



California ISO
Shaping a Renewed Future

Business Practice Manual for Metering

Version ~~56~~

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Revision History

Version	Date	Description
Version 2	November 2, 2009	PRR 079 Metering BPM BPM update to reflect Payment Acceleration implementation
Version 3	August 10, 2010	BPM changes to further clarify Payment Acceleration language and incorporate Proxy Demand Resource implementation PRR 173 Metering BPM
Version 4	April 1, 2011	BPM changes to Section 12 Proxy Demand Resource. Includes registration process clarification including the ability to register "pseudo locations" and additional language to clarify PDR minimum load reduction requirements. BPM changes to Sections Changes revenue metering business practice for participating generators that are distribution connected resources (DCR), also referred to as distributed generation (DG). In particular, the changes modify the methodology used in determining the correction factor, attributed to losses and credits incurred to virtually meter at the CAISO Point of Receipt (POR), and how it is applied to CAISO metered entities revenue meters.
Version 5	June 30, 2011	BPM changes to Section 12 Proxy Demand Resource to include Reliability Demand Response Resource program – Tariff effective 4/1/12. Credit Reform (FERC 741) and Settlement Timeline Change Process (SPTC) Changes - various sections
<u>Version 6</u>	<u>March 7, 2012</u>	<u>PRR 543: Removal of RDRR from Metering BPM</u> <u>PRR 544: Revision to the Scheduling Coordinator Self-Audit Report</u> <u>BPM changes to Section 12 to remove the Reliability Demand</u>

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Version	Date	Description
		<u>Response Resource program. Changes to the guidelines provided for the SC Self Audit process.</u>

TABLE OF CONTENTS

1. Introduction	87
1.1 Purpose of California ISO Business Practice Manuals.....	87
1.2 Purpose of this Business Practice Manual.....	98
1.3 References.....	98
2. Overview of Metering CAISO	109
2.1 Metering Process.....	109
2.2 Installation & Certification of Meters.....	109
2.3 Overview of Flow of Meter Data.....	1140
2.4 Organization of BPM.....	1244
3. CAISO Responsibilities	1342
3.1 Overview of CAISO Responsibilities.....	1342
3.2 Meter Certification.....	1342
3.2.1 Overview of Meter Installation Certification Process.....	1443
3.2.2 CAISO Certification Responsibilities.....	1544
3.2.3 CAISO Metered Entities Certification Responsibilities.....	1544
3.2.4 Scheduling Coordinator Metered Entities Certification Responsibilities.....	2120
3.3 CAISO Authority to Require Additional Metering Facilities.....	2224
3.3.1 Requirement to Install.....	2224
3.3.2 Obligations of CAISO Metered Entity.....	2224
3.3.3 CAISO Metered Entity Election to Install Additional Metering.....	2322
3.4 Revenue Meter Data Acquisition & Processing System.....	2322
3.5 Communications Facilities Failure.....	2423
3.6 Audit & Testing.....	2423
3.7 Meter Data Retention.....	2423
4. Common CAISO Metered Entity & Scheduling Coordinator Metered Entity Responsibilities	2624
4.1 Netting.....	2624
4.1.1 Permitted.....	2624
4.1.2 Prohibited.....	2624
4.2 Accurate Meter Data.....	2725
4.3 Meter Data Intervals.....	2725
5. CAISO Metered Entity Responsibilities	2826

