determined by: (a) the average daily quantity of the Supplier's customers' projected aggregate consumption, based on the appropriate season of the past year; (b) priced at the average daily closing NYMEX price, at the appropriate hub, plus the average capacity release charge of the appropriate pipeline(s), for the appropriate season of the past year; and (c) times thirty (30) days. The Supplier may, at its option, elect to have the security determined annually, rather than seasonally in which case it will be based on the winter season.

c. Electric Imbalances: Security only may be required by the Utility when there is no ISO (or functional equivalent). The maximum security associated with the electric imbalance risk of the Utility may be no more than as determined by: (a) the average daily quantity (kWh) of the Supplier's customers' projected aggregate consumption over the next twelve (12) months; (b) priced at the average daily real time price or buy back rate as specified in the Utility's tariff, for the area in which the Supplier's customers are located, during the previous twelve (12) months; and (c) times thirty (30) days.

d. Adjustment of Security Levels: After the Supplier serves customers in the Utility's service territory for ninety (90) days, either party has the right to request a change in the Supplier's estimate of charges based on the Supplier's historic information of the customers it serves in the Utility's service

territory. At a maximum, such adjustments can be made on an annual basis.

D. SECURITY INSTRUMENTS

1. At the Supplier's choice, the following are deemed to be acceptable methods for posting security, if required:

a. An advance deposit or prepayment; or

b. A standby irrevocable letter of credit issued by a bank, insurance company or other financial institution with at least an "A" bond rating; or

c. Security interest in collateral found to be satisfactory to the Utility; or

d. A financial guarantee, acceptable to the Utility and the Supplier, by another party or entity with a satisfactory credit rating as described above; or

e. A lockbox mechanism. A lockbox shall reduce any security requirements up to 100% of what would otherwise be required. Under the lockbox mechanism, the Supplier's customers' payments shall be made to a lockbox, which shall be administered by a mutually agreed upon entity. All costs associated with implementing and administering the lockbox shall be the responsibility of the Supplier. The allocation of funds in the lockbox between the Utility and the Supplier, and other administrative rules, must be agreed to by both parties, with the Utility having first rights on funds in the lockbox to off-set Utility charges. The administrative rules shall specify the terms under which the lockbox mechanism shall be terminated for non-compliance. The Utility, after petition to the applicable regulatory authority, is permitted to terminate the lockbox and request full security if expected customer payments are not received in a timely manner; or

f. A security interest in electric Utility-generated receivables. The following security interest shall reduce any security requirements up to 100% of what would otherwise be required. The Supplier grants to the Utility a first-priority, continuing security interest in all of the Supplier's accounts receivable to the extent they are payable with respect to electricity that the Utility provided to service such Supplier's customers. The amount payable to the Utility by each such customer shall be determined based on the proportion of electricity served by the Utility as reflected in the customer's dynamic load profile. During the continuation of such security interest, the Supplier shall irrevocably appoint the Utility as its agent to collect

such accounts receivable and shall agree not to bill any of its customers with respect to electricity that the Utility provided to them; or

g. A surety bond from a bank, insurance company or other financial institution with at least an "A" bond rating; or

h. Other mutually acceptable means of providing or establishing adequate security (*e.g.*, escrow accounts, loss pooling, etc.).

2. If the rating of a bank or insurance company or other financial institution from whom the Supplier has obtained a letter of credit or surety bond falls below an "A" rating, the Supplier shall have twenty (20) calendar days upon written notice to obtain a substitute letter of credit or surety bond from an "A" rated bank or insurance company or other financial institution, if required by the Utility.

3. If the Supplier's credit standing ceases to meet the Utility's credit requirements, then the Utility has the right to require security or prepayment as specified herein. The Utility, however, may not request additional security unless the credit exposure increases by at least 10% as to that Supplier, or a reasonable Utility-specified threshold. If the security is not tendered within twenty (20) calendar days after such request, then the Utility may initiate a process in accordance with the Utility-Supplier Dispute Resolution Process Document. Deposits received in cash will accumulate interest at the applicable rate per annum, approved by the applicable regulatory authority, paid to the Supplier quarterly. If the Supplier subsequently satisfies the credit appraisal without the need for some or all of the security requirement, the Utility shall return the appropriate portion of the Supplier's advance deposit with accumulated interest within twenty (20) calendar days. Similarly, if the Utility's credit risk as to that Supplier is determined to decrease by at least 10%, or a reasonable Utility-specified threshold, relative to the amount of security on deposit, the excess shall be refunded with accumulated interest within twenty (20) calendar days of such determination.

E. CALLING ON SECURITY

1. The Utility may call upon the security posted by the Supplier if the Supplier fails to pay the Utility after all of the following events occur:

a. The period for late payment plus interest ends;

b. Written notice of default is provided to the Supplier;

c. A twenty (20) calendar day period to cure ends; and

d. The Utility provides notice to the Supplier of its intent to call upon the security posted by the Supplier unless the Supplier makes payment in full within five (5) days.

2. The Utility may call upon the security posted by the Supplier without prior notice if the Supplier files a petition in bankruptcy (or equivalent, including the filing of an involuntary petition in bankruptcy against the Supplier, if the petition is not discharged within sixty (60) days).

F. CONFIDENTIALITY

1. The creditworthiness process shall be deemed confidential and not subject to public disclosure, unless otherwise required to be disclosed pursuant to other statutory provisions or if the information is required by the applicable regulatory authority. If information must be disclosed, then the confidentiality of the information shall be maintained consistent with the applicable regulatory authority's rules and regulations pertaining to confidentiality.

V. BILLING AND PAYMENTS

There are three types of billing options: Supplier Consolidated Billing; Utility Consolidated Billing; and Dual Billing. In order to assist the development of a competitive market, Supplier Consolidated Billing, at a minimum, should be fully supported and offered by the Utilities. To the extent the applicable regulatory authority believes that the three billing options should be offered, the following billing specifications describe how the options should be implemented.

A. AVAILABILITY OF BILLING SERVICES

1. The Supplier may select from the available options which billing option(s) to offer its customer(s) in the Utility's service territory.

2. The applicable regulatory authority-approved billing options should be uniformly supported and offered by the Utilities.

3. The Supplier must provide at least sixty (60) days advance notice to the Utility of plans to offer additional billing options.

4. Customers have the right to direct the Billing Party to send their bills to any party for processing and payment. This will enable customers to designate agents to receive, process, and pay their bills *via* an agency relationship.

B. BILLING SERVICE OPTIONS

1. CONSOLIDATED BILLING (Utility Consolidated Billing or Supplier Consolidated Billing). Consolidated Billing is the billing process whereby one party (the Utility or the Supplier) reflects the charges incurred by the customer for a billing period on a single bill.

a. The Billing Party shall render a consolidated bill in accordance with the applicable legal requirements and mutually agreed-upon standards. The Billing Party shall issue a bill directly to the customer or the customer's agent. The customer or its agent shall pay the Billing Party.

b. The Supplier consolidated bill format shall be within the Supplier's discretion.

(1) For commercial and industrial customers, the elements on a customer's bill may be negotiated between the Supplier and its customer.

(2) For residential customers, the Billing Party should be

required to comply with the applicable consumer laws. In addition, the following information should be the maximum required elements on a residential customer bill.

(a) Customer name;

(b) Billing Party account number;[1]

(c) Customer billing address;

(d) Billing Party name, address, and telephone number;

(e) Non-Billing Party name and telephone number, if applicable;[2]

(f) Emergency telephone number, if applicable;

(g) Customer charges, adjustments, and payment due; and

(h) Sufficient space for bill messages by the Non-Billing Party, if applicable.[3]

c. Usage data shall be available as detailed in the Metering Document.

d. The Non-Billing Party shall calculate and send its customers' charges (Non-Billing Party Charges) to the Billing Party *via* the appropriate SET protocol. Nothing in these rules precludes the parties from developing an arrangement for additional billing services.

e. The Non-Billing Party Charges must be received by the Billing Party within seventy-two (72) hours commencing on the first business day following receipt of valid usage data.

(1) If the Non-Billing Party's Charges are sent within the appropriate time frame, then the Billing Party must validate or reject the SET transaction (the

1 If Customer Information has not been provided to the market participants prior to the market opening or as part of pre-enrollment, then the Utility account number is a necessary data element to include on the customer's bill.

2 If the Supplier becomes the sole point of contact for customers, *e.g.*, the Supplier is the distribution customer of the Utility or the Single Retailer Model is implemented, then the Non-Billing Party's name and telephone number shall not be required.

3 If the Supplier becomes the sole point of contact for customers, *e.g.*, the Supplier is the distribution customer of the Utility or the Single Retailer Model is implemented, then sufficient space for bill messages by the Non-Billing Party shall not be required.

Billing Party is validating the file, not the Non-Billing Party's charges). The transaction shall be deemed accepted, unless the Billing Party sends a rejection along with the appropriate rejection code *via* the appropriate SET protocol within forty-eight (48) hours commencing on the first business day following receipt. If the transaction is deemed accepted, then the Billing Party is responsible for notifying the Non-Billing Party *via* the appropriate SET protocol when a bill is not issued.

(2) If the Non-Billing Party Charges are sent to the Billing Party outside the appropriate time frame, then the Billing Party should reject the transaction. The Non-Billing Party shall resubmit its charges the following month in accordance with the time line outlined above.

f. The Billing Party shall pay the Non-Billing Party for amounts owed for all undisputed Non-Billing Party Charges regardless of whether the customer has paid the Billing Party. An amount is deemed disputed if the customer or the customer's agent contacts the Billing Party questioning the charges on the bill and the customer or the customer's agent does not agree with the Non-Billing Party's charges. The Non-Billing Party shall be made aware of any disputed charges *via* the appropriate SET protocol. If the dispute is not rectified, the Non-Billing Party may resolve the dispute through the applicable dispute resolution process.

g. The Billing Party shall pay the Non-Billing Party in accordance with the payment terms applicable to the relevant customer class, as defined in the Utility's tariff schedules. For example, if a customer or the customer's agent has fifteen (15) days to pay the Utility according to the Utility's tariff, then the Billing Party has fifteen (15) days to pay the Non-Billing Party.

(1) The due date for payment shall be based on the receipt of a valid SET transmission of the Non-Billing Party Charges.

(2) The Billing Party shall make payments of funds payable to the Non-Billing Party by Electronic Funds Transfer (EFT) with remittance advice to a bank designated by the Non-Billing Party.

h. If the Non-Billing Party does not receive payment for undisputed charges within the appropriate time frame, then the Non-Billing Party may provide notice of breach to the Billing Party at any time thereafter. Upon notice of a breach, the Billing Party shall have twenty (20) calendar days to cure. If the Billing Party has not cured within twenty (20) calendar days, the Billing Party must pay simple interest on the unpaid amount calculated at the lower of (a) the Interest Index or (b) six (6) percent. The rights and remedies associated with breach of contract are not modified by these rules.

i. If the Utility is the Billing Party and an account is over 90 days overdue, then at the Utility's request, the account shall convert to Dual Billing for the next billing cycle. Any past-due notice from the Utility should alert the customer that the customer may be converted to dual billing. The Utility shall notify the Supplier of the conversion *via* the appropriate SET protocol at least ten (10) business days before the customer's next meter read date.

j. If the Billing Party provides a budget billing option, the Billing Party must provide a budget billing option for both Utility and Supplier charges. If the Billing Party does not provide a budget billing option for its charges, then the Billing Party should not have to provide budget billing for the Non-Billing Party's charges. There should be no obligation for the Supplier to offer budget billing for any customer class.

k. If the Utility is responsible for reading the meter, the Supplier has the right to request an adjustment to the customer's meter read/billing cycle. The Supplier must select another Utility-defined meter reading schedule for that account, unless the customer has remote meter reading capability, then the Supplier has the right to arrange for a different meter read/billing cycle. If the Supplier is reading the meter, the Supplier can change the meter read/billing cycle. When there is competitive metering, the parties can make commercial arrangements regarding meter read/billing cycles.

l. Outstanding prior balances are not transferred when a customer switches from the Utility to a Supplier, switches from one Supplier to another, or switches from a Supplier to default service. The Utility may deny Utility Consolidated Billing if the customer's account is at least ninety (90) days delinquent.

m. If the Supplier's ability to discontinue service for non-payment is limited or otherwise compromised by regulatory requirements, then the Supplier shall have access to uncollectible fund accounts and universal service funds.

2. DUAL UTILITY AND SUPPLIER BILLING. Dual Utility and Supplier Billing is the billing process whereby the Utility and the Supplier send separate bills directly to the customer.

a. The Utility and the Supplier shall render individual bills directly to the customer or the customer's agent in accordance with the applicable legal requirements. The customer or its agent shall pay the Utility and the Supplier separately.

b. The Supplier's bill format shall be at the Supplier's discretion.

(1) For commercial and industrial customers, the elements on a customer's bill may be negotiated between the Supplier and its customer.

(2) For residential customers, the Billing Party should be

required to comply with the applicable consumer laws. In addition, the following information should be the maximum required elements on a residential customer bill.

(a) Customer name;

(b) Billing Party account number;[4]

(c) Customer billing address;

(d) Billing Party name, address, and telephone number;

(e) Emergency telephone number, if applicable; and

(f) Customer charges, adjustments, and payment due.

c. Usage data shall be available as detailed in the Metering Document.

d. Whether the Supplier offers budget billing for any customer class shall be at the Supplier's discretion.

e. If the Utility is responsible for reading the meter, the Supplier has the right to request an adjustment to the customer's meter read/billing cycle. The Supplier must select another Utility-defined meter reading schedule for that account, unless the customer has remote meter reading capability, then the Supplier has the right to arrange for a different meter read/billing cycle. If the Supplier is reading the meter, the supplier can change the meter read/billing cycle. When there is competitive metering, the parties can make commercial arrangements regarding meter read/billing cycle.

f. Outstanding prior balances are not transferred when a customer switches from the Utility to a Supplier, switches from one Supplier to another, or switches from a Supplier to default service.

g. If the Supplier's ability to discontinue service for non-payment is limited or otherwise compromised by regulatory requirements, then the Supplier shall have access to uncollectible fund accounts and universal service funds.

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4 If Customer Information has not been provided to the market participants prior to the market opening or as part of pre-enrollment, then the Utility account number is a necessary data element to include on the customer's bill.

VI. ELECTRIC METERING

Meter Standards and Protocols Manual

CONTENTS

ELECTRIC METER SERVICE

Competitive electric meter services will be performed by a Meter Service Provider (MSP). MSP services will be the responsibility of the party indicated in the customer's enrollment and/or account maintenance transactions. A MSP shall provide service in accordance with the applicable regulatory authority regulations and all standards and protocols found herein.

A. METER SAFETY, SEALING AND SECURING

This section identifies minimum safety and security requirements for Meter Service Providers (MSPs), including meter installation, meter maintenance, and testing of meters and metering equipment used in the state. Note that current transformers (CTs) and potential transformers (PTs), as well as communication components, are considered part of the metering system.

1. Safety-Related Reporting Requirements

a. Meter Service Providers (MSPs) and Meter Reading Service Providers (MRSPs) must notify appropriate parties if they encounter, and are unable to correct, safety-related or hazardous conditions found on a customer's premises. Appropriate parties for safety-related issues include the following:

(1) Customer.

(2) Utilities.

(3) Suppliers.

(4) Other competitive entities providing service to the customer.

(5) Local inspection agency/appropriate regulatory authority.

(6) Other parties that may have a material interest in the defect or condition.

b. These conditions shall be reported using the appropriate SET protocol within one (1) business day of discovery.

2. Safety-Related Inspection Requirements. The following safety inspections must be completed by the Meter Service Provider prior to performing meter work on site. Meter work includes, but is not limited to, meter installation, replacement, maintenance, programming, and testing.

Meter Service Provider and Meter Reading Service Provider (as applicable) workers shall visually inspect meter sites for the conditions listed below. This list is not intended to cover all possible

situations that could be faced by workers; rather MSP and MRSP workers should identify these and other conditions if they pose a potential threat to the safety and property of others.

a. Customer Life Support Visual Inspection

(1) If a customer's premises has a life support device or equipment, and a life support seal or sticker appears on the meter, or the Meter Service Provider has been otherwise notified, the standard statewide life support seal (see Meter Securing and Sealing Requirements below) shall be installed on the meter ring to prevent avoidable service interruption during metering work.

(2) When a meter has been properly marked for customer life support, (that is, when a life-support seal or hardware is found on customer meter covers, meter panels, test switches and/or metering transformer panel sections), meter workers shall be cautious in performing meter work so as not to interrupt electric service to the customer's premises.

(3) If service will be or is likely to be unavoidably interrupted during meter work, the meter worker shall notify the customer and obtain the customer's consent prior to performing work.

(4) If the Meter Service Provider determines that life support equipment is in use on a customer's premises and the customer's record does not contain life support information, the MSP shall notify the Supplier, the Utility, and the Meter Reading Service Provider of the presence of life support equipment.

b. Electrical Hazards Visual Inspection. The Meter Service Provider shall perform visual checks of various potential electrical hazards. These inspections include the following:

(1) Exposed wiring.

(2) Damaged sockets (loose or burnt wiring or jaws).

(3) Auto-bypass devices (load jaws still hot when meter removed).

(4) Loose or missing screws (*i.e.*, in bypass area).

(5) Missing panels.

(6) Loose or broken service insulators.

(7) Service wires in bad condition/order.

(8) Missing meter.

(9) Improper grounding conditions.

(10) Fused neutral conductor of a 2 wire or 3 wire single phase service.

(11) Defective service switch/disconnect.

(12) New installations which fail to conform with the state's electric service requirements.

In addition to the inspections listed above, for 480 Volt service, the meter worker shall ensure that a 480 V sticker is in place on the meter panel near the meter before leaving the site.

c. Physical Hazards Visual Inspection. The Meter Service Provider shall perform visual checks of various potential physical hazards. These inspections include the following:

(1) Tripping hazards (slippery or uneven surfaces).

(2) Debris or materials stored in the working space.

(3) Overhead hazards (stored materials or workers above meters).

(4) Environmental hazards, such as caustic or acidic chemicals, volatile chemicals, loud noises, biological agents, etc.

(5) Inadequate or unsafe access.

(6) Meter mounting hazards, such as loose meter mounting, undue vibration, inability to securely seal meters, unleveled meters, etc.

d. Hazards Related to Customer Premises. The Meter Service Provider shall perform visual checks of various potential hazards related to customer premises. These inspections include the following:

(1) Unsafe conditions related to customer-owned stairs, railings, platforms, etc.

(2) Vicious or unpredictable animals.

(3) Insects, snakes, rodents and other vermin in or around doors and electrical panels.

3. Site Verification Inspection Requirements. The following inspections are completed by the Meter Service Provider prior to performing meter work on site. Meter work includes, but is not limited to, meter installation, replacement, maintenance, programming, and testing.

Meter Service Provider workers shall 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 requested by the customer.

a. Metering Verification Required Checks.

(1) Verify the meter type is certified for use in the state.

(2) Verify the customer and customer account records match the installed meter or meter to be installed, including the billing constant, meter number, address, etc.

(3) Verify the meter installed, or to be installed, matches the service characteristics (voltage, form, etc.) requested by the customer.

b. Communication Verification Required Checks.

(1) Verify telephone service or other communication devices, if remotely read, are appropriate for the requested service.

(2) Verify successful communication "handshakes" and data retrieval, if remotely read (this can be done by another worker at a remote location). Note that data accuracy need not be verified at this time.

(3) Verify successful meter reading, if manually read.

c. Instrument Transformer-rated Meter Sites Required Checks.

(1) Verify the billing constant, compare records with site CT and PT ratios, when these instrument transformers are accessible.

(2) When instrument transformers are not accessible, then the Meter Service Provider shall either (a) notify the Supplier, the Meter Reading Service Provider, and the Meter Data Management Agent or (b) ensure that such notification was previously provided.

(3) Check for improper wiring and related conditions. The following list identifies minimum requirements and does not preclude Meter Service Providers from performing additional checks:

(a) Shorted current by-pass links,

(b) Reverse wired current secondary,

(c) Unmatched voltage and current circuits,

(d) Pinched or rubbed secondary wires near panel hinges.

(e) Customer load exceeding instrument transformers minimum/maximum operating limits.

d. Pole-Mounted Meter Sites Required Checks

(1) Check for open cutouts or blown triple link fuses.

(2) Verify that grounding electrode conductors and connections are not broken at any point between the service equipment enclosure and the ground rods or other approved grounding electrode.

(3) If the MSP encounters and is unable to correct identified problems with a pole-mounted meter site, the following parties shall be notified:

(a) Customer,

(b) Utility,

(c) Supplier,

(d) Other competitive entities providing service to the customer,

(e) Local inspection agency/applicable regulatory agency,

(f) Other parties that may have a material interest in the defect or condition.

e. Pad-Mounted Meter Sites Required Checks.

(1) Check primary metering components:

(a) Verify the meter enclosure attached to the primary metering cabinet is secured and lockable,

(b) Verify the meter pedestal installation is mounted securely and that the cabinet is lockable.

(2) Cabinets:

(a) Verify that the cabinet is free of obvious shipping damage, paint damage, or corrosion,

(b) Verify that exterior warning labels are properly attached.

(3) Cabinet Safety:

(a) Verify that there is at least one penta-head security bolt permanently attached to high voltage compartment door(s) and door locking handle,

(b) Verify the secondary non-polarity neutral points and meter enclosure/pedestal are electrically connected to the ground bus,

(c) Verify that all metering electrical connections are secured and properly made.

4. Metering System Sealing And Locking:

a. Life Support Seal. The standard physical identification marker for a customer's premises that has a life support device or equipment shall be a life support seal. The seal can either be white with red lettering or red with white lettering and must have the caduceus symbol on it.

b. Meter Securing and Sealing.

(1) The meter shall be secured into the socket using a ring. The ring shall be secured with a seal.

c. Meter Panel Sealing.

(1) The meter panel shall be secured with a seal.

(2) The seal used for sealing the metering system shall be a wire type, non-lead-based seal which contains the identity of the Meter Service Provider or, when a customer takes service directly from the distribution system, the Utility. The identification on the seal may be a company name (or abbreviation) or the initials of the company. A company logo is not, by itself, an acceptable identification.

d. Meter Socket Covering, Securing and Sealing. When a new meter socket is energized and a meter is not installed, or when a meter is removed from an energized meter socket, the socket shall be covered with a clear plastic cover and secured with a ring. The ring shall be secured with a seal.