5.1	Revenue Quality Meter Data.....	2826
5.1.1	Format & Collection of Meter Data	2926
5.1.2	Access to Settlement Quality Meter Data	2927
5.1.3	Maintenance & Repairs	3027
5.1.4	Meter Site Security.....	3128
5.2	Certification of Metering Facilities	3129
5.3	Telecommunication Requirements.....	3129
6.	Scheduling Coordinators for SC Metered Entity Responsibilities.....	3330
6.1	Provision of Settlement Quality Meter Data SQMD	3330
6.1.1	SQMD Submission Format & Timing.....	3434
6.1.2	Access to SQMD Systems	3835
6.1.3	Process for Submittal & Resubmittal of SQMD.....	3835
6.1.4	Failure to Submit Accurate SQMD (Actual, Estimated).....	3935
6.2	Certification of Meters	3936
6.3	Audit & Testing	3936
6.3.1	Scheduling Coordinator Self-Audit Report	3936
6.3.2	Audit & Testing by CAISO	4238
7.	Meter Service Agreements	4339
7.1	CAISO Metered Entities.....	4339
7.2	Scheduling Coordinator Metered Entities.....	4339
7.3	Scheduling Coordinator Agreement	4440
7.4	Qualifying Facility Participating Generator Agreement.....	4440
8.	Exemptions.....	4544
8.1	Guidelines.....	4544
8.1.1	Publication of Guidelines.....	4544
8.1.2	Metering Exemption Publication	4642
8.2	Request for Exemption Procedure	4642
8.3	Permitted Exemptions.....	4743
8.3.1	Exemptions from Providing Meter Data Directly to RMDAPS	4743
8.3.2	Exemptions from Meter Standards	4743
9.	Other Metering Configurations	4844
9.1	Metered Subsystems	4844
9.2	Dynamic System Resource Meters.....	4945

9.3	Metering for Separate UFE Calculations	<u>4945</u>
9.4	Metering for Participating Load Program.....	<u>4945</u>
10.	Station Power Program.....	<u>5046</u>
10.1	Station Power Program Overview	<u>5046</u>
10.2	Eligibility.....	<u>5147</u>
10.3	Limitations	<u>5147</u>
10.4	Applications to Self-Supply Station Power	<u>5147</u>
10.5	CAISO Monitoring & Review	<u>5248</u>
10.6	Self-Supply Verification & CAISO Charges	<u>5349</u>
10.7	Station Power Portfolio Set-Up	<u>5450</u>
10.8	Provision of Data to UDC or MSS Operator	<u>5551</u>
11.	Qualifying Facility (QF) Metering	<u>5652</u>
11.1	Inapplicability of Requirements to Regulatory Must-Take Generation	<u>5652</u>
11.2	QF Eligibility for Net Metering	<u>5652</u>
11.2.1	Demonstration of QF Status	<u>5652</u>
11.2.2	Demonstration of Standby Service or Curtailment of Self-Provided Load ..	<u>5753</u>
11.2.3	Execution of a QF PGA.....	<u>5753</u>
11.3	Permitted Netting for Net Scheduled QFs	<u>5753</u>
12.	Proxy Demand Response (PDR) and Reliability Demand Response Resource (RDRR) Programs.....	<u>12-5812-54</u>
12.1	Program Overview	<u>12-5812-54</u>
12.2	Process Overview.....	<u>12-6112-56</u>
12.3	Executing a Demand Response Provider Agreement	<u>12-6212-57</u>
12.4	Demand Response System.....	<u>12-6512-60</u>
12.5	Resource Registration	<u>12-6612-64</u>
12.6	Using the Demand Response System for Meter Data Submission, Customer Baseline, and Demand Response Energy Measurements	<u>12-8012-72</u>
12.7	PDR No Pay Dispatch Performance (meter before/after in 5 minute intervals)	<u>12-9612-90</u>
12.8	Direct Load Control Demand Response Energy Measurement.....	<u>12-9712-94</u>
12.9	DRS Monitoring Process.....	<u>12-9712-92</u>
12.10	Outages.....	<u>12-9712-92</u>

Attachment A: End Use Meter Standards.....1

Attachment B: Technical Specifications1

Attachment C: CAISO Authorized Inspector Initial Site Verification and Meter Test procedures1

Attachment D: CAISO Data Validation, Estimation and Editing Procedures for Revenue Quality Meter Data (RQMD)1

Attachment E: CAISO Audit of Certified Metering Facilities1

Attachment F: Station Power Reallocation Example.....1

Attachment G: Proxy Demand Resource (PDR) ~~and Reliability Demand Response Resource (RDRR)~~ Baseline Calculation Example.....3

List of Exhibits:

Exhibit 1-1: CAISO BPMs87

Exhibit 2-1: Overview of Installation and Certification of Meters1140

Exhibit 2-2: Overview of Meter Data Flow to obtain SQMD1244

Exhibit 3-1: Meter Installation Certification Process.....1443

Exhibit 6-1: Overview of Settlement Quality Meter Data Submittal Deadline.3734

~~Exhibit 6-2: Scheduling Coordinator Self Audit Timeline35~~

1. Introduction

Welcome to CAISO ***BPM for Metering***. In this Introduction you will find the following information:

- The purpose of CAISO BPMs
- What you can expect from this CAISO BPM
- Other CAISO BPMs or documents that provide related or additional information

1.1 Purpose of California ISO Business Practice Manuals

The Business Practice Manuals (BPMs) developed by CAISO are intended to contain implementation detail, consistent with and supported by the CAISO Tariff, including: instructions, rules, procedures, examples, and guidelines for the administration, operation, planning, and accounting requirements of CAISO and the markets. Exhibit 1-1 lists CAISO BPMs.

Exhibit 1-1: CAISO BPMs

Title
BPM for Market Operations
BPM for Market Instruments
BPM for Settlements & Billing
BPM for Scheduling Coordinator Certification and Termination
BPM for Congestion Revenue Rights
BPM for Candidate CRR Holder Registration
BPM for Managing Full Network Model
BPM for Rules of Conduct Administration
BPM for Outage Management
BPM for Metering
BPM for Reliability Requirements
BPM for Credit Management
BPM for Compliance Monitoring
BPM for Definitions & Acronyms
BPM for BPM Change Management
BPM for the Transmission Planning Process

1.2 Purpose of this Business Practice Manual

The *BPM for Metering* covers the metering responsibilities for the CAISO, CAISO Metered Entities, Scheduling Coordinator (SC) Metered Entities, and Scheduling Coordinators representing Metered Entities for the meter installation, certification and maintenance in addition to the creation of Settlement Quality Meter Data (SQMD).

The provisions of this BPM are intended to be consistent with the CAISO Tariff. If the provisions of this BPM nevertheless conflict with the CAISO Tariff, the CAISO is bound to operate in accordance with the CAISO Tariff. Any provision of the CAISO Tariff that may have been summarized or repeated in this BPM is only to aid understanding. Even though every effort will be made by CAISO to update the information contained in this BPM and to notify Market Participants of changes, it is the responsibility of each Market Participant to ensure that he or she is using the most recent version of this BPM and to comply with all applicable provisions of the CAISO Tariff.

A reference in this BPM to the CAISO Tariff, a given agreement, any other BPM or instrument, is intended to refer to the CAISO Tariff, that agreement, BPM or instrument as modified, amended, supplemented or restated.

The captions and headings in this BPM are intended solely to facilitate reference and not to have any bearing on the meaning of any of the terms and conditions.

1.3 References

Other reference information related to this BPM includes:

- *The BPM for Rules of Conduct Administration*
- *The BPM for Full Network Model*
- *The BPM for Settlements and Billing*

2. Overview of Metering CAISO

Welcome to the *Overview of Metering* section of the *BPM for Metering*. In this section you will find the following information:

- A description of the metering process
- A diagram of the meter installation and certification process
- A diagram of the flow of Meter Data