5. Meter Security and Accessibility. The following actions designed to ensure meter security and verify accessibility must be completed when performing meter work on site. The Meter Service Provider shall visually inspect meter sites for the following conditions:

a. Evidence of tampering or energy diversion:

Meter tampering and energy diversion may be a significant problem in the state. To minimize the effect of meter tampering and energy diversion the cooperation of all market participants is necessary. Meter Service Providers and their employees need to be aware of techniques used by individuals to steal energy, and how they assist in the minimization of theft and the apprehension of violators.

Meter Service Provider workers shall 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, Meter Service Provider workers should, at a minimum, be able to identify and report these conditions.

(1) Verify general condition of the metering installation:

- When previous inspections or other information indicates the possibility of tampering at a meter site, Meter Service Provider workers should be aware of a customer's significant connected loads and current energy consumption,
- Check for irregularities in the service conductor's insulation ("skinned" insulation, newly-taped sections of conductors, burned or pitted service conductors, etc.),
- Check for unauthorized connection in the overhead service entrance, on the line side of the meter or metering transformers, or in the unsealed underground pull sections or pull cans,
- Check for unauthorized seals and unsealed or improperly sealed conditions on the line side raceways, test block compartments, test switch covers, and meter sealing rings,

- Check suspicious wiring installations that do not appear to conform to building codes or conform to standard utility practice,

- Check for jumpers across current leads,

- Check for jumpers around the lock fuse - if a lock fuse jumper is found, a regular meter test shall be performed - the jumper should be left as found, and this condition reported on the meter test report,

- Check for blown (or loosened) fuses in one leg of a three-wire, old sequence service,

- Check for infractions in meter register/program (demand resets, meter program tampering, etc.).

(2) Inspect the condition and operability of the following components:

- Meter cover - check for an unusually clean cover, small holes in the cover, burn marks on or near the cover, visible fingerprints inside the cover,

- KWH register - check the KWH dial pointer alignment, register mesh, and register gears,

- Meter disk - check disk alignment to magnets, irregularity of disk rotation, foreign objects or materials on disk/bearing, and scratches or wear marks on the disk,

- Test blocks - check for damaged wiring between the test block and meter, unusual marks, scratches or burns on test blocks, and other indications of defective test blocks,

- Meter base - check for unusual marks and mushroomed screw slots on potential links, broken meter seals, unusual wear or scratches, burns, or pit marks on meter stabs/blades/terminals,

- Meter socket - check for unusual wear or scratches, burns or pit marks, irregular meter socket voltages, circuit bypass jumpers,

- Hidden “service riser” taps and unmetered circuits utilizing relay devices - check for unusual noises that could indicate a relay opening when the meter is removed from the socket.

(3) Meter Service Providers must notify appropriate parties if they encounter evidence of meter tampering, energy theft, or meter security compromise on a customer's premises. Appropriate parties for these issues include the following:

- Utility,
- Supplier,
- Other competitive entities providing service to the customer.

b. Meter Security for Programmable Meters. If a programmable meter is installed, a security password shall be applied to prevent unauthorized access to the programmable meter and unauthorized modifications of the meter data and program.

B. METER INSTALLATION AND SERVICE EQUIPMENT REQUIREMENTS

Meter Service Providers must follow established procedures which include, as a minimum, the following provisions or their equivalents. Note that the listed provisions do not necessarily include all procedures for meter installation, and may be supplemented by the MSP to achieve improved safety, accuracy or efficiency.

1. Service Entrance Requirements. The Electric Utilities Service Entrance Requirements Committee (EUSERC) manual will be used as the basis for service entrance requirements in the state. Note that all Utilities do not accept all of the EUSERC requirements, exceptions are noted in the EUSERC manual.

2. Meter Installation – Existing Sites

a. Provisions for Self Contained Meters

(1) Verify the type and size of new metering is appropriate for the site.

(2) Take a closing read on the existing meter.

(3) On interval meters, verify that the meter is not displaying a low battery warning. If the meter is displaying a low battery warning, do not remove the meter and report the situation to the old Meter Service Provider or meter owner.

(4) For meters with no bypass, establish communications with the customer and the Supplier to determine when the load may be disconnected and the existing meter replaced.

(5) For meters with a bypass, the meter socket shall be bypassed and de-energized before replacing the meter.

(6) Read and record the voltage at the meter socket.

(7) Verify a reading of "0" volts between the line and load sides of the test blocks.

(8) Install the new meter.

(9) Take an initial read on the newly installed meter.

b. Provisions for Transformer-Rated Meters (CT Meters)

(1) Verify the type and size of new metering is appropriate for the site.

(2) Take a closing read on the existing meter.

(3) On interval meters, verify that the meter is not displaying a low battery warning. If the meter is displaying a low battery warning, do not remove the meter and report the situation to the old Meter Service Provider or meter owner.

(4) Open the test switch cover, then read and record the voltage at the test switch.

(5) Operate the test switch or test block to de-energize the meter socket.

(6) Install the new meter.

(7) Verify system voltage before closing the voltage switches on the test switch.

(8) Take an initial read on the newly installed meter.

3. Meter Installation - New Sites. Meter installation at a new site or premises requires the coordination of the Supplier, the Utility and the customer to achieve new meter sets and service connection in a timely manner. There are four processes or groups of provisions that apply to the installation of meters at new sites. Note that the provisions listed below do not apply to a socket or panel replacement due to equipment failure.

a. Provisions for Meter Installation: Self-Contained Metering (Utility-Owned Conductor)

(1) The MSP verifies the customer's application is on file with the Utility and that a Supplier has been specified.

(2) The MSP verifies the customer (or other entity, as permitted by the applicable regulatory authority and/or the Utility) and the Utility have completed the line extension from the distribution system.

(3) Upon completion of the line extension, the Utility:

- Energizes the meter panel,
- Installs a plastic socket cover and a sealing or locking ring on the meter socket,
- Installs a seal on the pull section, and
- Notifies the customer and Supplier of completion.

(4) The MSP verifies that the appropriate regulatory authority performs the final electrical inspection. Typically, this information must be received from the customer or the Supplier.

(5) The MSP installs the meter and notifies the customer, the Utility, and the Supplier of completion.

b. Provisions for Meter Installation: Self Contained Metering (Customer-Owned Conductor)

(1) The MSP verifies the customer's application is on file with the Utility and that a Supplier has been specified.

(2) The MSP verifies the customer (or other entity, as permitted by the applicable regulatory authority and/or the Utility) and the Utility have completed the line extension from the distribution system.

(3) The Utility verifies that the appropriate public authority performs the final electrical inspection. Typically, this information must be received from the customer or the Supplier.

(4) Upon completion of line extension and verification of the final electrical inspection, the Utility

- Energizes the meter panel,

- Installs a plastic socket cover and a sealing or locking ring on the meter socket,

- Installs a seal on the pull section, and

- Notifies the customer and Supplier of completion.

(5) The MSP installs the meter and notifies the customer, the Utility, and the Supplier of completion.

The following processes are based on the assumption that the state's standards for instrument rated services are cold sequence metering (not hot sequence metering). Cold sequence metering is when the customer's main switch is placed before the metering equipment. Also note that these processes are requiring the inspection agency/appropriate regulatory authority to inspect the metering wiring on the instrument rated services.

c. Provisions for Meter Installation: Instrument Rated Metering

(1) The MSP verifies the customer's application is on file with the Utility and that a Supplier has been specified.

(2) The customer forwards a proposed service equipment drawing to the MSP. The service equipment requirements for the state provide additional information on how a customer prepares the service equipment proposal.

(3) The MSP notifies the customer, Utility, and Supplier that the service equipment drawing has been approved.

(4) The MSP verifies the customer (or other entity, as permitted by the applicable regulatory authority and/or the Utility) and the Utility have completed the line extension from the distribution system.

(5) Upon approval of the service equipment proposal and completion of the line extension, the Utility

- Locks the customer's main switch in the open position,

- Energizes the panel,

- Notifies the customer and Supplier that the panel is energized.

(6) The MSP installs instrument transformers and wires the meter socket and test switch. Upon completion, the MSP leaves the panel accessible and notifies the

appropriate local inspection authority/applicable regulatory authority that the wiring is complete.

(7) The local inspection authority/applicable regulatory authority inspects the metering wiring and affixes an inspection sticker to the panel.

(8) The customer notifies the Supplier that the final electrical inspection is complete.

(9) The MSP then

- Installs the meter,
- Removes the lock from the customer's main switch, and
- Notifies the customer and Supplier that the installation is complete.

d. Provisions for Meter Installation: Self Contained and Instrument Rated Combination

(1) The MSP verifies the customer's application is on file with the Utility and that a Supplier has been specified.

(2) The customer forwards a proposed service equipment drawing to the MSP. The service equipment requirements for the state provide additional information on how a customer prepares the service equipment proposal.

(3) The MSP verifies the customer (or other entity, as permitted by the applicable regulatory authority and/or the Utility) and the Utility have completed the line extension from the distribution system.

(4) Upon approval of the service equipment proposal and completion of the line extension, the Utility:

- Locks the customer's main switch in the open position on the instrument rated service(s),
- Installs plastic socket cover(s) and sealing or locking ring(s) on the self contained services,
- Energizes the panel,
- Notifies the customer and Supplier that the panel is energized.

(5) The customer notifies the Supplier that the final electrical inspection is complete on the self contained meter(s).

(6) The MSP then

- Installs self contained meter(s),
- Installs instrument transformers and wires the meter socket and test switch,
- Leaves the panel accessible for the local inspection authority/applicable regulatory authority,
- Notifies the appropriate local inspection authority/applicable regulatory authority that the wiring installation is ready for inspection,
- Notifies the customer and Supplier that the metering installation is complete.

(7) The local inspection authority/applicable regulatory authority inspects the metering wiring and affixes an inspection sticker to the panel.

(8) The customer notifies the Supplier that the final electrical inspection is complete on the instrument rated meter(s).

(9) The MSP then:

- Installs instrument rated meter(s),
- Removes the lock from the customer's main switch,
- Notifies the customer and Supplier that the metering installation is complete.

4. Rewires and Service Upgrades. If a customer rewires or upgrades electrical service and metering equipment, the MSP may remove the meter before the work on metering equipment starts. Reinstallation of the meter is subject to the same requirements of Section (3).

C. METER MAINTENANCE AND TESTING. The primary purpose of the maintenance and testing program is to assure that the meter population supported by Meter Service Providers is reliable and accurate as long as meters are in service. The maintenance and testing 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 statistical sampling plan. MSPs may establish maintenance and testing programs that exceed the basic requirements set forth below.

1. Maintenance and Testing Schedule. Electric meters shall be maintained, at a minimum, according to the following meter maintenance and testing schedule:

Maintenance and Testing Frequency	Customer Maintenance and Testing Criteria
One Year Interval	Customer's annual peak demand of 500KW or higher
Five Year Interval	Customer's annual peak demand between 50 and 499 KW
All Other Meters	Formal sampling plan performed annually or tests done upon request and removal, where applicable

2. Maintenance and testing upon request. The MSP shall perform meter maintenance and testing when requested by a customer, Supplier, or Utility. The party requesting maintenance and testing is responsible for paying associated fees, except as provided below.

a. A customer is entitled to request one maintenance and testing inspection without charge in a twelve (12) month period. The Supplier shall be responsible for bearing the cost of the inspection.

b. When a requested maintenance and testing inspection results in the identification of fraud or electricity theft by a customer, the fee for the inspection may be charged to the customer.

3. Sampling Plan Requirements. American National Standards Institute Standards, ANSI Z1.4 or Z1.9, shall be used as the basis for the statistical sampling of meters. Generally, inspection level General II (G-II) shall be used unless other inspection levels are justified.

4. Correction Criteria

a. The correction criteria for the meter population are based on a trigger criterion and an action criterion, which are specified in the table below. The trigger criterion refers to the error level at which additional testing must be considered and performed. The action criterion refers to the error level at which corrective measures must be considered and performed.

Criteria for required corrections

Sampling plan applied on:	Trigger Criterion	Action Criterion
Overall meter population	2.5% AQL	4% AQL
A group or type of meters	2.5% AQL	10% AQL

b. The Acceptable Quality Level (AQL) is the maximum percentage of non-conforming meters allowed in the meter population or group of meters. Non-conforming meters are those found outside the required accuracy limits for individual meters. The applicable regulatory authority-required accuracy limits are found in the respective Utility tariffs (generally around 2%). The overall meter population includes all meter types serviced by an MSP, and is not subdivided into any groups of meters or meter types.

c. When the trigger criterion is not met during the implementation of a periodic or statistical sampling plan, the second or more sampling plans for further testing and checking shall be required to monitor the accuracy performance of the overall meter population, groups, or types.

d. When the action criterion is not met during the implementation of a periodic or statistical sampling plan, corrective actions shall be taken to correct the problems. Such corrective actions may lead to removal of certain inaccurate and aging meter groups or types.

5. Communications with Meter Data Management Agents (MDMAs)

a. The MSP will notify the MDMA when either of the following conditions exist:

(1) An individual meter fails to meet the accuracy standard set by the Utility tariff.

(2) The AQL for the meter population or for a group of meter types reaches the trigger or action criterion.

b. The MDMA is responsible for monitoring the quality of the data from the meter and will confer with the MSP regarding potential data problems with the meter (see Data Quality below).

D. GUIDELINES FOR METER TESTING & TEST STANDARDS

1. Calibration and Maintenance of Test Standards. The following are the requirements for maintenance and calibration of test standards used for testing the accuracy of electric meters in the field or in the shop:

a. Test Standard. Each Meter Service Provider shall use a test standard that is within 0.1% of a reference test standard. Each test function of a test standard shall be checked, calibrated and compared with a reference standard every six months.

b. Reference Test Standard. A reference test standard, certified according to NIST requirements shall be used as the accuracy reference in the laboratory or meter shop. The reference test standard shall be certified annually.

c. Portable Test Standard. A portable test standard shall be used to certify the accuracy of meters in the field. Each test function of a portable test standard shall be checked, calibrated and compared with a reference standard every six months.

2. Meter Test Matrix. The state's meter system testing matrix shall be used to govern the types of tests performed on meter installations in the state. The matrix is designed to: 1) ensure and certify the accuracy of metering systems to within limits prescribed by the Utility tariff, and 2) provide consistency of testing among customers. The metering system, is 1) the meter itself, or 2) the meter and its attached equipment or module(s), 3) CTs & PTs and 4) communication mechanisms.

State Meter System Testing Matrix

The following matrix indicates which testing task can be applied to a meter technology and the meter system, and it serves as a guide in meter system testing. Some of the specific tasks may not apply to newer meters:

		TASK									
CODE	**Type of Meters/Registers**	**1** Voltage Test	**2** Light & Full Load or Customer-Load Test	**3** Demand Test	**4** Register Verification	**5** Phase Angle Test	**6** Separate Element Check	**7** Burden Test	Possible Other Types (4)	COMMENTS	**CODE**
(a)	Self-Contained kWh Meters	**X**	**X**						**(g), (j)**	Mechanical Meter	**(a)**
(b)	Transformer-Rated kWh Meters	**X**	**X**			**(3) (5)**	**X**	**X**	**(g), (j)**	Mechanical Meter	**(b)**
(c)	Hybrid Meters	**X**	**X**	**(1)**	**X**	**(3) (5)**	**(5)**	**(5)**	**(i), (j)**		**(c)**
(d)	Solid State Meters	**X**	**X**	**(1)**	**X**	**(3) (5)**	**(5)**	**(5)**	**(g), (i), (j)**		**(d)**
(e)	Transformer-Rated kVARh Meters	**X**	**X**			**X**	**X**	**X**	**(j)**	Mechanical Meter	**(e)**
(f)	Multi-Quadrant Meters	**X**	**X**	**(1)**	**X**	**(3)**	**X**	**(5)**	**(g), (j)**		**(f)**
(g)	Solid State Recorders	**X**		**X**							**(g)**
(h)	Mechanical Registers			**(1)**	**(2)**				**(g), (j)**		**(h)**
(i)	Electronic Registers			**(1)**	**(2)**				**(g), (j)**		**(i)**
(j)	Pulse Devices			**X**							**(j)**
(k)	Self-Contained Network Meters	**X**	**X**				**(3)**		**(g), (j)**		**(k)**

(1) Performed if demand is present. (2) Energy Consumption Investigation (ECI) is necessary. (3) Performed when deemed necessary or requested by customers. (4) The alphabetical codes in the "Possible Other Types" column refer to the "Code" column on this matrix and indicate that additional tests must be performed as required if the other types exist at the sites. (5) When meter is "Transformer Rated".

3. Voltage Test. The voltage test is performed to determine the service voltage prior to the start of meter work, and to detect the presence of a short-circuit or other hazardous condition in a customer's equipment or panel.

a. The voltage test shall, at a minimum, measure the secondary voltage, with an approved voltmeter, between the line phases and between the line and ground, even if it is an ungrounded service. This test shall require the recordation of voltage readings on the test tag. Nominal voltages have an allowable tolerance of 5 percent.

b. The MSP shall notify the Utility of voltage readings outside the allowable tolerance, as set forth below.

(1) Secondary Distribution Voltages:

- Nominal voltages and allowable limits for secondary voltages,

Nominal Voltage (V)	Secondary Maximum (V)	Secondary Minimum (V)
120	126	114
208	218	198
240	252	228
277	291	263
480	504	456

- Service voltages and allowable limits for secondary voltages,

Service Voltage (V)	Measured Voltage (V)	Secondary Maximum (V)	Secondary Minimum(V)
120/240 V 3w 1ø	120 V Phase to Ground 240 V Phase to Phase	126 252	114 228
120/208 V 3w 1ø	120 V Phase to Ground 208 V Phase to Phase	126 218	114 198
120/208 V 4w 3ø	120 V Phase to Ground 208 V Phase to Phase	126 218	114 198
120/240 V 4w 3ø	120 V Phase to Ground 208 V Phase to Ground 240 V Phase to Phase	126 218 252	114 198 228

277/480 V 4w 3ø	277 V Phase to Ground 480 V Phase to Phase	291 504	263 456
240 V 3w 3ø	240 V Phase to Phase	252	228
480 V 3w 3ø	480 V Phase to Phase	504	456

c. Primary Distribution and Transmission Voltages: These voltages have a secondary voltage rating of 115 V or 120 V. The voltage transformer primary may be connected either wye or delta.

Primary and transmission Voltages with their secondary voltages and ratios that may be found in the state. The list is not all inclusive, each voltage and ratio should be confirmed.

Possible System Voltage (V)	VT Primary Voltage (V)	Secondary Rating (V)	Ratio
2,400/4,160 4W	2,400	120	20:1
4,160 3W	2,400	120	20:1
4,160 3W Δ	4,200	120	35:1
7,200 3W Δ	7,200	120	60:1
12,470 3W	12,000	120	100:1
7,200/12,470 4W	7,200	120	60:1
7620/13,200 4W	7620	120	63.5:1
8400/14560 4W	8400	120	70:1
14,400/24,900 4W	14,400	120	120:1
20,125/34,500 4W	20,125	115/67.08	175/300:1
34,500 3W	20,125	115/67.08	175/300:1
55,000 3W	34,500	115/67.08	300/500:1
60,000 3W	34,500	115/69	300/500:1
69,000 3W	40,250	115/67.08	350/600:1
115,000 3W	69,000	115/69	600/1000:1
138,000 3W	80,500	115	700:1
230,000 3W	138,000	115/69	1,200/2000:1
345,000 3W	230,000	115	2,000:1
500,000 3W	287,500	115/69	2,500/4,200:1

4. Light Load & Full Load Test or Customer-Load Test. The light load and full load test (customer load test) is performed to measure meter accuracy at various load conditions. Typically, the accuracy of the solid state meters varies minimally in the full and light load conditions. However, the accuracy of mechanical meters is significantly better at full load than at a light load. Therefore, it becomes a common practice to test meters for accuracy at both light and full load conditions.

Light load is 10% of test Amp rating, and full load is 100% of test Amp rating. The light and full load test is performed at 100% power factor to verify the accuracy of the meter by comparing its test results with a standard meter of known traceable accuracy. The customer load test will consist of two or more test runs using the customer's load. Each heavy load test run shall be at least 60 seconds in duration. Heavy load is defined as any load over 10% of the test Amp rating of the meter. Each light load test run shall be at least 90 seconds in duration and shall involve at least two revolutions of the meter disk.

a. No Load or Creep Test (for mechanical & hybrid meters only): Test meters will be energized with no connected load, and the disk observed for rotation. A minimum amount of creep is acceptable if the rotation stops when an anti-creep hole reaches the meter stator.

b. Accuracy test: Single phase and polyphase meters are to be tested with potential coils connected in parallel and the current coils connected in series; or an on-site test can be performed using customer load. The minimum duration of the test will be 1 disk revolution for light load and 10 disk revolutions for full load. For solid state meters, calculated equivalent revolutions will be used. Customer load test shall be at least 60 seconds in duration and shall involve a minimum of two revolutions of the disk for a heavy load test. Light load test runs shall be at least 90 seconds in duration and involve at least two revolutions of the disk.

c. Adjustments: Meters found within the limits required by the applicable regulatory authority-approved tariffs need not be adjusted.

d. Recording of Test Results: Correction factors for light load and full load tests will be recorded as the meter accuracy results as specified in ANSI C.12.1 (1995). For example, for a 0.5% fast and slow meter:

Error Condition	Correction Factor	Accuracy
Fast	0.995	+ 0.5%
Slow	1.005	–0.5%

5. Demand Test. The demand test is performed to ensure the accuracy of the demand function of a meter.

a. Mechanical Demand Meters. Test for the accuracy of the demand registers by checking the marked register ratio and time interval as follows:

- Advancing mechanism - Visually inspect the pusher arm and gears for worn out parts,

- Clutch - Check that the pusher arm returns to zero at the end of interval when the clutch releases it. Verify that this is a smooth operation and that the pusher arm returns to the stop position,

- Timing motor - Check that the timing motor is operating. If the motor is not operating, the demand reading will most likely be off scale,

- Time interval and demand test - Test the time interval to ensure that it is as marked on the register name plate by timing the motor gear and clocking an interval *(i.e.*, 900 seconds for 15 minutes), or performing a demand test. The demand test is performed by minimally applying full load current for 125 disk revolutions on 15 minute demand meters and for 250 disk revolutions on 30 minute demand meters,

- Demand mechanism - Check that the demand reset returns the pointer to zero on a reset action and that the pointer will advance to full scale,

- Reporting - Correction factor for the demand test will be recorded as the meter accuracy result. For example for a 0.5% fast and slow meter:

Error Condition	Correction Factor	Accuracy
Fast	0.995	+ 0.5%
Slow	1.005	–0.5%

b. Solid State Meters and Electronic Registers. Below is a procedure for a demand test on a solid state meter or an electronic register:

- Place the meter register in the TEST MODE,

- Press the reset button to clear all test registers and start a new demand interval,

- Apply full load current for 25 equivalent disk revolutions as a minimum,

- Scroll the register display to show present kW demand. If the kW value is in pulses, calculate the actual kW value,

- Calculate and record the correction factor by comparing the meter kW value with the kW in the test standard,
- Return the meter to the NORMAL MODE.

6. Register Verification. The register verification is performed to ensure that the register components provide and retain accurate billing information.

a. Mechanical Register. Register verification for mechanical register meters shall, at a minimum, require a visual inspection and verification that the register is correct for the watt-hour meter, and that the register constant, gear ratio, and register ratio are correct for the register. Mechanical register verification shall also verify:

(1) Gear mechanisms are clean, and that there is proper engagement between gears, and between the first gear and the disk shaft.

(2) The register ratio is the same as marked. The register ratio (Rr) is determined by counting the number of revolutions required of the first gear to cause the first dial pointer to make one complete revolution.

b. Electronic Register. Because electronic registers are different for each type and manufacturer, the manufacturer's manual should be referred to for specific procedures. Typically electronic register verification shall verify:

(1) Operation of numerical segments and identifiers on the meter display.

(2) The meter is scrolling properly through all registers.

(3) The function of the registers by disconnecting, and then restoring power on the meter. The meter should resume normal display operations and reading after this power outage.

(4) Programming parameters are correct.

(5) The register memory and load profile data is being stored.

7. Phase Angle Test. The phase angle test is performed to ensure the correct wiring for a meter system, and therefore, to ensure the meter site accuracy.

The test should verify that the meter and customer load are arranged in the same phase sequence as the energy supplied by the Utility. During phase angle tests, MSP workers should typically perform the following steps:

a. Verification of the Utility's phase rotation conventions: Refer to specific Utility conventions regarding phase rotation prior to performing this test; also check for correct wiring on reactive metering sites and proper phase shift on each phase circuit.

b. Phase shifting transformer (reactaformer) voltage measurement: Measure and record the secondary voltage to ensure correct voltage is applied to the potential coil in the kVARh meter. If the phase voltage is not correct, check for the following possible errors: 1) incorrect wiring on the phase shifting transformers, and 2) incorrect service voltage.

c. Power Factor Calculation: Calculate the load on the (real power) kWh and the (reactive power) kVARh meters, and the power factor for the site. This power factor is used as a cross check for the measured phase angles.

d. Current Measurement: Measure and record each phase current.

e. Phase Angle Measurement: Use a phase angle meter to measure and record each phase angle.

f. Phase Angle Plot: After measuring all voltages, currents, and phase angles, plot a phase angle test and cross check with the calculated power factor.

8. Separate Element Check. The separate element check is performed to ensure that each element of a meter is in good working condition. This check is necessary because a meter has more than one element, and it still measures energy usage even if one element is burnt or defective.

Separate element checks should, at a minimum, check individual elements for proper disk rotation or registration by performing the following:

a. Forward Rotation Testing: Apply voltage to the appropriate phase potentials and apply current to the corresponding individual elements; then check for forward rotation or positive registration.

b. Check for Correct Phasing: Check that the proper potential coil and current coil are wired correctly in the meter. Typically, if the meter is installed correctly on the socket, the meter disk will rotate forward or positive

registration will occur.

c. Check for Forward Rotation: If an element has no rotation, check for no-load current and for open potential coil(s) with a magnet or an ohmmeter.

d. Special Check for Low Power Factor: Phase angle relationships may cause reverse rotation when the power factor is very low. This condition may also occur when there is an unmetered load or a short circuit, and is only found on three wire three, phase metered service sites.

9. Burden Test. Meter "burden" is the total load or impedance in the current transformer (CT) circuit due to meter coils, leads, and other devices used to connect the meter to the customer's load. The burden test is performed to check for the proper operating conditions of CTs. MSPs conduct this test to verify that the output current is proportional to the CT's nameplate ratio. Below is an example procedure for the burden test on a CT:

a. Procedure: Put built-in burdens of a multi-range Ammeter or burden tester in series with the secondary of the test CT to obtain the Amp readings. These Amp readings should have the same deflection.

b. Possible Problems: If a CT has a reading significantly different from the others, check for shorted turns or other problems, such as short circuited primary turns, short circuited secondary turns, high resistance connections in the secondary circuit, short circuited secondary wiring, or grounding of normally ungrounded wire.

METER SERVICE PROVIDERS

A. METER WORKER QUALIFICATIONS

1. General Qualifications. Three levels or "classes" of meter worker qualifications have been established for Meter Service Provider meter workers.

a. Meter workers performing services on behalf of a MSP must be trained and must exercise due care in performing these functions.

b. A MSP employee who performs metering work is required to have appropriate identification, indicating the worker's employer and the class of meter work the worker is qualified to perform. This identification must be carried by the employee whenever performing meter work.

2. Demonstrated Job Skill Requirements.

a. State Class 1 Qualification

(1) Knowledge of metering types and voltages: Workers with a MSP Class 1 Qualification are permitted to perform work on single phase, socket-based meters, operating at a maximum of 300 volts, phase-to-phase. This level of qualification does not include transformer-rated meters. Also, communication wiring must be outside of energized meter panels.

(2) Work to be Performed. MSP Class 1 Meter Workers may install, remove and replace single-phase, 120/240 volt or 120/208 volt self-contained meters in standard socket based residential-type metering installations. Connections for communication conductors must be outside the energized meter panels.

(3) Safety Skills

- Knowledge of electricity hazards and ability to perform work while avoiding the hazards,
- Performance of functions in compliance with MSP's procedures and safety rules,
- Ability to comply with OSHA requirements and other safety requirements as necessary,
- Use of personal protective equipment while on site.

(4) Essential Technical Skills

- Knowledge of single phase electrical metering,
- Knowledge of electric distribution safety procedures,
- Knowledge of the meter panel and socket layout for the metering conditions of this class of meter work,
- Ability to identify energy diversion or tampering related to this class of meter work,
- Ability to install and remove damaged and undamaged meters,
- Ability to read meters used in this class,

- Ability to properly use tools appropriate to this class of work,

- Ability to connect meter communications external to the meter panel,

- Ability to initialize meter communication modules not utilizing Type 2 optical ports and meter configuration software.

(5) How Essential Technical and Safety Skills Are Determined.

- MSPs develop and implement a program to train workers to perform Class 1 meter work safely and properly, including a minimum 40 hours of on-the-job training with a qualified Class 1, or higher, meter worker,

- Employees are certified by the licensed Meter Service Provider, based on demonstrated ability to perform Class 1 safety skills and essential technical skills, prior experience, completion of the training program referenced above, or a combination of these three methods,

- A Class 1 Meter Worker who has not performed the work equivalent to that identified above for six months or more must be re-certified before performing Class 1 meter work.

b. State Class 2 Qualification.

(1) Metering Types and Voltages. Workers with a MSP Class 2 qualification are permitted to perform work on all Class 1 meter types, as well as:

- Polyphase, safety socket and standard socket-based meters,

- 300V phase-to-phase maximum and up to 600V, polyphase, safety socket or socket-based,

- K-base, and transformer rated meters with internal diagnostics,

- Meters with communication wiring routed inside the panel, and work can be in and around energized circuits.

(2) Work to be Performed

- A Class 2 Meter Worker may work in and around energized circuits, as permitted by the procedures and safety rules of the licensed Meter Service Provider,

- In addition to performing the work of a Class 1 Meter Worker, a Class 2 Meter Worker may install, remove and replace polyphase, 120/240 volt or 120/208 volt, self-contained meters in safety socket and standard socket based metering equipment. A Class 2 worker may operate test-bypass facilities in self-contained safety sockets, and install communication wiring inside the panel. On panels without test-bypass facilities, a Class 2 worker may not remove or install polyphase meters without first disconnecting the customer load,

- A Class 2 Meter Worker may install, remove and replace all meters consistent with the above, including transformer-rated meters with internal diagnostics,

- A Class 2 Meter Worker may operate test switches, but may not install, alter, maintain or replace wiring between the meter, test switch, test block and associated equipment.

(3) Safety Skills

- All of the safety skills required for Class 1 Meter Workers,

- Electrical safety knowledge and work skills appropriate for three-phase metering up to 600V

phase-to-phase, including the ability to identify and refer to a Class 3 meter installer services above 600V phase-to-phase prior to performing work in the service equipment, or if voltage rating is not labeled, at the time of initial voltage check,

- Ability to operate test-bypass facilities or test blocks in a self-contained safety socket.

(4) Essential Technical Skills

- All of the essential technical skills required for Class 1 Meter Workers,

- Knowledge needed for up to 600V polyphase service and the forms and voltages applicable to Class 2 Meter Work

- Ability to route communication wiring to accommodate meter communications,

- Ability to understand, interpret, identify and take appropriate actions based upon built-in diagnostics of solid state meters,

- Ability to perform phase rotation assessments,

- Ability to work with transformer-rated meters and operate test switches and test blocks,

- Ability to test meters in locations other than in the meter socket using semi-automatic meter test equipment.

(5) How Essential Technical and Safety Skills Are Determined

- MSPs develop and implement a program to train their workers to perform Class 2 meter work safely and properly,

- Employees are certified by the licensed Meter Service Provider based on demonstrated ability to perform Class 2 safety skills and essential technical skills, prior

experience, completion of the training program referenced above, or a combination of these three methods,

- A Class 2 Meter Worker who has not performed metering work equivalent to that described above for six months or more must be re-certified prior to performing Class 2 meter work.

(6) Additional Experience Requirements. Minimum experience requirements for certification as a Class 2 Meter Worker:

- One year on-the-job training working alongside a Class 2 or higher Meter Worker and successful completion of the MSP training program described above, or

- A two- or four-year degree in a related subject, and four months on-the-job training working alongside a Class 2 or higher Meter Worker, and successful completion of the MSP training program, or

- Attainment of journeyman-level electrician, journeyman-level electric metering worker, or journeyman-level line worker, and successful completion of the MSP training program.

c. State Class 3 Qualification

(1) Metering Types and Voltages. Workers with a MSP Class 3 qualification are permitted to perform work on all meter types in Classes 1 and 2. Class 3 work also includes:

- Metering up to 600V, with transformer-rated meters and with primary and secondary voltages less than 600V, and

- Metering systems with instrument transformer primary side voltages over 600V,

- Metering systems with communication wiring behind the panel, and work can be in and around energized circuits.

(2) Work to be Performed

- A Class 3 Meter Worker may work in and around energized circuits, as permitted by the procedures and safety rules of the licensed Meter Service Provider,

- In addition to performing Class 1 and 2 Meter Work, a Class 3 Meter Worker may install, remove and replace meters consistent with the description provided above,

- A Class 3 Meter Worker may operate test switches and test blocks, perform in-field meter accuracy tests and calibrations, and perform all types of meter maintenance and troubleshooting,

- A Class 3 Meter Worker may program and verify internal programs and software in solid state meters.

(3) Safety Skills

- All of the safety skills required for Class 1 and Class 2 Meter Workers,

- Ability to conform processes to additional electricity hazards, unique customer environments, and complexities associated with metering switchboards, testing meters and maintaining meters.

(4) Essential Technical Skills

- All of the essential technical skills required for Class 1 and Class 2 Meter Workers,

- Ability to perform work on metering switchboards,

- Knowledge of the operating characteristics of metering transformers and the ability to operate test switches and test blocks,

- Ability to perform calibration, repair, retrofit, troubleshooting, and data collection from electric meters,

- Ability to install, maintain and program advanced metering technologies, including time-of-use (TOU) meters, interval meters, real time pricing, remote meter communication, and load control devices.

(5) How Essential Technical and Safety Skills Are Determined

- MSPs develop and implement a program to train workers to perform Class 3 meter work safely and properly,

- Employees are certified by the test process outlined below,

- Individuals seeking to perform open access meter services as a Class 3 Meter Worker must successfully pass written and practical (demonstrative) tests. The tests can be created by the MSP, or may be standardized tests created by a professional association, state or federal government,

- Prerequisites for the tests:
  - Minimum of one year experience as a Class 2 Meter Worker, including six (6) months on the job training with a Class 3 Meter Worker, or
  - Employment for one year as a journeyman metering employee, or
  - Employment as a qualified individual (Master Electrician) certified by the state's Electrical Contractors Board.

(6) Testing and Re-Certification Requirements

- Successful completion of the Class 3 Meter Worker Test permits a Class 3 Meter Worker to perform that class of open access meter work in the state,

- A meter worker who has not performed metering work equivalent to that described above for six months or more must be re-certified prior to performing that class of meter work.

(7) Continuing Education. A Class 3 Meter Worker must participate annually in at least twelve (12) hours of continuing education. The content of this training shall be determined by the licensed Meter Service Provider and shall address standards of practice and related safety issues.

B. FUNCTIONAL PROTOCOLS FOR METER SERVICE PROVIDERS (MSPS). This section provides additional information on how MSPs may be able to meet the licensing requirements.

1. Worker Qualifications

a. Meter Service Providers shall employ meter workers who are trained and qualified according to the provisions of this Standards & Protocols Manual and have a training program form new employees.

b. Meter Service Providers shall establish a program that appropriately informs all employees and, as a minimum, specifies the following:

(1) Company procedures and safety rules for meter workers.

(2) Occupational Health and Safety Administration (OSHA) regulations that apply to each class of meter worker.

(3) Protective clothing requirements that apply to each task or to each class of meter worker.

(4) Knowledge requirements for safety hazards, metering, meter installations, and electrical distribution for each class of meter worker.

(5) Meters that may be worked on by each class of meter worker.

(6) Tools that are appropriate to each class of meter worker.

(7) A method of establishing the continuing education requirements for Class 3 Meter Workers.

2. Hardware and Software Systems. Meter Service Providers shall have hardware and software systems in place to record work order information, obtain meter readings (during installation, removal and maintenance), perform on-site validation, and send work order and meter readings to a Supplier in a format mutually agreed upon

between the MSP and the Supplier. However, if a MSP does not have a contractual relationship with the Supplier, the exchange of meter data shall be done *via* the appropriate SET protocol.

3. System Documentation & Operating Procedures. Meter Service Providers shall have documentation of the systems and standard operating procedures used to conduct activities for which they have been licensed.

4. System Security. Meter Service Providers shall have security systems in place to protect their physical plant and customer data from unauthorized physical or electronic entry or tampering.

5. Employee Uniform Requirements. Meter Service Provider employees shall have uniforms and shall carry identification that prominently displays the name of the employee and the company, and includes documentation that the MSP is licensed by the applicable regulatory authority. Such uniforms, prominently displayed identification, and documentation shall be required any time an MSP employee enters a customer's premises.

6. Comprehensive General Liability Insurance. Meter Service Providers shall carry a minimum of $1 million in comprehensive general liability insurance and shall provide evidence of such insurance to the applicable regulatory authority for initial licensing, and annually thereafter.

METER READING SERVICE

If meter reading services are deemed competitive by the applicable regulatory authority, then competitive meter reading services will be performed by a Meter Reading Service Provider (MRSP). MRSP services will be the responsibility of the party indicated in the customer's enrollment and/or account maintenance. These services include both cumulative and interval metering, and both direct and remote meter reading. Meter Reading Service Providers shall perform meter safety inspections and reporting, where applicable, as detailed below. A MRSP shall provide service in accordance with the applicable regulatory authority regulations and all standards and protocols found herein.

While the entities providing metering services are defined herein as three separate entities (Meter Service Providers, Meter Reading Service Providers, and Meter Data Management Agents), the functions and services can be provided by one entity for both regulatory and business purposes, such that the meter reading services and meter provider services can be performed by a MDMA.

A. METER READER SERVICE PROVIDER (MRSP) SERVICES. Meter data shall

be read and transferred pursuant to the following standards:

1. For residential and small commercial customers, meters will be read periodically in a manner consistent with tariff requirements and retail settlement requirements unless the MRSP is confronted by circumstances beyond its control, including:

a. severe weather;

b. an animal that presents risk of injury; or

c. any other circumstance which makes it unreasonably difficult to read the meter.

2. Upon agreement with the MRSP and the Supplier, the customer may read his own meter for billing purposes provided that:

a. The MRSP clearly indicates to the MDMA and all other affected market participants that the meter was read by the customer.

b. The meter usage data is treated as estimated, to be confirmed and adjusted as necessary upon a MRSP site visit.

3. In response to a substantive customer inquiry, the MRSP will arrange for a meter read within five (5) business days.

4. The MRSP will provide raw meter reads to the MDMA in a format mutually agreed upon between the MDMA and MRSP.

5. The MRSP will perform the error checks during meter reading, as applicable, as described in the Validation, Editing and Estimation section below.

6. Within five (5) business days after installation of a remotely read meter, the MRSP must check that the meter and meter reading system are working properly.

B. METER READING WORKER QUALIFICATIONS

1. General Qualifications. The following meter reading worker qualifications are set forth as criteria for a meter reading worker to perform retail access meter reading services.

a. Any meter reading worker performing meter reading services on behalf of a MRSP shall have sufficient training to exercise due care in performing these functions.

b. A MRSP employee who performs meter reading work is required to have appropriate identification, indicating the worker's employer and the class of meter work the worker is qualified to perform. This identification must be carried by the employee whenever doing meter reading work in the field.

2. Demonstration of Job Skill Requirements

a. Knowledge of applicable metering types and voltages.

b. Work to be Performed. Meter reading workers must be able to accurately visually read meters and/or read meters *via* a form of electronic communication using a computerized device as applicable.

c. Safety Skills

(1) Knowledge of electricity hazards and ability to perform work while avoiding the hazards;

(2) Performance of functions in compliance with MRSP's procedures and safety rules;

(3) Ability to comply with applicable OSHA requirements and other safety requirements as necessary; and

(4) Use of personal protective equipment while on site.

d. Essential Technical Skills

(1) General knowledge of electrical watthour metering;

(2) Knowledge of electric distribution safety procedures;

(3) Ability to identify energy diversion or tampering;

(4) Ability to identify damaged and undamaged meters;

(5) Ability to read meters; and

(6) Ability to properly use tools appropriate to this work.

e. How Essential Technical and Safety Skills Are Determined

(1) MRSPs will develop and implement a program to train their workers to perform meter reading work safely and properly, including on the job training with a qualified meter reading worker.

(2) Employees will be certified by their employers based on prior experience and/or the use of the training program referenced above.

C. FUNCTIONAL LICENSING REQUIREMENTS FOR METER READING SERVICE PROVIDERS. If an entity is approved to operate as a MRSP in another state whose standards meet or exceed the applicable regulatory authority's standards, the entity must provide documentation of such approval. Otherwise, a prospective MRSP must provide documentation that it meets the requirements below. Suppliers that wish to receive a license for the MRSP service, but plan to provide such services only through a subcontractor, shall demonstrate how they will ensure that its subcontractor(s) will meet the functional requirements.

1. The MRSP has trained and qualified employees and a training program for new employees.

2. The MRSP has hardware and software systems in place to obtain meter readings, perform on-site validation, and send readings to an MDMA in a format mutually agreed upon between the MRSP and MDMA. However, if a MRSP does not have a contractual relationship with the MDMA, the exchange of meter data shall be done *via* the appropriate SET protocol.

3. The MRSP has documentation of its systems and standard operating procedures.

4. The MRSP has security systems in place to protect its systems from unauthorized physical or electronic entry or tampering.

5. The MRSP's employees have uniforms and identification, including documentation that the MRSP is approved by the applicable regulatory authority. Such prominently displayed identification and documentation are required any time an MRSP

enters a customer's property.

6. All MRSPs must carry a minimum of $1 million in general liability insurance and provide evidence of such insurance to obtain a license from the applicable regulatory authority.

METER DATA MANAGEMENT SERVICE

Competitive meter data management services, as defined herein, will be provided by a Meter Data Management Agent (MDMA). MDMA services may include both interval and cumulative data. MDMA services will be the responsibility of the party indicated in the customer's enrollment and/or account maintenance transactions. A MDMA shall provide service in accordance with applicable regulatory authority regulations and all standards and protocols found herein.

A. METER DATA MANAGEMENT AGENT (MDMA) SERVICES. MDMA obligations include, but are not limited to, the following:

1. The MDMA shall maintain the following data:

a. Meter reads;

b. Meter usage;

c. Meter characteristics;

d. Service Delivery Point Identifier, if available; and

e. Usage history provided by previous provider.

2. The MDMA shall validate, edit, and estimate data, if necessary, pursuant to the rules of validation, editing and estimation as described herein. The MDMA shall also perform data adjustments and reframing as required.

3. The MDMA shall provide meter reads to the Supplier, Utility and other market participants as necessary, using the applicable SET protocol.

4. The Supplier, Billing Party where applicable, Scheduling Coordinator, Independent System Operator (ISO) or functional equivalent, and Utility shall have access to meter usage data.

5. The MDMA is required to keep the most recent thirteen (13) months of customer usage data for each meter. This requirement entails the storage of both

raw and validated, edited and estimated data. Such data shall be readily available for thirteen (13) months and accessible for an additional period of twenty-four (24) months. Such data must be released on request to the customer or, if authorized by the customer, to any Supplier. If the entire thirteen (13) months of usage history is not available, the applicable number of months available shall be provided.