2.1 Metering Process

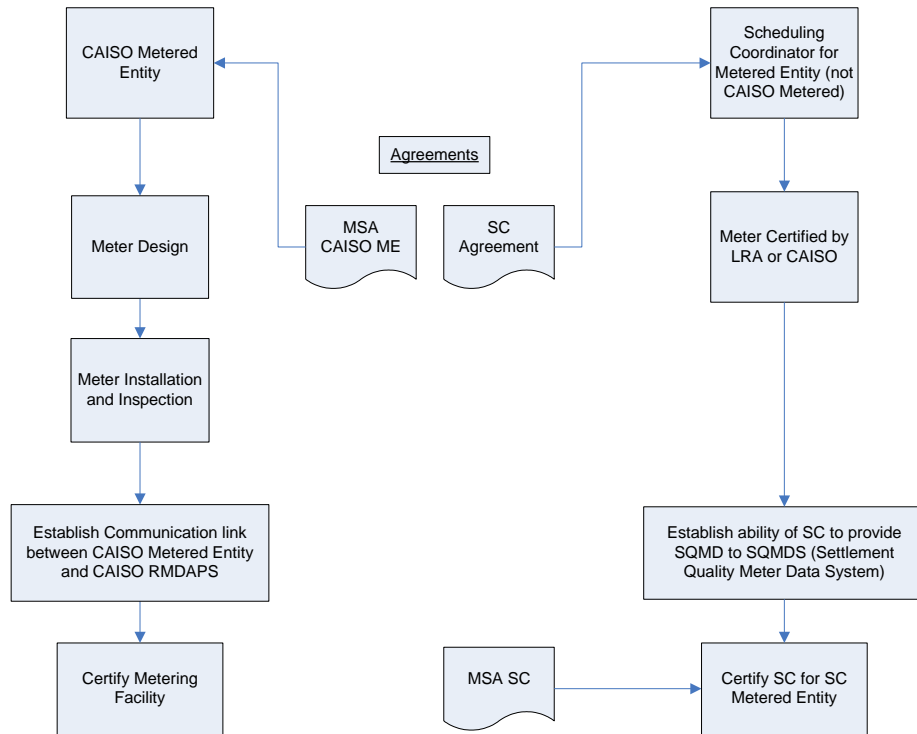
This BPM describes the process and procedures used by the CAISO, CAISO Metered Entities, and Scheduling Coordinators for Scheduling Coordinator Metered Entities to obtain SQMD used for the Settlement of the CAISO Markets. SQMD is used for billable quantities to represent the Energy generated or consumed during a Settlement Interval. SQMD is obtained from two different sources: CAISO Metered Entities (Meter Data directly polled by CAISO) and Scheduling Coordinator Metered Entities (Meter Data submitted to CAISO by Scheduling Coordinators). This BPM provides information regarding:

- CAISO installation requirements of Metering Facilities
- How the CAISO certifies Metering Facilities for CAISO Metered Entities and meters for Scheduling Coordinator Metered Entities
- Necessary agreements for participation in the CAISO Markets
- How Meter Data is created and submitted by CAISO Metered Entities and Scheduling Coordinators for Scheduling Coordinator Metered Entities
- CAISO's role in creating SQMD through Validation, Editing and Estimation (VEE)
- Audit, testing, and maintenance requirements of Metering Facilities

2.2 Installation & Certification of Meters

Exhibit 2-1 illustrates the process for installation and certification of Metering Facilities for CAISO Metered Entities and meters for Scheduling Coordinator Metered Entities.

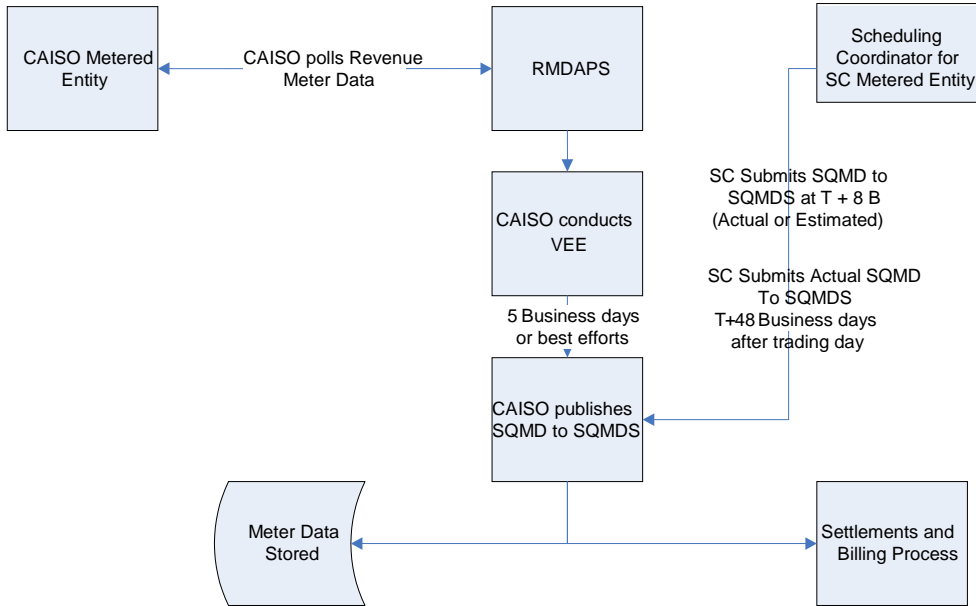
Exhibit 2-1: Overview of Installation and Certification of Meters



2.3 Overview of Flow of Meter Data

Exhibit 2-2 illustrates the relationship between CAISO, CAISO Metered Entities, and Scheduling Coordinator Metered Entities to obtain SQMD.