B. FUNCTIONAL LICENSING REQUIREMENTS FOR METER DATA MANAGEMENT AGENTS

1. If an entity is approved to operate as an MDMA in another state whose standards meet or exceed the applicable regulatory authority's standards, the entity must provide documentation of such approval. Otherwise, a prospective MDMA must provide the applicable regulatory authority with documentation that it meets the requirements below.

a. The MDMA utilizes trained and qualified employees and a training program for new employees.

b. The MDMA has hardware and software systems in place to receive meter readings; perform customer association, validation, editing, and estimation; and provide readings in the appropriate SET protocol.

c. The MDMA has documentation of its systems and standard operating procedures.

d. The MDMA has security systems in place to protect its systems from unauthorized physical or electronic entry or tampering.

e. The MDMA has a disaster recovery plan to restore service to a level that meets normal business requirements from a minor disruption, such as computer hardware failure, within four (4) hours and a major disruption, such as a natural disaster, within 24 hours.

2. All prospective MDMAs must perform a one-time data exchange test as follows below. Documentation of successful completion shall be retained and presented to the applicable regulatory authority 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 SET protocol.

3. All MDMAs must carry a minimum of $1 million in general liability insurance and provide evidence of such insurance to obtain a license from the applicable regulatory authority.

4. Suppliers that wish to receive a license for MDMA 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.

METER PRODUCTS

A. SUMMARY OF METER PRODUCT STANDARDS. This Section describes the Meter Product standards, the process by which Meter Products 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 comply with the national standards identified below.

This Section is used in conjunction with American National Standards Institute Standards ANSI C12.1 and C12.20 to address issues that are not currently addressed in the ANSI C12.1 and C12.20 Standards. Some of these issues are: 1) duplication of the field electrical and environmental conditions is necessary to assure safety, 2) not all components of a meter product are required to be included in the meter product during certification testing, 3) reporting of certification tests is not based on all meter products tested, 4) no certification rejection criteria is provided for declaration of success or failure upon completion of certification tests. ANSI C12.1 and C12.20 are living documents and may in the future incorporate some of these issues. The recommendation is that as new versions of ANSI C12.1 and C12.20 are released, they should be reviewed and replace portions of this document as deemed appropriate.

1. Meter Service: A meter service includes the following equipment:

Meter product: A device which measures, calculates, records and/or communicates energy consumption data for the purpose of determining the financial obligation for an entity consuming energy, including any optional circuit boards, devices, or modules enclosed within the meter cover.

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 potential

transformers (PTs), as well as communication components, are considered meter equipment.

2. ANSI C12 Standards. The following ANSI C12 Standards apply (where applicable) to meter products and equipment used in the state.

a. ANSI C12.1 – 1995 Code for Electricity Metering. This standard establishes acceptable performance criteria for new types of ac watt-hour meters, demand meters, demand registers, pulse devices, instrument transformers, and auxiliary devices. It states acceptable in-service performance levels for meters and devices used in revenue metering.

b. 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.

c. (c) ANSI C12.7 – 1993, Watt-hour Meter Sockets (where applicable). 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.

d. ANSI C12.8 - 1981 (R1997), Test Blocks and Cabinets for Installation of Self-Contained A-Based Meters. This standard covers the dimensions and functions of test blocks and cabinets used with self-contained A-base watt-hour meters. General requirements are specified for: spacings, temperature rise, assembly bolts, connectors, test clips, barriers, and mounting holes. Test-block dimensions and configurations, as well as test-block cabinets, are also included.

e. ANSI C12.9 - 1993, Test Switches for Transformer-Rated Meters. This standard covers the dimensions and functions of meter test switches used with transformer-rated watt-hour meters 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, spacings, and dimensions.

f. 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.

g. ANSI C12.11 – 1987 (R1993) and ANSI C57.13, Instrument

Transformers. These standards govern the design and use of instrument transformers. Such transformers should comply as appropriate with these standards covering requirements for transformers, conformance and field testing of them, and the grounding of their secondaries and cases.

h. 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 includes the following features of this register: 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 are not covered in this standard but can be found in ANSI C12.1-1988 [1] and ANSI C12.10-1987 [2] (the date of the standards when C12.13 was approved). Both standards (C12.1 and C12.10) have been updated and the references in C12.13 may not match with the updated standards.

i. ANSI C12.18 – 1996, Type 2 Optical Port (Optical Port Only). This standard details the criteria required for communications with an electronic metering device by another device via an optional port. Application of this standard only applies to meters with an ANSI C12.18 Type 2 Optical Port and requires compliance only with the hardware design and requirements of the type 2 optical port. The data protocol requirements of this standard are not mandatory.

j. ANSI C12.20 – 1998, 0.2% & 0.5% Accuracy Class Meters. This standard gives requirements for accuracy performance, under various conditions, for accuracy class 0.2 and 0.5. Standard also calls for additional testing outlined in ANSI C12.1 - 1995.

k. I.1.10 IEC 61000-4-4 or ANSI C37.90.1 – 1989, Fast Transient Test. (Manufacturer's choice as to which standard to apply). This standard relates to the immunity requirements and test methods for electrical and electronic equipment to repetitive electrical fast transients. Additionally defines ranges of test levels and establishes test procedures. The object of this standard is to establish a common and reproducible basis for evaluating the performance of electrical and electronic equipment when subjected to repetitive fast transients (bursts), on supply, signal and control ports. The test is intended to demonstrate the immunity of electrical and electronic equipment when subjected to types of transient disturbances such as those originating from switching transients (interruption of inductive loads, relay contact bounce, etc.). The standard defines: test voltage waveform; range of test levels; test equipment; test set-up; test procedure.

l. ANSI Z1.4 – 1993, Sampling Procedures and Tables for Inspection. This standard, which corresponds to MIL-STD-105, establishes sampling

plans and procedures for inspection by attributes. Its tables and procedures are completely compatible with MIL-STD-105. It is also interchangeable with BSR/ASQC Z1.9-19XX for variable inspection.

m. ANSI Z1.9 –1993, Sampling Procedures and Tables for Inspection. This standard, establishing sampling plans and procedures for inspection by variables, corresponds to the military standard MIL-STD-414 and is interchangeable with ISO/DIS 3951. It contains tables and procedures of MIL-STD-414, suitably modified to achieve correspondence with ISO/DIS 3951 and matching with MIL-STD-105 and BSR/ASQC Z1.4-19XX.

3. EEI Handbook for Electricity Metering, Ninth Edition (1992). A reference handbook that includes information on electricity metering theory, applications, accuracy and safety.

4. National Electrical Code (NEC 1996). The purpose of this Code is the practical safeguarding of persons and property from hazards arising from the use of electricity.

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

6. Additional Requirements

a. Output contacts if provided on a metering device shall be either Form “A” or form “C”. Form “C” is required if the output contacts are mechanical. The purpose of a mechanical form “C” contact closure is to provide a means to verify the operation of the contacts by checking for “bounce” or defective closure of the switch.

b. Meter products and equipment in use currently by any Utility in the state will continue to be valid for use for the length of their commercial life, assuming they generate the billing parameters required by the marketplace in a timely and appropriate fashion. Nothing in these standards is to be construed so as to obviate the continued use or procurement of existing devices and systems in the future. The Utilties shall provide a list of models purchased within the last five years that are currently in use and which meet marketplace requirements. These models should be posted on the applicable regulatory authority website with models which are self-certified by the manufacturers and approved by the applicable regulatory authority.

c. The meter or associated equipment shall provide a visual display indicating energy consumption to the customer. A standardized data interface shall be available to provide total energy consumption at the meter (a visual display is

adequate).

7. Certification Testing Requirements

a. General

(1) Meter manufacturers shall conduct the tests specified in the Table of Tests below in adequate facilities. An adequate facility is a facility that has access to the necessary equipment and competent personnel to perform the testing requirements specified in this document.

(2) Meter manufacturers shall complete performance testing 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 meet the certification testing requirements as stated in this section.

(3) Meter manufacturers shall provide (if requested) a certified test report 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. The manufacturer, at its discretion, may charge a nominal fee for the reproduction of the certified test report.

(4) Meter Products or metering equipment may be installed before the tests, as outlined in this section, are completed successfully.

(5) Meter Products selected for certification testing shall be representative of production run Meter Products.

(6) The following tests shall be conducted in sequence, not necessarily in this order, using the same Meter Products selected as specified in the table below: Insulation, Voltage Interruptions, Effect of High Voltage Line Surges, Effect of Fast Transient/Burst, Effect of Electrostatic Discharge (ESD), Effect of Operating Temperature, Effect of Relative Humidity, and ANSI C37.90.1 or IEC 61000-4-4 (Surge Withstand). The other tests required by ANSI C12.1 and C12.20 may be done either in parallel or in sequence with the same Meter Products or a separate group of Meter Products. However, with the understanding that the same Meter Products must be used for all test procedures within each ANSI-numbered or FCC-numbered test.

(7) Meter Products selected for testing shall be kept for one year after the conclusion of testing. These test Meter Products shall be made available during this period to any purchaser for inspection, if requested.

(8) Meter Products which fail during the test shall not be repaired or tested further, but can be analyzed to identify the cause of failure.

(9) When the test Meter Products fail to meet these testing requirements and after any correction is made on the new test Meter Products, all tests shall be re-started with the new test Meter Products.

(10) If requested by the purchaser, the manufacturer shall notify the purchaser of the certification test schedule for purchaser's test witnessing.

(11) If more than a minimum number of Meter Products are certification tested, the test results shall be based on and reported for all Meter Products tested.

b. 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.

(3) Signs of physical damage as a result of a test procedure.

(4) The occurrence of a loss of data or other unacceptable mode of operation for the Meter Product as a consequence of a test procedure.

(5) Failures of either hardware, firmware or software, or a combination thereof.

c. Meter Type Certification Rejection Criteria. The meter type certification rejection will be based on ANSI 12.1 and 12.20 criteria.

d. Test Setup

(1) The Meter Product shall be connected to its normal operating supply voltage with a fully charged power failure backup system and shall be

energized throughout the duration of the test procedures, unless otherwise stated.

(2) Before testing commences, if necessary, the Meter Product shall be energized for a reasonable period at room temperature for stress relief.

e. Test A1 - Sunlight Interference Test. The Sunlight Interference Test only needs to be performed on electromechanical type meters with an electronic module (retrofit). This test verifies the Meter Product accuracy and full functional operations under direct sun light.

(1) The meter cover shall be removed during this test.

(2) The Meter Product shall be exposed to an incandescent light source (Lab Test).

(3) The incandescent light source, Smith Vector #710 or equivalent, shall be used to simulate the sunlight. The incandescent light shall be 600 watt and 3,200° K blackbody radiation as a minimum.

(4) The Meter Product shall be exposed to the incandescent light source for a minimum of five minutes for each position of the incandescent light source.

(5) The incandescent light source shall be pointed directly toward the Meter Product and positioned at a maximum direct distance of 19 inches from the center of the meter rotor shaft as follows:

- Twelve positions around the meter base.
- Eight positions at a 45° angle from the meter base,
- One position at a perpendicular to the face of the meter.

(6) Verify the Meter Product operations and report the direct and remote meter reads before and after each incandescent light exposure.

(7) Table Of Tests In ANSI C12.1 & C12.20

	Tests performed in series (.)	Descriptions of Certification Tests	ANSI C12.1	ANSI C12.20
1		No Load	Test #1	Test #1
2		Starting Load	Test #2	Test #2
3		Load Performance	Test #3	Test #3
4		Effect of Variation of Power Factor	Test #4	Test #4
5		Effect of Variation of Voltage	Test #5	Test #5
6		Effect of Variation of Frequency	Test #6	Test #6
7		Equality of Current Circuits	Test #7	Test #7
8		Internal Meter Losses	Test #8	Test #8
9		Temperature Rise	Test #9	Test #9
10		Effect of Register Friction	Test #10	Not
11		Effect of Internal Heating	Test #11	Test #10
12		Effect of Polyphase Loading	Not	Test #11
13		Effect of Tilt	Test #12	Not
14		Stability of Performance	Test #13	Not
15		Independence of Elements	Test #14	Not
16	✓	Insulation	Test #15	Test #12
17	✓	Voltage Interruptions	Test #16	Test #13
18	✓	Effect of High Voltage Line Surges	Test #17	Test #14
19		Effect of External Magnetic Field	Test #18	Test #15
20		Effect of Variation of Ambient Temperature	Test #19	Test #16
21		Effect of Temporary Overloads	Test #20	Test #17
22		Effect of Current Surges in Ground	Test #21	Test #18
23		Effect of Superimposed Signals	Test #22	Test #19
24		Effect of Voltage Variation-secondary Time	Test #23	Test #20
25		Effect of Variation of Amb. Temp.-second.	Test #24	Test #21
26	✓	Electrical Fast Transient/Burst	Test #25	Test #22
27		Effect of Radio Frequency Interference	Test #26	Test #23
28		Radio Frequency Conducted and Radiated	Test #27	Test #24
29	✓	Effect of Electrostatic Discharge (ESD)	Test #28	Test #25
30		Effect of Storage Temperature	Test #29	Test #26
31	✓	Effect of Operating Temperature	Test #30	Test #27
32	✓	Effect of Relative Humidity	Test #31	Test #28
33		Mechanical Shock	Test #32	Test #29
34		Transportation Drop	Test #33	Test #30
35		Mechanical Vibration	Test #34	Test #31
36		Transportation Vibration	Test #35	Test #32
37		Weather Simulation	Test #36	Test #33
38		Salt-spray	Test #37	Test #34
39		Rain tightness	Test #38	Test #35
40		Test #A1: Sunlight Interference	Not yet	Not yet
41	✓	Test #A2: ANSI C37.90.1, Surge Withstand or IEC 61000-4-4	Not yet included	Not yet included

(8) Competitive Meter Product Registration and Self-Certification Process. All competitive meter products shall be "self-certified" by the meter product manufacturers using the certified testing requirements mentioned above. Manufacturers shall file with the applicable regulatory authority their meter type self-certification document to state that their meter type meets the applicable regulatory authority certification testing requirements.

Self-Certification Process. The certification testing requirements are listed above. In order to certify their meter products, meter manufacturers must follow the steps listed below:

- Assemble documentation: Manufacturers must provide (1) either a cover letter, or a copy of the actual certified test report; the cover letter or test report must document the tests conducted, including results, and must state that the test report is available and will be provided to any meter purchaser on request; (2) a completed competitive Meter Product self-certification form, including a list of the meter products being certified as compliant with the certification testing requirements, and (3) a completed declaration form.

- Mail the documentation and completed declaration form to the applicable regulatory authority.

- Upon review of the application materials, the applicable regulatory authority will advise the meter manufacturer of the results and post the product information on the applicable regulatory authority website, if approved.

METER DATA PERFORMANCE AND TIMELINESS STANDARDS

Meter data must be read, validated, edited, and estimated in a timely fashion to meet market requirements for billing and settlement. The following standards apply to any Meter Reader Service Provider and Meter Data Management Agent (Metering Party), whether provided competitively or by the Utility. Performance must be determined consistently and fairly for all Metering Parties. In some states, the Meter Reader Service Provider and the Meter Data Management Agent are not affiliated with each other, or with the customer's Supplier, and each may work directly with the customer; while in other states, these functions are performed by subcontractors to the Supplier. Note that "business days" are defined as Monday through Friday, excluding federal banking holidays.

A. INTERVAL DATA TIMELINESS STANDARDS

1. 80% of all usage data must be available by the end of the first business day (11:59 p.m. prevailing time at the meter location) after the scheduled reading date of the meter.

2. 90% of all usage data must be available by the end of the second business day (11:59 p.m. prevailing time at the meter location) after the scheduled reading date of the meter.

3. 100% of all usage data must be available at the end of the fifth business day (11:59 p.m. prevailing time at the meter location) of the scheduled reading date of the meter.

4. No more than 10% of all interval data will be estimated per month.

B. CUMULATIVE DATA TIMELINESS STANDARDS

1. 85% of all cumulative meter readings must be available by 5:00 p.m. (prevailing time at the meter location) on the first business day after the scheduled meter reading date.

2. 95% must be available by 5:00 p.m. (prevailing time at the meter location) on the second business day after the scheduled meter reading date.

3. 100% must be available by 5:00 p.m. (prevailing time at the meter location) on the fifth business day after the scheduled meter reading date.

C. PERFORMANCE METRICS CALCULATIONS

1. Timeliness and percent estimated shall be measured based on the first data delivered by the Metering Party after the meter read date for each meter. Timeliness shall be based on the time stamp when the SET is transmitted by the Metering Party.

2. When there is no direct contractual relationship between an MDMA and MRSP, the MRSP shall provide meter reading data to the MDMA in a timely fashion to allow the MDMA to meet these performance requirements.

3. The first billing cycle by a Metering Party following a Supplier switch is to be exempt from the timeliness and estimation performance standards.

4. In the event of meter failure where the meter is not accurately recording usage and the Metering Party has no control over the meter, the estimated data is to be exempt from the timeliness and estimation performance standards provided that: (1) a manual reading has verified that the meter has failed and there is no problem with the remote reading technology; and (2) the exemption cannot occur for an account more than once in a twelve (12) month period.

METER USAGE DATA REQUIREMENTS

A. VALIDATION, EDITING, AND ESTIMATION REQUIREMENTS. The following requirements apply to any party that is performing meter usage data validation, editing, and estimation, and providing such data to other parties.

1. Data Transfer

a. Data is always sent in complete billing periods. Note that for the billing period containing the initial read for an account, the billing period starts with the initial read, and for the final read of an account, the billing period ends with the final read.

b. Each value has an associated Date/Time field as a time stamp. All time stamps (both for data points and sets of data) will be reported in GMT.

c. If the Utility account number or the Supplier account number changes during the billing period, the account numbers reported with meter data should be those that apply at the end of the billing period.

d. Interval data should be sent as kWh during each interval, not as kW, and as kVARh instead of kVAR. For interval lengths other than sixty (60) minutes, the interval length needs to be combined with the kWh value to get the customer's demand level (kW). Only usage values, not cumulative meter readings, are required for interval data.

e. The time stated for a recording interval shall be the end of the interval.

f. For cumulative data, data must include: the start-of-period date and time, usage, end-of-period date and time, and end-of-period reading; the start-of-period reading is optional. Exceptions, which include start of accounts and meter changes for the start-of-period reading, must be sent.

g. For time-of-use (TOU) data, TOU usage values, and demand values, where required, must be provided, but the cumulative meter reading is only

required for total consumption.

h. Metered data for a close of account (final read) will be provided within five (5) business days from receipt of notification that the account was closed.

i. Estimated usage must be identified as "Estimated" in the SET transactions, but the reason for estimation does not need to be provided as part of the SET. However, if requested, the party which estimated the data must be able to explain the reason for estimation and the estimation method used.

j. When changes affecting the service delivery point occur (*e.g.*, a meter change), the data for each meter must be reported as a separate set of data within a single SET corresponding to the customer's billing period.

k. If the Supplier or the Utility changes a customer's meter to provide different capabilities, there may be a mix of interval and non-interval data during a billing period

l. If changes occur in rate requirements (*e.g.*, kVAR or demand metering), a new type of data does not become part of billing until it is available for a full month, so the Metering Party can choose whether to include partial month data. TOU data would not be required to be reported until it is available for a complete billing period. The Utility's or the Supplier's rate change would occur on the next billing cycle, when new data requirements are involved; when data is no longer needed, the Utility would notify the Metering Party effective at the end of a billing cycle, and ignore unneeded data pertaining to later dates.

m. If an abnormal condition is discovered that requires the meter to be replaced, a data gap can occur between a meter malfunction or removal of a hazardous condition, and replacement of the meter with a functionally equivalent meter, thus requiring estimation of the missing data. When an advanced meter is temporarily replaced with a cumulative meter due to hazardous conditions, to be replaced later by a functional equivalent of the original meter, the period of estimated data when the cumulative meter is in place should be reported with the old meter number.

n. As soon as an old meter (one that is being replaced) is out of its socket, the new Metering Party is responsible for the data starting with the time interval after the one that contains the time when the old meter is pulled out. If both the old and new metering parties are agents for the same Supplier, each Metering Party may send its own data for the periods for which it is responsible, but the Supplier remains responsible for ensuring the continuity and simultaneous posting of the complete set of data if multiple metering parties are separately posting partial-month

data.

2. Totalization. Totalization is considered the responsibility of the Billing Party, thus neither the MRSP nor the MDMA is responsible for totalization.

3. Unmetered Usage. For unmetered service, load points such as streetlights are grouped by contract, although there are variations by customer. Aggregating lights as much as possible simplifies the transfer of usage data between market participants and its input into billing systems. The following apply:

a. For unmetered service, one usage value will be posted for an account, which may encompass multiple load points.

b. If a change in an account's inventory of load points is discovered for a past billing period, the entire amount of usage for the account should be reported as an adjustment (not just the amount of the correction).

c. If an account goes from unmetered to metered service, metered usage would start with the first full billing cycle. The ability of a customer to convert from metered to unmetered service has not been determined, but if this were to occur, metered usage would be reported only if the account is metered for the full billing cycle.

d. Fixed loads, to which connected load charges are applicable, would not be sent by a Metering Party.

e. The Supplier determines how the account is billed for unmetered accounts.

4. Adjustments to Previously Transmitted Data. Resending and/or adjustment of previously transmitted data arises from data maintenance activities (*e.g.*, response to customer inquiries, needs to restore data files, and response to problems with posted data), and meter maintenance activities (*e.g.*, adjustments as improved information becomes available due to discovery of incorrect reads, crossed meters, "cut-in-flat" situations, non-registering meters, slow or fast meters, incorrect multipliers, etc.). The following apply:

a. When corrections are made to previously sent data, the original SET is first cancelled. A new SET of "original" data is then transmitted.

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

corrected data points). If the corrected data represents actual usage, it does not need to be flagged; if the corrected data represents estimated usage, it must be flagged as estimated. When resending or correcting data, each billing cycle for the affected meter should be in a distinct data set in the SET. Only the data for the affected billing cycle and meter needs to be resent, but the entire billing cycle needs to be resent, for exactly the same period that was originally sent. (For example, if the meter was originally read late for the end of a billing cycle, the resent data should cover the period that was actually reported, rather than for what the billing cycle should have been.)

c. In the case of "crossed meters", in which meter numbers have been incorrectly reported for sets of usage data, the original SET should be cancelled, and a new SET transmitted that correctly reports the data, Service Delivery Point Identifier, meter identifier, and account identifier.

d. The Metering Party should make corrected data available to the original recipients in a timely manner no matter when a correction is discovered, due to the possibility of impacts on bill adjustments, estimations, unaccounted-for-energy (UFE), and revenue assurance. It is then up to the recipients to determine how to respond.

5. Reframing. Reframing refers to resending of data for a corrected time period, usually when a customer's start-up or turn-off occurs. When data are "reframed", all affected months must be cancelled and resent. The following scenarios illustrate this principle in handling the anticipated situations other than routine reporting of usage data:

a. Scenario #1 (Start date specified, data posted, start date changed to a later date before read date).

(1) The Metering Party is contacted and told that service for a given customer and meter is starting at a given date/time.

(2) The Metering Party obtains the start meter read.

(3) On the meter's scheduled read date, the Metering Party reads the meter. The Metering Party sends the interval data for the meter from the start date/time through the scheduled read date.

(4) The Metering Party is notified that the customer actually moved in later than originally specified.

(5) The Metering Party cancels the original SET and resends the customer's interval data; the data now goes from the new (later) start date

to the scheduled read date.

April 28	Metering Party notified of new service starting 5/1
May 1 - Original Start Date	Metering Party starts reading interval data
May 3 - New Start Date	
May 5 - Scheduled Meter Read	Metering Party sends interval data for 5/1 - 5/4
May 7	Metering Party notified service actually started 5/3
May 9	Metering Party cancels the original SET and resends interval data for 5/3 - 5/4

b. Scenario #2 (Start date specified, data sent, start date changed to a date after the read date).

(1) The Metering Party is contacted and told that service for a given customer and meter is starting at a given date/time.

(2) The Metering Party obtains the start meter read.

(3) On the meter's scheduled read date, the Metering Party reads the meter. The Metering Party sends the interval data for the meter from the start date/time through the scheduled read date.

(4) The Metering Party 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 Metering Party cancels the original SET and sends data starting on 5/7 as if it were original data.

April 28	Metering Party notified of new service starting 5/1
May 1 - Original Start Date	Metering Party starts reading interval data
May 5 - Scheduled Meter Read	Metering Party sends interval data for 5/1 - 5/4
May 7 - New Start Date	
May 8	Metering Party notified service actually started 5/7
May 10	Metering Party cancels the original SET and sends interval data for period starting 5/7

c. Scenario #3 (Start date specified, data sent, start date changed to an earlier date).

(1) The Metering Party is contacted and told that service for a given customer and meter is starting at a given date/time.

(2) The Metering Party obtains the start meter read.

(3) On the meter's scheduled read date, the Metering Party reads the meter. The Metering Party sends the interval data for the meter from the start date/time through the scheduled read date.

(4) The Metering Party is notified that the customer actually moved in earlier than originally specified.

(5) The Metering Party cancels the original SET. If the Metering Party has interval data for the new period (from the new start date), the Metering Party resends the data from the new start date to the read date. Note that this may include more than one billing period of data. If interval data is not available for the earlier time, the Metering Party estimates the data and resends it in a similar fashion. In this case, the estimated intervals are marked as estimated.

April 28	Metering Party notified of new service starting 5/3
May 1 - New Start Date	
May 3 - Original Start Date	Metering Party starts reading interval data
May 5 - Scheduled Meter Read	Metering Party sends interval data for 5/3 - 5/4
May 8	Metering Party notified service actually started 5/1
May 10	Metering Party cancels the original SET and resends data from 5/1 - 5/4

d. Scenario #4 (Stop date specified, data sent, stop date changed to a later date).

(1) The Metering Party is contacted and told that service for a given customer and meter is ending at a given date/time.

(2) The Metering Party obtains the stop meter read.

(3) The Metering Party sends the meter's data from its last read schedule through the stop read.

(4) The Metering Party is notified that the customer actually moved out later than originally specified.

(5) The Metering Party cancels the original SET. If possible, the Metering Party obtains interval data for the additional time period the customer occupied the premise. If not, the Metering Party estimates the data. The Metering Party resends the data from the meter's last scheduled read day through the new stop date/time. Note that this may include more than one billing cycle, depending on when the Metering Party is notified of the change in stop dates.

April 28	Metering Party notified service ending 5/1
May 1 - Original Stop Date	Metering Party obtains final meter read
May 2	Metering Party sends final data through 5/1
May 5 - New Stop Date	
May 8	Metering Party notified service actually stopped 5/5
May 10	Metering Party cancels the original SET and obtains or estimates data through 5/5 and resends data through 5/5.

e. Scenario #5 (Stop date specified, data sent, stop date changed to an earlier date after meter's scheduled read date).

(1) The Metering Party is contacted and told that service for a given customer and meter is ending at a given date/time.

(2) The Metering Party obtains the stop meter read.

(3) The Metering Party sends the meter's data from its last read schedule through the stop read.

(4) The Metering Party is notified that the customer actually moved out earlier than originally specified.

(5) The Metering Party cancels the original SET and resends the meter's data from the its last scheduled read date through the new stop date/time.

April 28	Metering Party notified service ending 5/3
May 1 - New Stop Date	
May 3 - Original Stop Date	Metering Party obtains final meter read
May 4	Metering Party sends final data through 5/3
May 8	Metering Party notified service actually stopped 5/1
May 10	Metering Party cancels the original SET and resends data through 5/1

f. Scenario #6 (Stop date specified, data sent, stop date changed to an earlier date before the previous read date).

(1) The Metering Party is contacted and told that service for a given customer and meter is ending at a given date/time.

(2) The Metering Party obtains the stop meter read.

(3) The Metering Party sends the meter's data from its last read schedule through the stop read.

(4) The Metering Party 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 Metering Party cancels the original SET and resends the meter's data from the previous scheduled read date that is before the new end date through the new end date.

April 28	Metering Party notified service ending 5/5
May 1 - Scheduled Read Date	Metering Party reads and sends interval data through 4/30
May 5 - Original Stop Date	Metering Party obtains final meter read
May 6	Metering Party sends final data through 5/5
May 8	Metering Party notified service actually stopped 4/29
May 10	Metering Party cancels the original SET and resends data through 4/29

6. Curtailments

a. The Metering Party must be informed by the appropriate party of curtailments that apply to both historical data and to current billing periods.

b. Historical data from a period of curtailment should not be used to validate or estimate current data when no curtailment occurred. Similarly, normal estimation rules may not be appropriate if data needs to be estimated for a curtailment period.

c. If a customer's entire billing period needs estimation, and data

is used from last year, and that period last year was in curtailment, the estimated data will be low, but will still pass validation, editing, and estimation rules. The customer can potentially be under-billed.

d. Note that the Metering Party still has the option to manually check the data for reasonableness and adjust with appropriate documentation.

7. Change in Metering Parties at Time of Meter Install/Changeout. Typically, there is a small gap in time from the meter removal until the new meter installation, however there are occasions when there is a large gap in time, specifically on large customers where hardware changes are done at the time of install. When there also is a change of Metering Party at the same time, the original Metering Party is responsible for the full interval in which the meter was pulled (this may involve estimating that interval). The new Metering Party is responsible for all data starting with the first complete interval after the original meter was pulled. (Example: Originating meter is pulled at 9:50am. The new Metering Party will be responsible for posting data beginning at the 10:15am interval, *e.g.*, 10:01 to 10:15. The original Metering Party will be responsible for the 10:00am interval, *e.g.*, 9:46 to 10:00.)

B. DATA QUALITY. The standards contained herein are intended to ensure the timely delivery and storage of billing and settlement quality data. Any party providing metering services (Utilities, MDMAs, MRSPs, and/or MSPs) shall take all necessary steps to ensure the following standards are met.

1. Meter Data Standards

a. Accuracy For All Meters:

(1) Meter clocks may be maintained on any time zone but must be synchronized to within +/- three (3) minutes of the National Institute of Standards and Technology (NIST) Atomic clock.

(2) Usage data will be accurate unless otherwise indicated. Data known to be inaccurate or missing will be estimated and flagged as estimated. If a customer reads his own meter, it must be specified as estimated.

b. Retention and Format For Validated Meter Reading Data:

(1) Meter reading data shall be retained such that it is readily available for thirteen (13) months and shall be accessible for an additional twenty-four (24) months.

(2) Meter reading data will be provided *via* the appropriate SET protocol.

2. Data Validation, Editing, and Estimation. At this time, there are no national standards for data validation, editing, and estimation. Until such time as a national standard is developed, the following requirements provide the market with standard principles for performing the Validation, Editing, and Estimation (VEE) process. These requirements ensure that all Metering Parties utilize similar checks and estimation methodologies. A detailed procedural guide is included as Exhibit 1 as an example of one methodology that is fully compliant with the principles below. Other procedures, including the Utility's legacy methodology, should be allowed insofar as they satisfy the requirements defined herein.

The Metering Party shall retain documentation of procedures used for presentation during an audit. Additionally, the Metering Party shall provide the procedures upon request to a customer, Supplier, Utility, or the applicable regulatory authority. In the event the applicable regulatory authority determines one detailed set of procedures be adopted, the procedures in Exhibit 1 could be utilized as the statewide standard; however, the parties should be able to determine how they will validate, edit, and estimate as long as the following principles are met.

a. The following data validation tests are required for kWh and kVARh (if used in billing) interval data validation:

(1) Time check of meter reading device/system: compare to a standard that is traceable to a national standard time source. Accuracy tolerances shall be +/- 3 minutes. Such check should occur before data collection for the day begins. This check shall be performed by the MRSP.

(2) Time check of meter: compare to a traceable standard. Accuracy tolerances shall be +/- 3 minutes. This check shall be performed by the MRSP.

(3) Pulse overflow check: verify that number of pulses does not exceed maximum. This check shall be performed by the MDMA.

(4) Sum check: verify that sum of intervals equals total consumption. This check shall be performed by the MDMA.

(5) Spike check: check for usage spikes. This check shall be performed by the MDMA.

(6) High/low check: check for too low or too high

consumption. Check should utilize average daily usage for billing month one year prior.. This check shall be performed by the MDMA.

(7) Meter identification check: verify meter identification number when reading. This check shall be performed by the MRSP.

b. The following tests are required for monthly data validation:

(1) High/low usage check: check for too low or too high consumption. Check should utilize consumption for billing month one year prior. This check shall be performed by the MDMA.

(2) High/low demand check (applies to demand readings only): check for too low or too high demand. Check should utilize demand readings for billing month one year prior. This check shall be performed by the MDMA.

(3) Time-of-use check (applies to TOU data only): verify that sum of usage by time period equals total consumption. This check shall be performed by the MDMA.

(4) Time check of meter where applicable (TOU meters): compare to a traceable standard. Accuracy tolerances shall be +/- 3 minutes. This check shall be performed by the MRSP.

(5) Zero consumption for active meters: validate data if no consumption shown for active meter. This check shall be performed by either the MRSP or the MDMA.

(6) Meter reading dial/digit quantity: verify that number of dials/digits reported is same as number of dials/digits on meter display. This check shall be performed by the MRSP.

(7) Dial decimal quantity: verify number of decimal places displayed on meter is correct (applicable for on-site reads only). This check shall be performed by the MRSP.

(8) Meter identification: verify meter identification number when reading. This check shall be performed by the MRSP.

c. Irregular Usage Customers. An irregular usage customer is one whose usage pattern does not follow normal usage patterns and consistently fails the spike check, kVARh check, or high/low usage check. A customer may be identified as an irregular usage customer by its Metering Party if:

(1) The customer data fails the standard validation check for three consecutive months and the Metering Party verifies that the data represents the actual customer usage or the Metering Party is notified by the customer's Supplier or previous Metering Party of the irregular usage pattern.

(2) If a customer has been identified as an irregular usage customer, the Metering Party must notify both the Supplier and the Utility. Standard validation tests may then be modified based on the customer's usage pattern.

d. Data Estimation. Data estimation is required when an actual meter read is not available or data has been determined to be invalid. The following data estimation rules are required for cumulative data estimation:

(1) Use historical data for same customer at the same location; use rate class data if historical data for same customer is unavailable.

e. Data Estimation. Data estimation is required when an actual meter read is not available or data has been determined to be invalid. The following data estimation rules are required for interval data estimation:

(1) When less than two (2) hours is missing: use straight-line interpolation.

(2) When more than two (2) hours is missing: use historical data for same customer at same location; use rate class data if historical data for same customer is unavailable

C. DATA EXCHANGE. The following standards and protocols are a baseline, or minimum set, necessary to compete in the marketplace. They are intended to facilitate data exchange between parties and minimize transaction and development costs. Contracted or affiliated parties may, at their discretion, utilize additional, alternative data exchange standards and protocols for communication internally or among themselves.

1. Meter Identifier System. 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.

a. A uniform meter number standard will be utilized in the state. The meter number is compliant with ANSI C12.10 and compatible with the American Electric Power (AEP) Number standard.

b. The meter identifier system shall apply to all new meters and meters as they are re-numbered.

c. A new meter number shall be provided to the Utility by the Supplier, or a subcontractor of the aforementioned parties, as an account maintenance transaction or as part of the enrollment process.

d. The meter number is intended to be used in all applicable data exchanges and shall be labeled on the meter in accordance with ANSI C12.10 standards. The meter number is not required to be stored in the meter itself.

e. The meter number format is: AABYYYYYYYYYZZZZZ

(1) where AA is the meter test code;

(2) where B is an identifier for the meter manufacturer;

(3) where YYYYYYYYY is the manufacturer's serial number; and

(4) where ZZZZZ is a user-defined field, such as the Department of Energy's ID number for the Utility service territory in which the meter is initially installed or a number which indicates meter ownership.

2. Service Delivery Point ID (SDP ID). The Service Delivery Point Identifier (SDP ID) is a unique, permanent, and non-intelligent number, used to facilitate communications in an unbundled electric market.

a. Format: 1-0-xxxxx-yyy…yy

(1) where 1-0 is reserved for future use;

(2) where xxxxx is the Utility's Department of Energy ID number;

(3) where yyy…yy is a 29 character Utility-assigned number that is permanent and unique within the Utility service territory.

b. A Service Delivery Point Identifier (SDP ID) will be assigned by the Utility as follows:

(1) The SDP ID for all meter sockets will be assigned as part of the Enrollment process the first time a customer switches to a Supplier. For multi-metered sites, each meter socket shall have its own SDP ID.

(2) SDP IDs for unmetered accounts will be assigned as part of the Enrollment process the first time a customer switches to a Supplier. For unmetered accounts:

(i) SDP IDs will be assigned at the contract level.

(ii) SDP IDs established for unmetered contracts live past the contract term.

(iii) An unmetered SDP ID shall be retired if that SDP ID becomes metered or upon removal of the equipment to which the ID refers.

c. The SDP ID shall be included in all account or meter related transactions.

Meter Product
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 applicable regulatory authority website. The attached list must be provided in the format shown below:

Manufacturer Name	Model Number

(use as many rows as necessary)

Meter Product
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 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 _____, At _____.
(date) (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:

Requirements for Validating, Editing, and Estimating Monthly and Interval Data in Open Access

Section A: NV Interval Data VEE Rules (Revision 1.0)

1. Introduction

This section defines the interval data validation, editing, and estimation techniques required to participate in the Nevada market as an MDMA.

2. Required Data Validation Checks

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

These rules apply to both kWh and kVARh data, depending on the data required by the meter's tariff(s). If data is provided for informational purposes only (not used for billing purposes), validation is not required. Data that has not gone through the validation process is raw data.

General MDMA and MSP business practices should ensure that the meter is programmed correctly for the required revenue data and that the MDMA and MRSP systems are set up to accurately maintain information such as interval size, meter constants, and what quantity is recorded by what channel. These VEE rules do not require or describe how the MDMA or MRSP verifies that the meter is programmed correctly.

All validation checks must be run. Failure of one check does not preclude the MDMA from performing other validation checks.

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 been verified
- Verified data - data that failed at least one of the required validation checks but was determined to represent actual usage
- Estimated - data that has been calculated based on standard estimation rules because the raw data was not valid

The following validation checks are required for interval kWh and kVARh data. They are described in section 3 of this document:

Requirements for Validating, Editing, and Estimating Monthly and Interval Data in Open Access

Check	Purpose
Time check of meter reading device/system	Check for the following: • time drift of meter reading device/system outside CPUC standard
Meter identification check	Check for the following: • meter ID was reported correctly • meter has not been changed out • data is being reported for the correct meter
Time check of meter	Check for the following: • time drift of meter clock outside CPUC standard
Pulse Overflow check	Check for the following: • improper scaling factor in meter • improperly sized transformer • hardware problem
Test Mode check	Check for the following: • Data collected when meter was in test mode that represents test load rather than actual usage
Sum check	Check for the following in combination meter/recorder installations: • Crossed channels between meter and recorder • pulse relay problems Check for the following for all installations: • invalid PT and CT ratios, • invalid meter constants
Spike check	Check for the following for all installations: • 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.
kVARh check (for kWh data only if corresponding kVARh data available)	Check for the following: • kWh channels are correctly mapped to kVARh channel • meter is operating correctly

Check	Purpose
High/Low Usage check	Check for the following in all installations: • dropped phases • inaccurate meter constants • energy diversion • fast/slow meters Also check for the following in combination meter/recorder installations: erratic pulse input to recorder

3. Interval data collection and validation rules

If interval data is read more often than required for billing, checks need to be performed at different times in the process. Some must be done as the data is read from the meter; some can be done anytime between when the data is collected from the meter and the end of the cycle, and others have to be done on a billing period basis at the end of the billing cycle. They are broken out that way in this description.

3.1. Time check of meter reading device/system ensures that the collection device is synchronized to the national time standard before data collection begins.

3.2. Collect data

3.3. As data is collected

3.3.1. Check meter identification – verify that the meter's identification matches what is expected.

3.3.2. 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.

How to do Time Tolerance check on meter

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 months, the meter must be physically inspected/tested.

How to do Time Tolerance check on data

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 75 minutes, prorate the data using one of the algorithms in Attachment 1, Section 1.
2) If the meter time was off by more than 75 minutes, the data must be estimated.

3.4. Either as data is collected or prior to publishing on MDMA Server

3.4.1. 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.

3.4.2. Perform Test Mode check

If the MDMA determines the meter was in test mode, the MDMA 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 .

3.4.3. 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 < = two meter multipliers, the data passes the sum check. (meter multiplier = CTR x VTR, where CTR is current transformer ratio and VTR is voltage transformer ratio)
- 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. See Attachment 1, Section 2.1 for more information.

   (c) Redo the sum check, taking into account missing or incomplete intervals. See Attachment 1, Section 2.2 for more information.

(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.

3.4.4. 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 the 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 ((highest peak - third highest peak)/third highest peak) < = 1.8, the interval passes the spike check.
- If ((highest peak - third highest peak)/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 on Irregular Usage Customers for additional information.

3.4.5. If interval kVARh data is available, perform kVARh Check

The kVARh check is performed to identify intervals where reactive load (kVARh) 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 kVARh are used for billing. If kVARh 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 kVARh Check

1) If multiple kWh channels map to a single kVARh channel, or multiple kVARh 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 kVARh interval.

Pass/Fail Criteria

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

If data fails the kVARh Check

1) Several optional steps may be taken to resolve the kVARh 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 kVARh 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 kVARh 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.

3.5. On the billing cycle for the meter

3.5.1. 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 |(historical daily average - this month's daily average)| < = 0.25* historical daily average, the data passes the high/low usage check.
- If |(historical daily average - this month's daily average)| > 0.25* 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 on Irregular Usage Customers for additional information.

3.6. After all validation checks have been performed and required data has been estimated, rerun validation checks to ensure reasonableness of estimates. It is not required to re-run the sum check for data obtained from solid state meters; it is required to re-run the sum check for data obtained from recorders. If data fails validation after estimation and good meter readings are available, the estimated intervals must be scaled based on the meter readings as described in Section 4.3 of Attachment 1. Note that this may be done as part of the estimation process prior to re-running the check. If data fails validation after estimation, it needs to be manually verified for reasonableness.

[NOTE: The MAVI group had a last minute disagreement on this issue and will re-address it. An update on this section will be provided. The rule outlining the manual inspection of data is too vague and still needs to be outlined and addressed.]

3.7. 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 MDMA must record the estimation algorithm used. Interval data estimation algorithms include:

- less than 2 hours (4.1)
- greater than 2 hours (4.2) – not scaled based on usage
- greater than 2 hours (4.2) – scaled based on usage
- time-drifted intervals prorated (Attachment 1, Section 1.1)
- time-drifted intervals prorated (Attachment 1, Section 1.2)
- intervals adjusted (4.3)
- intervals manually estimated (4.2.8)
- intervals estimated due to meter interval programmed incorrectly (4.4)
- load profile template used (4.2.7)

3.8. Irregular Usage Customers

An irregular usage customer is one whose usage pattern does not follow normal usage patterns and consistently fails the spike check, kVARh check, or high/low usage check. An MDMA 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 MDMA verifies that the data represents the actual customer usage, OR

2) MDMA is notified by the customer's DC or previous MDMA of the irregular usage pattern.

The data used to identify an irregular usage customer could be data collected by the MDMA, or historical data provided by the previous DC or MDMA. An MDMA may modify the spike check and/or high/low usage check, and skip the kVARh check if an irregular usage customer consistently fails the check. The MDMA must notify both the customer's DC and EDU 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 MDMA would perform to verify that this is the customer's normal usage pattern. An MDMA may use a variation of the spike check or high/low usage check based on the actual usage pattern. Note that the MDMA 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 (+/- 25%), 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 MDMA 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.

4. Interval Data Estimation Rules

Estimate intervals needing estimation using the following estimation rules

4.1. If section of data needing estimation is 2 hours or less in length, use point-to-point linear interpolation to estimate the data. If the interval on either side of the data needing estimation is a power failure interval, the MDMA has the option to use the power failure interval or the previous or past 'good' interval at their discretion based on reasonableness of the data.

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.

4.2. 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 daytype (i.e., weekday, weekend, or holiday) as the day that needs estimation.

- A standard list of holidays will 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. The holidays used are the following:
  - New Years Day
  - Presidents Day
  - Memorial Day
  - Independence Day
  - Labor Day
  - Nevada Day
  - Veterans Day
  - Thanksgiving Day
  - Christmas Day

  If the MDMA is aware the customer's actual usage on a standard holiday is different than an authorized holiday stated in the above, the MDMA may use 'Like Days' estimation in place of holidays. Also, if the MDMA is aware of the customer observing a holiday that is not an authorized holiday as stated above, the MDMA may use 'Holidays' estimation in place of 'Like Days'. If these optional estimation techniques are not utilized, and the accuracy of the billing determinants are materially affected as a result, the MDMA shall re-estimate the data.

- 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 90 days prior to the day needing estimation and from the current billing period may be used for estimation. They are to be used in the following order:

  1. Current billing period

  2. Up to 90 days prior to the day needing 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.

4.2.1. 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 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 and 90 days of historical data, use it as the daily profile.

4) If no same weekdays are available in the current billing period 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 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 and 90 days of historical data, use it as the daily profile.

4.2.2. 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. See Attachment 1, Section 3 for more information.

4.2.3. 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 ??? 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).

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

4.3. 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 MDMA 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

4.4. Interval in meter doesn't match tariff or settlement requirements

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

Requirements for Validating, Editing, and Estimating Monthly and Interval Data in Open Access

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*20) and 40 kWh (0.5*20 + 30). This is similar to the prorating technique discussed in Attachment 1 Section 1.1. The meter must be reprogrammed to the correct interval.

Requirements for Validating, Editing, and Estimating Monthly and Interval Data in Open Access

Section B: NV Monthly Data VEE Rules (Revision 1.0)

1. Introduction

This document defines the data validation, editing, and estimation techniques required to participate in the Nevada market as an MDMA or MRSP for monthly data. Monthly data includes consumption, demand, and Time-of-Use (TOU) consumption and demand..

2. Required data validation checks

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

The following checks are required for monthly data validation for kWh and kW data. Similar checks would apply to kVARh and kVAR data if those values are required.

Check	Purpose
Time check of meter reading device/system (applies to devices/systems collecting TOU data only)	Check for the following: • time drift of meter reading device/system outside CPUC standard
Time check of meter (applies to meters collecting TOU data only)	Check for the following: • time drift of meter clock outside CPUC standard
High/low usage check	Check for the following: • misread • fast/slow meter • broken meter • incorrect multipliers • energy diversion • dropped phases
High/low demand check (applies to demand readings only)	Check for the following: • misread • fast/slow meter • broken meter • incorrect multipliers • energy diversion • dropped phases

Check	Purpose
Time-of-use check (applies to TOU data only)	Check for the following: • misread • fast/slow meter • broken meter • incorrect multipliers • energy diversion • dropped phases
Zero consumption for active meters	Check for the following: • energy diversion • meter doesn't register
Usage for inactive meters	Check for the following: unauthorized usage at a site for which there is no customer with financial responsibility
Number of dials on meter	Check for the following: • wrong meter • misread
Dial decimal quantity	Check for the following: • wrong meter • misread
Meter identification	Check for the following: • that the meter ID was reported correctly • the meter has not been changed out • the data is being reported for the correct meter

3. Rules for Monthly Data Validation Check

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.

3.1. 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

3.2. 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.

3.2.1. 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.

3.2.2. 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 MDMA 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 may optionally be reset.

3.2.3. 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.

3.3. High/Low Usage

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

3.3.1. Method based on historical data

3.3.1.1. 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:

ADU = (current billing read - previous billing read)/(# 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.

3.3.1.2. Calculate the historical ADU

3.3.1.2.1. 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.

3.3.1.2.2. 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.

3.3.1.2.3. 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.

3.3.1.3. 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.

3.3.1.4. 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.

3.3.1.5. 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.

3.3.2. 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.

3.3.2.1. 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:

3.3.2.1.1. At the end of the reading day, for each good meter read (open account, billed, between 27-33 days & ADU = < 100), perform the following calculations to determine an ADU for the billing period:

1. Calculate ADU (= KWH/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

3.3.2.1.2. Determine which range of usage (high, medium or low) the current ADU should be grouped with by comparing current ADU to yesterdays ADU Low and High Range Factors (Reference 3.3.2.1.3 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 is in 3.3.2.1.2. step 1.

3. Otherwise, add the current ADU to the ADU high range following the same format in 3.3.2.1.2. step 1.

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

3.3.2.1.3.1. Sum together the ADU values for each geographic area

3.3.2.1.3.2. Calculate the mean for the total ADU (= Sum of Current ADU / total meters)

3.3.2.1.3.3. Calculate the standard deviation for the total

3.3.2.1.3.4. 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)

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

3.3.2.1.4.1. After each meter's current billing period's (ADU) is grouped in 3 Ranges (Low, Medium, and High) as specified in 3.3.2.1.2, 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

3.3.2.1.5. 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:
HRF = 1 + {(2.8X Modified Standard Deviation X Number of meters) / (Sum of Current month's ADU)}

Low Range Factor Formula:
LRF = 1 - {(3.5 X Modified Standard Deviation X Number of meters) / (Sum of Current month's ADU)}

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

3.3.2.2.1. Determine the usage from the preceding billing month and the preceding billing reading for the customer and site.

3.3.2.2.2. Calculate low limit for this month's usage by multiplying the preceding month's usage by the low range factor determined above.

3.3.2.2.3. Calculate high limit for this month's usage by multiplying the preceding month's usage by the high range factor determined above.

3.3.2.2.4. 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

High Range Value: 400kwh X 1.115 HRF* = 446
Low Range Value: 400kwh 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.

3.3.2.2.5. 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.

3.3.2.2.6. 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.

3.4. High/Low Demand

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

3.4.1. Determine the peak demand for this billing period.

3.4.2. Determine the historical peak demand.

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

3.4.2.2. 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 3.3.1.2.2 to determine same billing period last year.)

3.4.2.3. 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.

3.4.3. 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.

3.4.4. 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.

3.4.5. 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.

3.5. TOU Usage

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

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

3.5.2. Compare the calculated total kWh with the current total kWh 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) +/- 2. If the current total kWh read from the meter was between 488 and 502 inclusive, the data would pass the check. If the current total kWh read from the meter was less than 488 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 < = the total kWh.

3.6. Zero Consumption for Active Meters

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

3.6.1. 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.

3.6.2. If the usage is greater than 0, the data passes the zero consumption check.

3.6.3. 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

3.6.4. 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.

3.7. 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.

3.7.1. Determine the number of digits in the meter reading.

3.7.2. 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.

3.7.3. 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.

3.8. 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.

3.8.1. 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.

3.8.2. 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.

3.9. 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 MDMA must investigate why the meter is different than indicated by their records and resolve the inconsistency

2. If the meter is red 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 MDMA must investigate why the meter is different than indicated by their records and resolve the inconsistency.

3.10. 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 MDMA if the MDMA 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 MDMA is notified by the customer's previous MDMA.

The data used to determine a customer is an irregular usage customer could be data collected by the MDMA, or historical data provided by the previous DC or MDMA. A DC may notify the MDMA 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 MDMA 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 MDMA must notify both the customer's DC and EDU 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 MDMA 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.

4. Monthly Data Estimation Rules

Note that the MDMA must record the estimation algorithm used for each data element that is estimated. The MDMA 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 (MDMA must document when this is used)

4.1. 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.

4.1.1. Method 1 - Based on Historical Usage

4.1.1.1. Calculate ADU to be applied

4.1.1.1.1. 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 3.3.1.2.2 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.

4.1.1.1.2. 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.

4.1.1.1.3. 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 MDMA must document how the data is estimated.

4.1.1.2. 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.

4.1.1.3. 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.

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

4.1.2.1. For the residential meter population (i.e., same geographic area and customer class), utilize the following determinants as determined in 3.3.2:

- ADU Low Range Factor (3.3.2.1.3.4)
- ADU High Range Factor (3.3.2.1.3.4)
- Low Range Modified Mean Factor (3.3.2.1.4.1)
- Medium Range Modified Mean Factor (3.3.2.1.4.1)

- High Range Modified Mean Factor (3.3.2.1.4.1)

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

4.1.2.3. Calculate the modified ADU for a specific meter by multiplying last month's ADU (from step 4.1.2.2) by yesterday's medium range modified mean factor (above) for that geographical area.

4.1.2.4. 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.

4.1.2.5. Multiply the prior ADU by the modified mean factor determined in 4.1.2.4. This becomes the new estimated ADU.

4.1.2.6. Continue with steps 4.1.1.2, and 4.1.1.3 using the estimated ADU calculated in the preceding step.

4.2. Estimating Demand

4.2.1. 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 3.3.1.2.2 to determine the same billing period last year. In this case, the estimation algorithm is estimation based on previous year's data.

4.2.2. 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

4.2.3. 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)

4.3. 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.

4.3.1. 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.

4.3.1.1. Calculate ADU to be applied

4.3.1.1.1. 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 3.3.1.2.2 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.

4.3.1.1.2. 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.

4.3.1.1.3. 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.

4.3.1.2. 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.

4.3.1.3. 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.

4.4. 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.

4.4.1. 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.

4.4.1.1. 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 3.3.1.2.2 to determine the same billing period last year. In this case, the estimation algorithm is estimation based on previous year's data.

4.4.1.2. 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.

4.4.1.3. 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).

Requirements for Validating, Editing, and Estimating Monthly and Interval Data in Open Access

Attachment 1: Interval Data VEE Technical Methods (Revision 1.0)

This attachment provides technical information for Section 1 (NV Interval Data VEE Rules) of Appendix A.

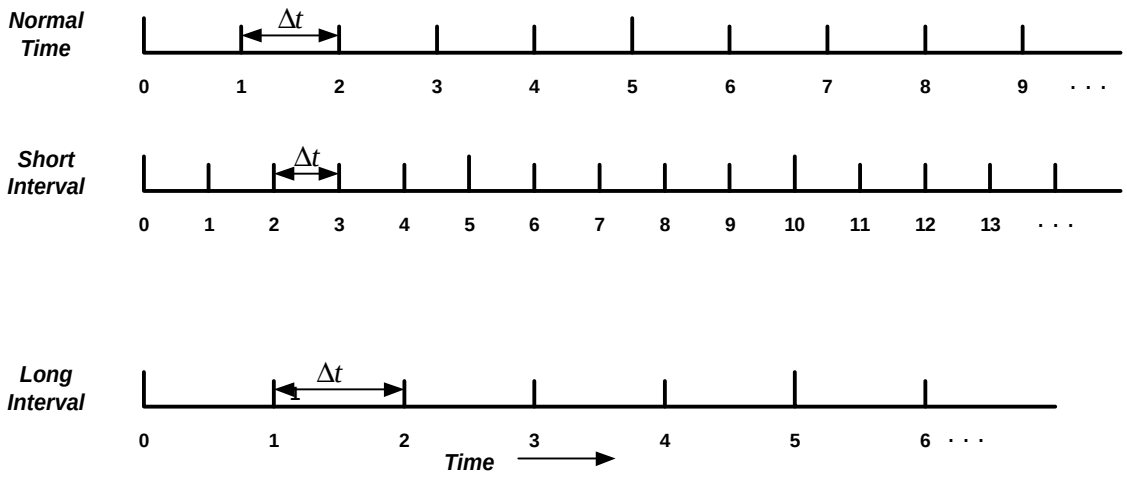
4.1. Prorating Time Drifted Data

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.

After the data is pro-rated, it is considered good data. If estimation is needed within the billing period, the pro-rated intervals can be used to estimate.

4.1.1. 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, $\mathbf{T_0}$ {for example, the last meter read} and that the meter is now being read at a read time, $\mathbf{T_r}$. For each case above, assume that the meter

reading system reads at the same time. The elapsed time is given by

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

The elapsed time for the shorter interval case is given by

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

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

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

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 NV 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:

$$\textbf{Total Drift Time For Short Intervals } TD_s = |\Delta T_e - \Delta T_{es}| = |T_r - T_{ms}|$$

and

$$\textbf{Total Drift Time For Long Intervals } TD_l = |\Delta T_e - \Delta T_{el}| = |T_r - T_{ml}|$$

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:

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

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

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

Two cases are considered.

Case # 1 is when N = Ns = Nl, 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

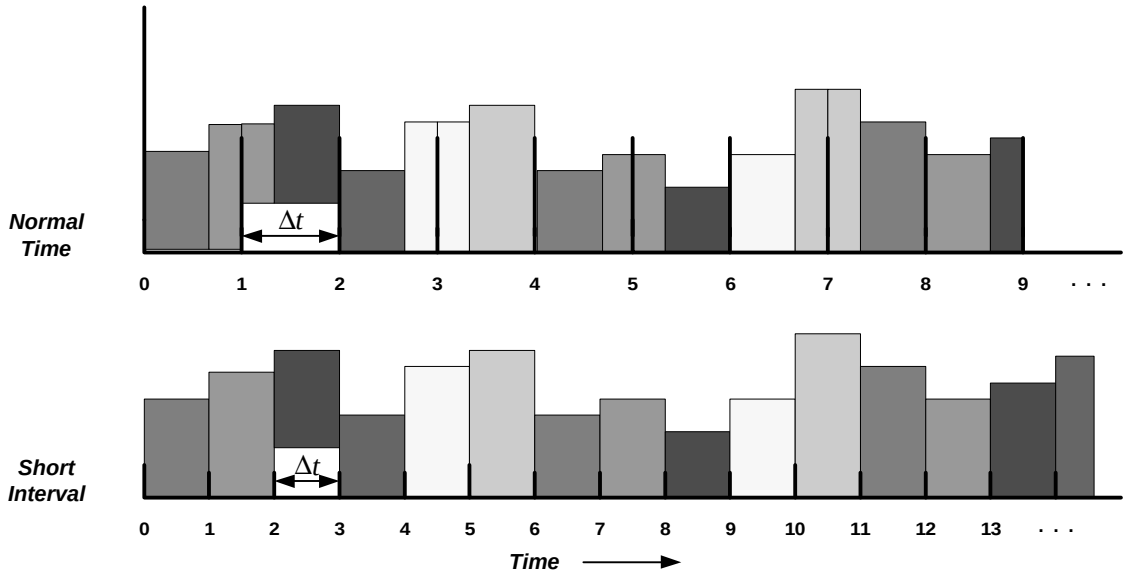
$$\Delta DT_s = TD_s / N$$

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 ≠ Ns or N ≠ Nl 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, Δt + ΔDTl or Δt - ΔDTs. 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**. But this should not be a problem.

4.1.2. 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.

4.2. 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.

4.2.1. Account for Start and End Time Differences

The following technique enables the MDMA 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:

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 min./60 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, the percentage usage is (240*0.50) = 120 kWh.

(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 is equal to 120 meter increments. For a meter multiplier of 80, 120 kWh 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) 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 min./60 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, the percentage usage is (120*0.25) = 30 kWh.

(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 is equal to 30 meter increments. For a meter multiplier of 80, 30 kWh 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.

4.2.2. 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 MDMA 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:

1) Count the number of good intervals in the data stream.

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.

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.)

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.

5) If the difference is < = allowable margin from 1.2.1, the good intervals pass the sum check. The missing or incomplete intervals need to be estimated.

4.3. 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:

1) Determine the total usage for the time period based upon the meter readings.

   Total Usage = ((Stop Reading-Start Reading)*Meter Multiplier)

2) Sum together the valid intervals.

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

4) Sum together the previously estimated intervals.

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

6) Multiply each estimated interval by the scaling factor.

This attachment provides an example of validating and estimating usage based on previous day usage of similar customers. The text is a duplicate of the corresponding sections in the NV Monthly VEE Rules. The numbers to the left of the text correspond to the numbers on the spreadsheet at the end of the attachment.

4.3.1. 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.

Spreadsheet Calculations:

4.3.1.1. 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:

→
Represents the numerical association on the attached spreadsheet calculations. Used for mapping only.

4.3.1.1.1. At the end of the reading day, for each good meter read (open account, billed, between 27-33 days & ADU = < 100), perform the following calculations to determine an ADU for the billing period:

1 →
1. Calculate ADU (= KWH/days in billing period)
2. Add ADU to Sum of Current ADU

2 →
3. Calculate ADU squared
4. Add ADU squared to Sum of Current ADU squared
5. Add 1 to total meters

3 →
6. Calculate last month's ADU

4 →
7. Calculate current ADU times last month's ADU

5 →
8. Calculate last month's ADU squared

4.3.1.1.2. Determine which range of usage (high, medium or low) the current ADU should be grouped with by comparing current ADU to yesterdays ADU Low and High Range Factors (Reference 3.3.2.1.3 for ADU low and high range factor calculation methodology)

6 →

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

Spreadsheet Calculations:

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 3.3.2.1.2. step 1.

3. Otherwise, add the current ADU to the ADU high range following the same format in 3.3.2.1.2. step 1.

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

7 → 4.3.1.1.3.1. Sum together the ADU values for each geographic area

8 → 4.3.1.1.3.2. Calculate the mean for the total ADU (= Sum of Current ADU / total meters)

9 → 4.3.1.1.3.3. Calculate the standard deviation for the total

4.3.1.1.3.4. Calculate the current ADU low and high range factors:

10 → • 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.

11 → • ADU High Range Factor = mean + .43 Standard Deviation

12 → • NOTE: By determining the low & high factors, the Medium Range = (mean - .43 Standard Deviation) to (mean + .43 Standard Deviation)

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

4.3.1.1.4.1. After each meter's current billing period's (ADU) is grouped in 3 Ranges (Low, Medium, and High) as specified in 3.3.2.1.2, the following data are summed up by ADU range and area:

Spreadsheet Calculations:

13 → • Number of customers

14 → • Sum of all last month's ADU

15 → • Sum of all current month's ADU

16 → • Sum of {each last month's ADU times current month's ADU}

17 → • Sum of {all last month's ADU squared} i.e., Square all ADU, then sum them.

18 → • 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:

19 → 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).

20 →

Step 2: Take square root of Step 1

~~3.3.2.1.5.~~4.3.1.1.5. 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.

21 → High Range Factor Formula:
HRF = 1 + {(2.8X Modified Standard Deviation X Number of meters) / (Sum of Current month's ADU)}

Spreadsheet Calculations:

22 → Low Range Factor Formula:
LRF = 1 - {(3.5 X Modified Standard Deviation X Number of meters) / (Sum of Current month's ADU)}

~~3.3.2.2.~~4.3.1.2. As each meter is read, perform the following using the values calculated from the previous meter reading days' data.

23 → 4.3.1.2.1. Determine the usage from the preceding billing month and the preceding billing reading for the customer and site.

24 → 4.3.1.2.2. Calculate low limit for this month's usage by multiplying the preceding month's usage by the low range factor determined above.

25 → 4.3.1.2.3. Calculate high limit for this month's usage by multiplying the preceding month's usage by the high range factor determined above.

26 → 4.3.1.2.4. If the current usage is between the low and high limit calculated in the previous two steps, the data passes the High/Low check.

5.1. Estimating Usage

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

~~4.1.2.1.~~5.1.2.1. For the residential meter population (i.e., same geographic area and customer class), utilize the following determinants as determined in 3.3.2:

- ADU Low Range Factor (3.3.2.1.3.4)
- ADU High Range Factor (3.3.2.1.3.4)
- Low Range Modified Mean Factor (3.3.2.1.4.1)
- Medium Range Modified Mean Factor (3.3.2.1.4.1)
- High Range Modified Mean Factor (3.3.2.1.4.1)

27 → ~~4.1.2.2.~~5.1.2.2. Calculate the ADU from last month's billing period for that customer.

Spreadsheet Calculations:

28 → ~~4.1.2.3.~~5.1.2.3. Calculate the modified ADU for a specific meter by multiplying last month's ADU (from step 4.1.2.2) by yesterday's medium range modified mean factor (above) for that geographical area.

29 → ~~4.1.2.4.~~5.1.2.4. 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.

30 → ~~4.1.2.5.~~5.1.2.5. Multiply the prior ADU by the modified mean factor determined in 4.1.2.4. This becomes the new estimated ADU.

~~4.1.2.6.~~5.1.2.6. Continue with steps 4.1.1.2, and 4.1.1.3 using the estimated ADU calculated in the preceding step.

Requirements for Validating, Editing, and Estimating Monthly and Interval Data in Open Access

Attachment 2: Monthly Data VEE Technical Methods

Spreadsheet Calculations:

of Meters 19
# of Days in Month 30

Meter Number	Current Usage	(1) Current ADU	Last Month Usage	(3) Last Month ADU	Meter Reading	(4) Current ADU * Last Month ADU	(2) Current ADU Squared	(5) Last Month ADU Squared	(6) 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		(7) 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 (12)
High	6.73	or higher

	(13) Meters	(15) Curr ADU	(14) Last mo ADU	(16) Curr * Last Mo ADU	(18) Curr Mo sqrd	(17) Last Mo ADU Sqd
Low	6	22.63	26.93	103.97	87.95	124.33
Medium	7	39.77	35.90	204.26	226.38	191.27
High	6	49.37	45.23	373.40	413.66	349.22

	(19) Modified Mean	(20) Mod Std Deviation	(22) Low Range Factor	(21) High Range Factor
Low	0.84	0.45	0.58	1.33
Medium	1.07	1.17	0.28	1.58
High	1.07	1.70	0.28	1.58

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

(23)
Customer's Last Month's Usage = 200 kWh 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:

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

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

(29)
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.

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)

This document is section VI, exhibit 1 of the CUBR Uniform Business Rules Document, Version 1.1, Dated September 1999. The CUBR Document should be considered in its entirety. See Appendix for disclaimers.

VII. OPERATIONS – NATURAL GAS RETAIL OPERATIONS

This section describes the uniform interfaces between natural gas Utilities and natural gas retail Suppliers. The retail operations for nominations, flowing gas, and storage are specific to natural gas. These processes shall be implemented by all natural gas Utilities uniformly.

A. GAS INDUSTRY STANDARDS BOARD'S STANDARDS. The Gas Industry Standards Board (GISB) has developed and established standards for transportation and storage of natural gas. These standards are mandated by the Federal Energy Regulatory Commission (FERC) on interstate pipelines for the "wholesale" transportation and storage of natural gas and are voluntary for "retail" markets. However, the applicable regulatory authority can mandate the use of applicable existing GISB Standards. Having already undertaken the standardization process for the wholesale natural gas industry, GISB is a viable organization to endeavor to standardize natural gas-specific business operations for the retail market.

1. If the GISB standards are used as business rules and standards in the retail market, then some of the GISB standards will require additions and modifications. Such additions and modifications are not major and can be accomplished by GISB under its normal processes. Examples of the necessary changes include:

a. Until migration to standardization occurs, a unit of measure for therms, ccf and Mcf must be added to the applicable data sets;

b. Utility cycle billing must be recognized. GISB's current bill cycle is monthly from the first of the month. Many Utilities use cycle billing based on the date the meter is read;

c. All of the invoicing or bill standards may not apply when the Utility is billing the Supplier or when the Supplier is billing the customer. For instance, it may not be necessary to include all of the transportation and sales elements set forth in the GISB standard in the Supplier’s bill to a customer;

d. GISB's review process may identify additional transaction types, charge types, and service codes for the retail market. All GISB code values should be reviewed for their applicability; and

e. GISB's Electronic Data Interchange (EDI) Trading Partner Agreement must be revised to reflect the necessary revisions in order to be applicable in the retail market, as illustrated by the CUBR’s model Trading Partner Agreement.

VII. OPERATIONS - RETAIL ELECTRIC SETTLEMENTS

The following describes the key issues regarding the interface between the wholesale and retail electric markets. Regardless of whether a given state or region has developed an ISO, a RTO, a transco, or is simply operating within the existing transmission provider's protocols, certain key aspects of the settlements process can and should be standard around the country.

SCHEDULING COORDINATION

A. SCHEDULING COORDINATION FUNCTIONS. A scheduling coordinator acts as the liaison between the Supplier and the ISO/RTO/transmission provider (or functional equivalent). While the exact functions that the scheduling coordinator performs for the Supplier are subject to individual contractual arrangements, the scheduling coordinator may forecast a Supplier's load obligation, schedule the Supplier's load and supply with the ISO/RTO/transmission provider (or functional equivalent), arrange access to transmission and ancillary services, and bill the Supplier for ISO/RTO/transmission provider (or functional equivalent) charges. A Supplier may act as its own scheduling coordinator, or contract with a third party to provide these services. The following rules discuss the functions relating to scheduling coordination, but do not assign which entity will perform such functions. FERC licensed power marketers providing wholesale services do not have to become a scheduling coordinator unless the wholesale marketer is providing services on behalf of retail suppliers.

B. SCHEDULING COORDINATION ACTIVITIES. The scheduling coordination activities include the following:

1. Paying all applicable charges of the ISO/RTO/transmission provider (or functional equivalent) in accordance with the ISO/RTO (or functional equivalent) tariff;

2. Paying the applicable charges of the Transmission Owner in accordance with the Transmission Owner tariff;

3. Submitting balanced schedules for all entities (*i.e.*, Suppliers) for which it serves as scheduling coordinator, in accordance with the rules and protocols of the ISO/RTO/transmission provider (or functional equivalent);

4. Arranging for or reserving transmission capacity for all entities for which it serves as scheduling coordinator, in accordance with the rules and protocols of the ISO/RTO/transmission provider (or functional equivalent);

5. Coordinating and allocating curtailments and interruptions in load and the altering of schedules under its control at the request of the ISO/RTO/transmission provider (or functional equivalent);

This document is section VII, electricity, of the CUBR Uniform Business Rules Document, Version 1.1, Dated September 1999. The CUBR Document should be considered in its entirety. See Appendix for disclaimers.

6. Scheduling supply deliveries to or from other scheduling coordinators;

7. Scheduling and self-providing or acquiring from the ISO/RTO/transmission provider (or functional equivalent) its defined share of ancillary services, providing, where applicable, bids for ancillary services, congestion management, and imbalance energy;

8. Providing the ISO/RTO (or functional equivalent) with settlement quality meter data, in accordance with the rules and protocols of the ISO/RTO/transmission provider (or functional equivalent). After being verified by the Meter Data Management Agent (MDMA) or functional equivalent, the revenue quality data will be sent to the scheduling coordinator *via* the appropriate SET protocol. The scheduling coordinator's responsibilities, which also can be performed by the Supplier or its agent, will include the following data aggregation activities:

a. Retrieving/receiving the revenue quality meter data from the specified MDMA or functional equivalent;

b. Profiling any data from cumulative meters;

c. Applying Distribution Loss Factors (DLFs) as specified by the native Utility;

d. Applying Transmission Loss Factors for transmission-level meters as defined by the ISO or functional equivalent;

e. Aggregating the usage data by voltage class by time period as defined by the ISO or functional equivalent; and

f. Formatting the data according to the applicable SET protocol.

C. ACCESS TO TRANSMISSION SERVICE.

Access to transmission service is procured by a scheduling coordinator pursuant to the applicable terms of the ISO/RTO/transmission provider (or functional equivalent) tariff and/or the Transmission Owner tariff. The ISO/RTO/transmission provider (or functional equivalent) will maintain a business relationship only with the scheduling coordinator for transmission services.

1. The Transmission Owner will bill the appropriate entity directly for pertinent charges.

D. SCHEDULING COORDINATOR CERTIFICATION. The ISO/RTO/transmission provider (or functional equivalent) only will accept requests for transmission reservations,

balanced schedules of energy, load, and ancillary services from scheduling coordinators which have been certified by the ISO/RTO/transmission provider (or functional equivalent). To become a certified scheduling coordinator, an entity must:

1. Demonstrate to the ISO/RTO/transmission provider's (or functional equivalent's) reasonable satisfaction that it is capable of performing the functions of a scheduling coordinator under the ISO/RTO/transmission provider (or functional equivalent) tariff and that it is capable of complying with the requirements of all appendices and protocols;

2. Identify each entity (including itself if it trades on its own account) it represents and confirm that each entity is an eligible customer;

3. Meet the ISO/RTO/transmission provider's (or functional equivalent's) reasonable financial security criteria; and

4. Meet the ISO/RTO/transmission provider's (or functional equivalent's) metering requirements for each entity it represents, as defined in the ISO/RTO's (or functional equivalent's) tariff, appendices, and protocols.

E. OPERATIONS OF THE SCHEDULING COORDINATOR.

1. Each scheduling coordinator will maintain a 24 hour, seven days per week scheduling center for the purposes of communicating with the ISO/RTO/transmission provider(or functional equivalent) for scheduling purposes and the Control Area Operator (CAO) on a real time basis.

2. Each scheduling coordinator shall, for the duration of the scheduling process and settlement period for which the scheduling coordinator has submitted schedules to the ISO/RTO/transmission provider (or functional equivalent), designate a representative who shall be responsible for operational communications with the ISO/RTO/transmission provider (or functional equivalent) and who shall have sufficient authority to commit and bind the scheduling coordinator.

FORECASTING

Suppliers, or their scheduling coordinators, must have access to the Supplier's individual customer's historical usage data and load profiles to accurately prepare hourly schedules and manage the inherent risks associated with providing retail services.

A. The Customer Information Document includes the requirements for obtaining individual customer historical load data.

B. The Load Profiles section of this Document includes the requirements for obtaining

load profiles for customer classes and subclasses.

LOAD PROFILES

Supplier load profiling, forecasting, and settlement activities require a knowledge of a customer's load. The long-term solution for the retail electricity market is to have interval meters on all customers, to the extent economically feasible, in order to accurately measure a customer's load. Until such time, an interim methodology is necessary to bridge the gap to full interval metering and provide an estimated reflection of a customer's load. In the absence of interval load data, load profiles should be used to allocate and settle differences between the actual energy used by Supplier's customers and the Supplier's deliveries. Thus, load profiles settle important physical and financial properties regarding the population they represent. Extreme care must be taken that the load profiles are accurate and representative of the class of customers they designate. For Day 1, the Utility is expected to be the Load Profiling Agent; however, in the future, other entities may be approved by the appropriate regulatory authority to provide this function.

A. The load profiling method used should be based on sound statistical criteria to control for sampling errors and should be reviewed by all market participants and approved by the appropriate regulatory entity. The detail for such methodology may be found in the Load Research Manual of Association of Edison Illuminating Companies.

B. The load profiling method used by the Load Profiling Agents must be consistent and authorized by the applicable regulatory authority. Consistency allows for the ease of verification and implementation by market participants. Efforts need to be made to develop a sound framework by which all Load Profiling Agent profiling is based.

C. The methodology should be detailed enough for the Supplier to replicate the exact profile using the Load Profiling Agent's data. Suppliers should have access to the validated and edited aggregated load research data used to derive the load profiles.

D. All algorithms and data needed to reproduce the load profiles used for settlement purposes should be made available to Suppliers by the Load Profiling Agent *via* a public website in a downloadable format. Updates to algorithms and data must be posted to a public website, with notices of the updates sent via electronic mail to Suppliers. The information on the website should be date stamped with the date posted to the website and the date created.

E. Dynamic load profiling is the preferred method of load profiling. Other load profiling techniques are not as accurate as they are either based only on historical data or are estimated using a modeling approach. Dynamic load profiling captures the impact of current weather on the customer's electricity consumption. Dynamic load profiles are developed when load research meters are equipped with telemetry. The telemetry data are uploaded and processed, and load profiles are developed on a daily basis. Dynamic load profiles should be

used to determine settlements for energy imbalances.

F. Load profiles should be developed for each Load Profiling Agent's customer segment or customer class or subclass, as dictated by the applicable regulatory authority.

1. Each customer segment or customer class or subclass, as appropriate, should be profiled using a statistically valid sample size of all customers in the service territory to assure the quality of the load profile data.

2. The load sample should include both bundled and unbundled customers, such that a customer is not removed from the load sample when the customer begins to receive service from a Supplier.

G. If dynamic load profiling is used, then hourly load profile data, if available for a customer, should be provided to the Supplier no later than three (3) days after the usage date. The Load Profiling Agent must post their load shape information for each customer segment or customer rate class or subclass to a public website in a downloadable format.

H. Updates to load profile information must be posted to a public website, with notices of the updates sent *via* electronic mail to Suppliers. The information on the website should be date stamped with the date posted to the website and the date created.

I. As long as the same accuracy criteria is met, Suppliers should have the ability to propose alternative load profiles for classes or subclasses of customers. The Supplier should be able to negotiate an arrangement with the Load Profiling Agent to develop and/or implement a new load profile.

LOSSES

A. NOTICE AND UPDATES. Updates to information regarding losses and/or changes to the methodologies discussed herein shall be provided to the Supplier or scheduling coordinator *via* the appropriate SET protocol. Notices of the updates and changes shall be sent *via* electronic mail to the Suppliers and/or scheduling coordinators.

B. TRANSMISSION LOSSES. Transmission losses are the actual or estimated amounts of energy consumed during the process of transmission of energy from generation resources or imports, at their points of injection into the grid, to demands at their points of withdrawal from the grid.

1. The methodologies that will be used for the calculation and application of the Transmission Loss Factors shall be developed by the ISO/RTO/transmission provider (or functional equivalent), in consultation with the Transmission Owners, and shall be filed with

the applicable regulatory authority for approval.

2. The methodologies that are used for the calculation and application of Transmission Loss Factors shall be posted on the ISO/RTO/transmission provider (or functional equivalent) website.

C. DISTRIBUTION LOSSES. Distribution losses are the actual or estimated amounts of energy consumed during the transmission of energy from the points at which energy is withdrawn from the transmission grid to the points of energy consumption.

1. The methodologies that will be used for the calculation and application of Distribution Loss Factors shall be developed by the ISO/RTO/transmission provider (or functional equivalent), in consultation with the Utilities, and shall be filed with the applicable regulatory authority for approval.

2. The methodologies that are used for the calculation and application of Distribution Loss Factors shall be posted on the ISO/RTO/transmission provider (or functional equivalent) website.

UNACCOUNTED-FOR-ENERGY

A. Unaccounted-for-energy (UFE) is the difference between generation (including imports) and exports plus load plus losses. Each scheduling coordinator shall be allocated a share of the total UFE pro rata with their load.

VIII. SUPPLIER TARIFF AND AGREEMENTS

A. SUPPLIER TARIFF. A standard uniform Supplier Tariff setting forth the rules governing the interactions between the Utility and the Supplier should be filed by all Utilities in the subject jurisdiction.

1. The Supplier Tariff sets forth the operational terms, and any fees associated therewith, to enable the Supplier to utilize the Utility's distribution system to serve customers;

2. The Supplier Tariff is not an executable document;

3. The Supplier Tariff does not make a Supplier eligible to service customers in the Utility's service territory;

4. Enforcement of any provision within the Supplier Tariff shall be under the jurisdiction of the applicable regulatory authority. Any proposed modifications by either the Utility or Suppliers must be submitted to the applicable regulatory authority for approval prior to implementation;

5. At a minimum, the following operational issues should be addressed in the Supplier Tariff, if applicable:

a. Any fees or charges;

b. Enrollment;

c. Imbalances;

d. Load Profiles;

e. Scheduling;

f. Billing;

g. Metering;

h. Retail Settlements;

i. Scheduling Coordinators;

j. Losses;

k. Customer Information;

l. Dispute Resolution Process;

m. Standard operating rules;

n. Performance Incentives and Standards; and

o. Creditworthiness.

B. SUPPLIER AGREEMENT. A standardized Supplier Agreement should be executed by the Utility and the Supplier. By executing the Agreement, the parties agree to operate under the terms of the Supplier Tariff.

1. The Supplier Agreement should set forth the legal obligations between the Utility and the Supplier. Nothing herein precludes the parties from negotiating additional or different provisions.

a. Since time is of the essence, any modifications to the standardized document shall be negotiated in good faith and in a timely fashion to permit the Supplier to commence serving customers within thirty (30) days of initial presentation of the Supplier Agreement. Should the parties fail to come to agreement, the parties shall default to language in the standardized Agreement.

2. At the discretion of the party seeking enforcement of the provisions of the Agreement, enforcement shall be by the applicable regulatory authority, arbitration, or through any court of competent jurisdiction.

3. The Supplier Agreement shall include the following provisions:

a. Representations and Warranties, including membership in Control Areas/Independent System Operators (or functional equivalent);

b. Indemnification;

c. Limitations on Liability;

d. Default (Breach) and Remedies;

e. Force Majeure;

f. Form/format of Scheduling Coordinators;

g. Miscellaneous, including Notice (including designation of agents and contractors), Assignment, Governing Law, and any modifications in writing; and

h. Commencement and Term.

C. TRADING PARTNER AGREEMENT. The Utility and the Supplier should execute a uniform Trading Partner Agreement, as required by the Standard Electronic Transmission (SET) protocols. See Exhibit 1 for a model Trading Partner Agreement to be executed by the parties.

STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT

THIS STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT (the Agreement) is made as of _____, ____, by and between _____, a _____ [specify corporation or other entity type], with offices at _____ and _____, a _____, [specify corporation or other entity type] with offices at _____ (collectively, the "parties").

RECITALS

WHEREAS, the parties desire to facilitate the exchange of reports, data and information required as set forth in the applicable regulatory authority orders, rules and regulations regarding the Standard Electronic Transactions and Business Practices standards, subject to the terms and conditions included in the Utility's applicable tariffs, by electronically transmitting and receiving data in agreed formats; and

WHEREAS, the parties desire that such electronic exchange fully comply with their underlying obligations as set forth in the applicable regulatory authority orders, rules and regulations regarding the Standard Electronic Transactions and Business Practice standards, subject to terms and conditions included in the Utility's applicable tariffs; and

WHEREAS, the parties desire to enter into this Agreement to govern their relationship with respect to computer to computer exchange of information, *i.e.*, Standard Electronic Transactions (SET).

NOW THEREFORE, in consideration of the premises and covenants herein contained, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties, intending to be legally bound, hereby agree as follows:

Section 1. Prerequisites

1.1 Data Communications. Each party shall electronically transmit to or receive from the other party any of the transaction sets listed in the Exhibit(s) (collectively Transactions), as such Exhibit(s) may be revised by written agreement. Any transmission of data which is not a Transaction, a Functional Acknowledgment, an electronic delivery mechanism error notification, or a time-stamp receipt response or record (collectively Data Communications) shall have no force or effect between the

parties. All Data Communications shall be transmitted in accordance with the standards and the published industry guidelines set forth in the Exhibit(s). The Exhibit(s) to this Agreement is(are) attached hereto. The Parties agree to conform to any subsequent modifications required by the SET Change and Control Group. Any other modifications of the provisions contained in this Agreement will be in writing and effective as set forth in the Exhibit(s).

1.2. Third Party Service Providers

1.2.1 Data Communications will be transmitted electronically between the parties as specified in the Exhibit(s), either directly or through any third party service provider (Provider) with whom either party may contract. Either party may modify its election to use, not use or change a Provider upon 30 days prior written notice to the other party.

1.2.2 Each party shall be responsible for the costs of any Provider with whom it contracts, unless otherwise set forth in the Exhibit(s).

1.2.3 Except for conditions described in Sections 4.6 and 4.7, each party shall be liable for any acts or omissions of its Provider while transmitting, receiving, storing, or handling Data Communications, or performing related transmission activities required to effectuate transactions pursuant to Section 2.

1.3 System Operations. Each party, at its own expense, shall provide and maintain the equipment, software, and services necessary to transmit and receive Data Communications. Each party also will be responsible for satisfying the applicable testing to demonstrate its ability to transmit and receive Data Communications.

1.4 Security Procedures

1.4.1 Each party shall use those security procedures specified in the Standard Electronic Transactions and Business Practices standards and/or the Exhibit(s).

1.4.2 For Internet transactions, the manner in which public encryption keys are to be changed and/or exchanged will be specified in the Exhibit(s).

1.4.3 Security Key Exchanges for Internet transactions. The parties shall maintain a public key used to facilitate secure electronic communication. The parties shall change their public key as set forth in the Exhibit(s). However, in emergency situations in which it is necessary to change a public or private key immediately, each party shall provide the other party with immediate notice of the change. Each party shall provide to the other its public key by either: (a) a certified or receipt mail service

using a diskette with the public key contained in an ASCII text file; (b) an electronic simple mail transfer protocol (SMTP) mail message with the public key contained in the body; or (c) through ANSI X.509 certificate management procedures. The public key shall be verified by the party to whom it is sent by validating the fingerprint of the public key by phone or by other comparable means.

1.5 Signatures for Internet transactions. Each party shall adopt as its signature private keys which shall be applied to each document transmitted by such party (Digital Signature). Each party agrees that the Digital Signature when decrypted by the receiving party shall be sufficient to authenticate the origin of the document. Neither party shall disclose to any unauthorized person the signature of the other party without the other party's prior consent.

Section 2. Transmissions

2.1 Proper Receipt

2.1.1 Transactions shall not be deemed to have been properly received, and no Transaction shall give rise to any obligation, until accessible to the receiving party at such party's Receipt Computer designated in the Exhibit(s), as evidenced by the receipt by sending party of the response initiated by receiving party. For Internet transactions, a HTTP response shall be used and shall specify the date and time of receipt of a Transaction at the receiving Internet server (also called time-c). No Transaction shall have any effect if the response is not received by sending party, or if the response indicates an error.

2.1.2 The Receipt Computer shall be defined in the Exhibit(s) as the receiving party's Uniform Resource Locator (URL), which describes the protocols which are needed to access the resources and point to the appropriate locations. Where the parties employ the services of Providers to transmit and receive Transactions, the Receipt Computer shall be defined in the Exhibit(s) as the receiving party's URL provided by the receiving party's Provider.

2.2 Digital Signature Verification and Decryption. Upon proper receipt of any Transaction, the receiving party shall attempt to decrypt the Transaction and verify the digital signature of the sending party. If the Transaction is verified and the decryption is successful, the receiving party shall transmit a Functional Acknowledgment in return. If the Transaction is verified and the decryption is unsuccessful, the receiving party shall send the applicable error message to the sending party. The sending party shall attempt to correct the error and promptly retransmit the Transaction or notify the receiving party in an attempt to solve the problem. If the decryption is successful, but the Transaction can not be verified, the receiving party shall transmit a Functional Acknowledgment

with an error message in return; however, if the receiving party can not ascertain the sending party's identity, then the transmission will not be deemed a Transaction.

2.3 Functional Acknowledgment Transaction

2.3.1 For the purposes of this Agreement, a "Functional Acknowledgment" means an ASC X12 Transaction Set 997 which confirms a Transaction has been received and whether all required portions of the Transaction are syntactically correct or not, but which does not confirm the substantive content(s) of the related Transaction. For the Transactions specified in Exhibit __ , a Functional Acknowledgment will be transmitted in the time period specified in the Exhibit(s).

2.3.2 If the Functional Acknowledgment indicates an error, neither party shall rely on the Transaction. The sending party shall attempt to correct the error and retransmit the Transaction or otherwise contact the receiving party in an attempt to resolve the problem. If the Functional Acknowledgment does not indicate any error, the Functional Acknowledgment shall constitute conclusive evidence a Transaction has been received in syntactically correct form.

2.3.3 If there has been proper receipt pursuant to Section 2.1, verification and successful decryption pursuant to Section 2.2, and if the receiving party nevertheless fails to transmit a Functional Acknowledgment, the sending party's records of the contents of the Transaction shall control, unless the sending party has retransmitted a Transaction pursuant to Section 2.3.4.

2.3.4 Retransmissions. For the Transactions specified in Exhibit __ , the sending party will retransmit a Transaction, in the time period specified in the Exhibit(s), if the sending party has not received a corresponding functional acknowledgment Transaction within the time frame indicated in the Exhibit(s). Such Transaction shall be considered a new transmission for purposes of Section 2.

Section 3. Terms

3.1 Transaction Terms and Conditions. This Agreement is intended to facilitate Data Communications between the parties conducted pursuant to underlying written agreements, including Exhibits and Service Agreements. In the event of conflict between this Agreement and the subject underlying written agreement(s), the terms and conditions of the underlying agreement(s) shall control.

3.2 Terms and Conditions of Reports and Other Information. This agreement is limited to providing reports and other information required by the applicable regulatory

authority orders and Working Group recommendations. Additional services and information will be subject to conditions referenced in the Exhibits, as shall be determined in accordance with applicable law.

3.3 Change in Terms and Conditions. Notwithstanding Section 4.1 of this Agreement, if any party determines that Data Communications under this Agreement are altered by a subsequent change to a party's tariff, the applicable laws or regulations, or obligation imposed by a governmental entity exercising jurisdiction over that party, then the affected party shall give immediate notice defining which Data Communications under this Agreement are affected, and the reasons therefore, and may provide notice of termination of this Agreement as provided in Section 4.8, as required by regulatory mandates, effective immediately upon receipt of such notice by the other party to this Agreement.

3.4. Confidentiality. Without express written consent from the customer, or by force of law, no party to this agreement will disclose such information to a person not party to this agreement. Any party to this agreement who discloses confidential information without express written consent or by force of law will indemnify the other party for any damages.

3.5. Validity: Enforceability

3.5.1 This Agreement has been signed and executed by the parties to evidence their mutual intent to be bound by the terms and conditions set forth herein relating to the electronic transmission and receipt of Data Communications.

3.5.2 Any Transaction properly transmitted pursuant to this Agreement shall be considered, in connection with any transaction, any other written agreement described in Section 3.1, or this Agreement, to be a "writing" or "in writing"; and any such Transaction when containing, or to which there is applied, a Digital Signature (Signed Transactions) shall be deemed for all purposes (a) to have been "signed" and (b) to constitute an "original" when printed from electronic files or records established and maintained in the normal course of business.

3.5.3 The parties agree not to contest the validity or enforceability of Signed Transactions under the provisions of any applicable law relating to whether certain agreements are to be in writing or signed by the party to be bound thereby. Signed Transactions, if introduced as evidence on paper in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the parties to the same extent and under the same conditions as other business records originated and maintained in Transactionary form. Neither party shall contest the admissibility of copies of Signed Transactions under either the business records exception to the hearsay rule or the best evidence rule on the basis that the Signed Transactions were not originated or maintained in Transactionary form.

Section 4. Miscellaneous

4.1 Term. This Agreement shall be effective as of the date first set forth above and shall remain in effect until terminated by either party with not less than 30 days prior written notice specifying the effective date of termination or in accordance with Section 3.3; provided, however, that written notice for purposes of this paragraph shall not include notice provided pursuant to an SET transaction; further provided, however, that any termination shall not affect the respective obligations or rights of the parties arising under any Transactions or otherwise under this Agreement prior to the effective date of termination.

4.2 Severability. Any provision of this Agreement which is determined by any court or regulatory body having jurisdiction over this Agreement to be invalid or unenforceable will be ineffective to the extent of such determination without invalidating the remaining provisions of this Agreement or affecting the validity or enforceability of such remaining provisions.

4.3 Entire Agreement. This Agreement and the Exhibit(s) constitute the complete agreement of the parties relating to the matters specified in this Agreement and supersede all prior representations or agreements, whether oral or written, with respect to such matters. No oral modification or waiver of any of the provisions of this agreement shall be binding on either party. No obligation to enter into any transaction is to be implied from the execution or delivery of this Agreement.

4.4 No Third Party Beneficiaries. This Agreement is solely for the benefit of, and shall be binding solely upon, the parties, their agents and their respective successors and permitted assigns. This Agreement is not intended to benefit and shall not be for the benefit of any party other than the parties hereto and no other party shall have any right, claim or action as a result of this Agreement.

4.5 Governing Law. This Agreement shall be governed by and interpreted in accordance with the laws of _____ [specify state, commonwealth, province, etc.] of _____, excluding any conflict-of-law rules and principles of that jurisdiction which would result in reference to the laws or law rules of another jurisdiction.

4.6 Force Majeure. No party shall be liable for any failure to perform its obligations in connection with any Transaction, where such failure results from any act of God or other cause beyond such party's reasonable control (including, without limitation, any mechanical, electronic or communications failure) which prevents such party from transmitting or receiving any Transactions and which such party is unable to prevent or

overcome after the exercise of due diligence in receiving and transmitting transactions under the terms of this Agreement.

4.7 Exclusion of Certain Damages. Neither party shall be liable to the other for any special, incidental, exemplary or consequential damages arising from or as a result of any delay, omission or error in the electronic transmission or receipt of any Data Communications pursuant to this Agreement, even if either party has been advised of the possibility of such damages and REGARDLESS OF FAULT. Any limitation on direct damages to software and hardware arising from Data Communications under this Agreement shall be set forth in the Exhibit(s).

4.8 Notices. All notices required or permitted to be given with respect to this Agreement shall be given by mailing the same postage prepaid, or given by fax or by courier, or by other methods specified in the Exhibit(s) to the addressee party at such party's address as set forth in the Exhibit(s). Either party may change its address for the purpose of notice hereunder by giving the other party no less than five days prior written notice of such new address in accordance with the preceding provisions.

4.9 Assignment. This Agreement may not be assigned or transferred by either party without the prior written approval of the other party, which approval shall not be unreasonably withheld; provided, any assignment or transfer, whether by merger or otherwise, to a party's affiliate or successor in interest shall be permitted without prior consent if such party assumes the responsibilities of this Agreement. Notice also must be provided to the other party.

4.10 Waivers. No forbearance by any party to require performance of any provisions of this Agreement shall constitute or be deemed a waiver of such provision or the right thereafter to enforce it.

4.11 Counterparts. This Agreement may be executed in any number of original counterparts all of which shall constitute one and the same instrument.

4.12 Reference Glossary. This section lists each defined term in this Agreement and cross references that term to its definition in the Agreement.

DEFINED TERM	WHERE DEFINED
Agreement	Header
Data Communications	Section 1.1
Digital Signature	Section 1.5
Transactions	Section 1.1
Standard Electronic Transaction, SET	Recital
Functional Acknowledgment	Section 2.3.1

parties	Header
Provider	Section 1.2.1
Receipt Computer	Section 2.1.2
Response Transaction	Section 2.3.4
Signed Transactions	Section 3.5.2
time-c	Section 2.1.1
Uniform Resource Locator, URL	Section 2.1.2

Each party has caused this Agreement to be properly executed on its behalf as of the date first above written.

Company Name: _____	Company Name: _____
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____

EXHIBIT ___
STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT
DATED _____
TO BE EFFECTIVE _____ (date)

1. Contact Information:

Company Name: _____
Street Address: _____
City: _____
State/Province/Commonwealth: _____
Zip/Postal Code: _____
Attention [Name, Title]:_____
Phone: _____Fax: _____Email Address: _____
Legal Entity Common Code (DUNS Number[1]): _____

Company Name: _____
Street Address: _____
City: _____
State/Province/Commonwealth: _____
Zip/Postal Code: _____
Attention [Name, Title]:_____
Phone: _____Fax: _____Email Address: _____
Legal Entity Common Code (DUNS Number): _____

2. Special Allocation Costs if Any: _____

[1] A registered trademark of Dun & Bradstreet Corporation.

EXHIBIT ___
STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT
DATED _____
TO BE EFFECTIVE _____ (date)

3. Communication Specifics:

Company Name: _____
SET Contact Phone Number: _____
Provider Name: _____
Receipt Company URL (include host name or IP address, any non standard port, Directory and program name as necessary): _____
Basic Authentication Userid: _____
Basic Authentication Password: _____
HTTP to/from Tag: _____
Is the transaction set supported in the HTTP envelope (Yes/No)? _____

Company Name: _____
SET Contact Phone Number: _____
Provider Name: _____
Receipt Company URL (include host name or IP address, any non standard port, directory and program name as necessary): _____
Basic Authentication Userid: _____
Basic Authentication Password: _____
HTTP to/from Tag: _____
Is the transaction set supported in the HTTP envelope (Yes/No)? _____

[Parties should execute a separate Exhibit for each different URL.]

EXHIBIT ___
STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT
DATED _____
TO BE EFFECTIVE _____ (date)

4. Transaction Sets:

Complete table for all applicable transaction sets (Refer to the applicable Home Page) for the current list of transaction set numbers and transaction names).

TRANSACTION SET NUMBER	TRANSACTION NAME	ISA Qualifier	SA ID	GS ID	ISA Qualifier	ISA ID	GS ID	Functional Acknowledgment	FA time frame

EXHIBIT ___
STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT
DATED _____
TO BE EFFECTIVE _____ (date)

5. Standards and Industry Guidelines: (Specify all applicable standards, issuing organizations, and published industry guidelines.)

_____
_____

Selected standards include, as applicable, all data dictionaries, segment dictionaries and transmission controls referenced in those standards for the transaction(s) contained in this Exhibit(s). The mutually agreed provisions of this Exhibit(s) shall control in the event of any conflict with any listed industry guidelines.

6. Security Procedures for Internet transactions: (Define security procedures, including but not limited to encryption, authentication, and PGP version.)

_____
_____

6.1 Public Encryption Key Exchange Procedures:

a) Contact for public encryption key exchange (emergency and scheduled)
_____

b) Method of contact and related information (phone number and/or e-mail address)
_____

c) Chosen electronic method of key exchange
_____

d) Scheduled public encryption key exchange procedures including frequency
_____

e) Emergency public encryption key exchange procedures
_____

f) Verification procedures to confirm appropriate exchange of public encryption keys
_____

g) Other _____

EXHIBIT ___
STANDARD ELECTRONIC TRANSACTIONS TRADING PARTNER AGREEMENT
DATED _____
TO BE EFFECTIVE _____ (date)

7. Terms and Conditions: (If no special terms and conditions have been agreed upon, enter None.)

_____
_____

8. Data Retention: (If no special data retention procedures have been agreed upon, enter None.)

_____
_____

9. Limitation on Direct Damages: (If no limitation has been agreed upon, enter None.)

_____
_____

10. Confidential Information: (See Section 3.4 If no limitation has been agreed upon, enter None.)

_____
_____

The undersigned do hereby execute this Exhibit pursuant to the Agreement attached and do hereby ratify said Agreement for all purposes set forth in this Exhibit.

Company Name:_____	Company Name:_____
By:_____	By:_____
Printed Name: _____	Printed Name: _____
Title:_____	Title:_____

IX. PERFORMANCE STANDARDS AND INCENTIVES

Non-compliance by any market participant with regulations promulgated by the applicable regulatory authority or with timetables and processes established by Working Group collaboratives results in additional costs and delays the implementation of effective retail access. In an effort to encourage compliance, performance standards, along with corresponding performance incentives, should be developed for all market participants, including Utilities, Suppliers, Meter Data Management Agents, Meter Reader Service Providers, and Meter Service Providers. Performance standards should be developed collaboratively within the state, with cost-based performance incentives designed to compensate the market participants who are in compliance and are relying on accurate and timely performance by other parties. Such cost-based structures for performance that is less optimal provide the appropriate signals to all market participants.

A. APPLICABILITY

1. Performance incentives should be imposed to recover the additional costs incurred by a party due to non-performance of the other party in providing timely and accurate information in conformance with standards and regulations imposed to effectuate retail access. Such incentives should be based on transactional costs and on the occurrence which best directly relates to the costs, such as per event or per month.

2. There should be two approaches for handling non-compliance:

a. Transactional performance incentives should be handled between the parties on a per transaction basis;

b. Systematic non-compliance should be addressed by the appropriate regulatory authority. Systematic non-compliance with the Supplier Tariff and enforcement of the Supplier Tariff provisions should be addressed as detailed in the Supplier Tariff and Agreements Document.

3. A 60-day grace period commencing on the first day data is exchanged between the parties, excluding test data, should be allowed when the market opens and for new market entrants.

4. A tolerance allowance for SET errors and rejections, such as 5 percent, should be allowed.

X. UTILITY-SUPPLIER DISPUTE RESOLUTION PROCESS

The following is a description of the dispute resolution process to govern disputes between Utilities and Suppliers regarding retail access interactions. The dispute resolution process between Suppliers and their customers should be governed by the applicable regulations and statutes. As described below, the dispute resolution process begins with an informal process between the parties, followed by a legal process, arbitration, or mediation before the applicable regulatory authority or court of competent jurisdiction if necessary.

A. RESOLUTION OF DISPUTES. The Utility and the Supplier shall use good faith and commercially reasonable efforts to informally resolve all disputes arising out of the implementation of the Supplier Tariff and/or the activities relating to retail access.

1. Any dispute between the Utility and the Supplier under the Supplier Tariff or relating to retail access shall be referred to a designated senior representative of each of the parties for resolution on an informal basis as promptly as practicable. The dispute must be established between the parties in writing and the notice shall include, at a minimum: a clear description of the dispute, the nature of the dispute, a contact name, and a proposed resolution.

2. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the parties may agree upon) such dispute, by mutual agreement, may be referred to mediation or may be submitted to binding arbitration and resolved in accordance with the current Commercial Arbitration Rules of the American Arbitration Association.

3. If the parties mutually agree to arbitration, the following procedures shall apply:

a. The parties shall request a five-member panel of arbitrators experienced in the subject matter of the dispute. Such panel shall be at least regional in makeup.

b. The parties shall alternatively strike proposed arbitrators until one remains who shall be the arbitrator. The parties may mutually reject an entire panel and request a new one.

c. The parties will equally incur the cost of arbitration prior to the decision being rendered by the arbitrator. The parties agree that the arbitrator will, in his or her decision, apportion responsibility for the costs associated with the arbitration, which may entail having one party reimburse the other for some or all costs already incurred.

B. RIGHTS UNDER FEDERAL LAW. Nothing in the Supplier Tariff shall restrict the rights of any party to pursue remedies through other forums, including administrative bodies and other forums recognized under federal law.

C. RIGHTS UNDER STATE LAW. Nothing in the Supplier Tariff shall restrict the rights of any party to file a complaint with the applicable regulatory authority under relevant provisions of the state statutes and regulations.

Appendix - Disclaimers

The proposed uniform business rules are the result of a collective, collaborative process and, as such, represent the views of the Coalition for Uniform Business Rules (CUBR) group as a whole. They do not necessarily represent the views of individual members of CUBR or affiliates of those members. Accordingly, these proposed business rules are not intended to be used against, or in connection with, any position taken or advocated by any individual member of CUBR or any affiliate of that member. Any individual member of CUBR, and any affiliate of that member, retains the right to challenge any of the proposed business rules or propose alternative business rules, if deemed appropriate.

The purpose of CUBR is to develop uniform business rules to be adopted by all states with competitive retail electric and/or natural gas markets. However, CUBR recognizes that notwithstanding these proposed business rules, the applicable existing and future laws and orders, policy statements, and regulations of the applicable federal and state regulatory authorities control.

CUBR's purpose is to develop uniform business rules that will serve to enhance competition and to encourage the appropriate regulatory authorities to adopt the same. The CUBR participants did not discuss topics or behavior that would result in anti-competitive behavior including, but not limited to: prices, markets, business tactics, or sales information. Nor did the CUBR participants discuss restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discriminations, division of markets, allocation of production, imposition of boycotts, or exclusive dealing arrangements.

COALITION FOR UNIFORM BUSINESS RULES
FACTS SHEET

The following facts sheet describes the efforts made to-date by the Coalition for Uniform Business Rules (CUBR) to develop a single set of business operating rules based on "best practices" for competitive retail electric and gas markets. Although CUBR's efforts only began in April 1999, CUBR released its comprehensive Uniform Business Rules recommendations in **September 1999**.

Top Ten Priority List

The top ten priority issues addressed by CUBR include: (i) Supplier licensing; (ii) customer information; (iii) enrollment and customer switching; (iv) creditworthiness; (v) billing and payments; (vi) electric metering; (vii) electric and natural gas operations; (viii) Supplier tariff and agreements; (ix) performance standards and incentives; and (x) Utility-Supplier dispute resolution process. In addition, CUBR currently is developing standard electronic transactions to implement the Uniform Business Rules, with data dictionaries and implementation guides to be released by the end of 1999.

Base Documents

In its effort to develop "best practices", CUBR based its recommended uniform business rules on currently existing business rules implemented in the states for electric and/or gas restructuring and by FERC for the wholesale industry. The models relied on for the base documents include GISB, UIG, California, Nevada, New York, Ohio, Pennsylvania, Massachusetts, and New Jersey. The base documents have been modified to reflect the collective experiences of the CUBR Members when implementing retail choice in the various states under different business rules.

Sponsoring Members

CUBR is comprised of Sponsoring Members, which are energy-related companies that have committed to participate in the development of the Uniform Business Rules and to share expenses, including the contract with the consultant hired to coordinate the drafting of the Uniform Business Rules.

The Sponsoring Members of the CUBR consists of a diverse cross section of the industry, representing gas and electric suppliers, utilities, meter data management agents, meter service providers, software providers, billing service providers, and entities that provide various mid and back-office support for suppliers. Currently, there are a total of 25 Sponsoring Members with

- 7 billing and/or meter service providers;
- 5 back office support and/or software vendors; and
- 13 retail electric suppliers, gas suppliers, and/or utilities, including

- 6 Utility-affiliated Suppliers and/or Utilities and
- 7 non-affiliated Suppliers.

Other Involved Participants

In addition to the Sponsoring Members, other entities have participated in CUBR's efforts, including State Commission Staff, consulting firms, different trade organizations, wholesale suppliers, and other competitive service providers and suppliers. There has been a strong push by the Members to include all interested parties in the discussions. For instance,

- EEI (Edison Electric Institute) attended a CUBR meeting, is actively monitoring the CUBR efforts, has a similar ongoing effort, and is in discussions with various CUBR members.

- NEMA (National Energy Marketers Association) has made a presentation at a CUBR meeting and has members actively participating.

- Center for the Advancement of Energy Markets made a presentation at a CUBR meeting.

- EPSA (Electric Power Supply Association) is actively monitoring the CUBR efforts and has members actively participating. EPSA is an Endorsing Organization of the CUBR Document and is actively involved in the outreach effort.

- GISB (Gas Industry Standards Board) is actively monitoring the CUBR efforts.

- UIG (Utility Industry Group) has made a presentation at a CUBR meeting, has agreed to work with CUBR on EDI implementation, and has Board members participating in CUBR efforts.

- At least 13 Commissions, including state Commissions and the Federal Trade Commission, are monitoring CUBR's progress through an electronic mail distribution list sent to interested Commissioners and/or Commission Staff.

- CUBR Members have made a presentation at the NARUC conference and are scheduled to speak at the GISB Annual Conference.

Time and Energy Commitment

From April through August 1999, CUBR met at least twice a month, with all-parties meetings held every two weeks either through 4-hour teleconferences or all day in-person work sessions, with the June, July and August meetings lasting at least 2 days.

Subgroups also met to develop recommendations on specific issues, including Metering, Electricity Operations, Gas Operations, Roll-Out Process, Standard Electronic Transactions, and Legal Issues. The subgroups met periodically either in person or *via* teleconferences to draft recommendations and best practices for the larger group to consider at the all-parties meetings. The Standard Electronic Transactions subgroup and the Roll-Out Process subgroup continue to meet to develop recommendations.

CUBR Timeline

The CUBR effort is a three-stage process designed for (i) planning, (ii) document development, and (iii) presentation. Each Stage is described below.

Stage 1

Begun in April 1999, the first stage was completed in late May 1999 with the formation of the group, the development of a top ten priority issue list, the commitment of companies, and the procuring of a consultant to coordinate the second stage.

- At least 3 in-person planning sessions and several teleconferences were held to organize CUBR and to begin the CUBR efforts.

- At least 76 individuals participated in stage 1, including Commission Staff, consultants, meter service providers, billing service providers, gas marketers, electric suppliers, software vendors, meter data management agents, wholesale energy suppliers, mid and back-office support providers, and other interested entities.

Stage 2

The second stage was a three-month effort to develop uniform business rules for retail access with a focus on the top ten priority issues discussed above. CUBR contracted with a consultant (the law firm John & Hengerer) to coordinate the efforts to complete a document on the ten priority issues in September.

- At each in-person meeting, an average of 25 individuals attended for an average of 7 hours per day. CUBR had 4 in-person meetings (a one day meeting in early June, followed by two 2-day meetings in late June and July and a 3-day meeting in late August (with over 30 people attending for over 22 hours)).

- Each teleconference was scheduled for at least 4 hours with at least 20 participants. CUBR has had 3 teleconferences with additional teleconferences scheduled through the end of the year.

- The man hours committed by the Sponsoring Members to stage 2 was consistently high with a minimum of 240 total man hours dedicated to all-parties

conference calls and a minimum of 1,535 total man hours dedicated to in-person work sessions, for a total of at least 1,775 man hours committed to all-parties meetings. In addition, the Sponsoring Members attended subgroup meetings and prepared comments and proposals before the meetings.

Stage 3

Stage 3 began in September 1999 with the release of the CUBR document outlining Uniform Business Practices. The document currently is being circulated and presented to interested parties and Commissions. For instance, CUBR representatives are scheduled to speak at the GISB Annual Meeting in September. In addition, the CUBR Members already have made a presentation to the Texas Commission and submitted a filing to the Virginia Commission on the CUBR efforts. The recommended Uniform Business Practices also are posted on the CUBR website, which is described in greater detail below.

Stage 3 also includes the development of uniform Standard Electronic Transaction (SET) data dictionaries, implementation guides, and information process flows for the CUBR business rules. The SET Subgroup began meeting in late August 1999. The uniform SET recommendations are expected by December 31, 1999.

Communications

In an effort to keep all interested parties informed and active in the CUBR discussions, CUBR is utilizing electronic communications to the greatest extent practical.

- There is an electronic distribution list for all Sponsoring Members and other interested entities to circulate meeting minutes, draft documents, comments, and concerns, as well as providing a forum for the Members to debate the implementation details.

- CUBR also circulates its meeting minutes and final documents to interested state and federal Commission Staff.

- CUBR has an Internet website to post the Uniform Business Rules, white papers, announcements of upcoming events, contact information, and other updates. The website's address is http://www.cubr.org.

The Sponsoring Members currently include:

- ABB,
- Altra Energy Technologies,
- Columbia Energy Services Corporation,
- Coral Energy,
- CSC Energy Services,
- DTE Edison America,
- Enron Corporation,
- Excelergy Corporation,
- Exelon Energy,
- Green Mountain.com,
- LG&E Retail Access Services,
- New Energy,
- Orcom Solutions, Inc.,
- PHASER Advanced Metering Services,
- PG&E Energy Services,
- PP&L EnergyPlus Company,
- Reliant Energy Retail, Inc.,
- Retx.com,
- SCT Corporation,
- Schlumberger,
- Shell Energy Services, L.L.C.,
- Strategic Energy Limited,
- TXU Electricity, and
- Utility.com.

The Endorsing Organizations include:

- Electric Power Supply Association (EPSA).