Exhibit 2-2: Overview of Meter Data Flow to obtain SQMD



2.4 Organization of BPM

The following Sections 3, 4, 5, and 6 describe the respective responsibilities of CAISO, CAISO Metered Entities and Scheduling Coordinators for Scheduling Coordinator Metered Entities. Sections 7 through 12 describe provisions for Meter Service Agreements, exemptions, other metering configurations, Station Power metering, and metering for Qualifying Facilities and Proxy Demand Resources.

3. CAISO Responsibilities

Welcome to the *CAISO Responsibilities* section of the *BPM for Metering*. In this section you will find the following information:

- An overview of CAISO responsibilities
- A description of the installation and certification process for Metering Facilities
- A description of the Revenue Meter Data Acquisition and Processing System (RMDAPS) system
- A description of the procedure followed in the event of communication facility failures
- A description of the auditing and testing requirements
- A description of Meter Data retention policy of CAISO

3.1 Overview of CAISO Responsibilities

CAISO Tariff Section 10.1.1

The CAISO is responsible for establishing and maintaining the Revenue Meter Data Acquisition and Processing System (RMDAPS) and the Settlement Quality Meter Data System (SQMDS). RMDAPS acquires Revenue Quality Meter Data which is processed into SQMD (actual) for use in the CAISO's Settlement and billing process and SQMDS acquires Scheduling Coordinators' Settlement Quality Meter Data (actual, estimated). The CAISO is also responsible for the following for CAISO Metered Entities:

- (a) setting standards and procedures for the registration, certification, auditing, testing, and maintenance of revenue quality meters and
- (b) establishing procedures for the collection, security, validation and estimation of Meter Data

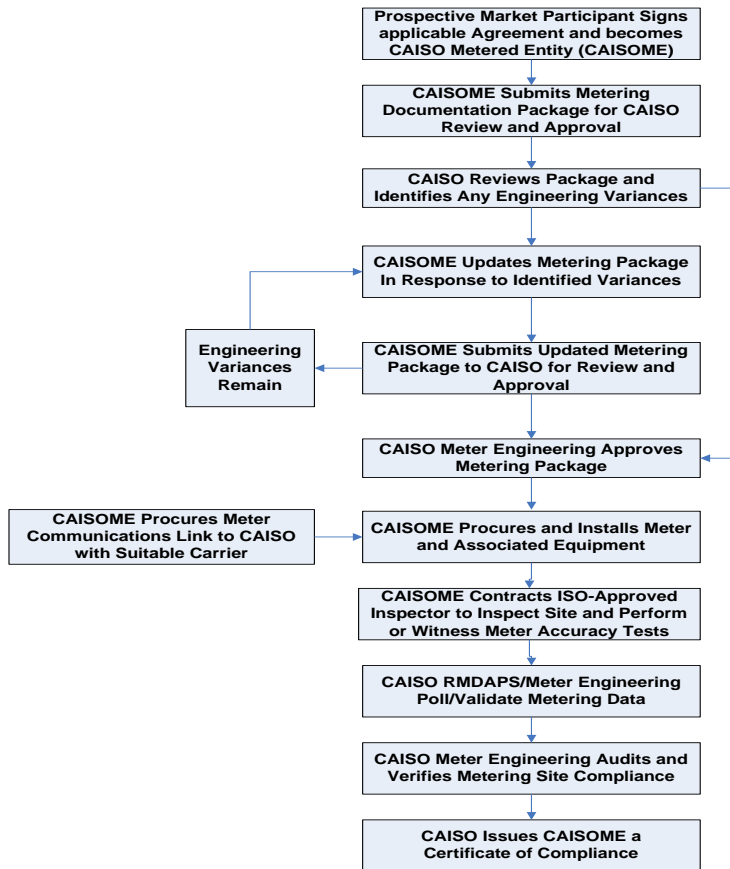
3.2 Meter Certification

CAISO has overall responsibility for certification. Some of this responsibility is accomplished by the responsibilities placed on CAISO Metered Entities and Scheduling Coordinators for Scheduling Coordinator Metered Entities. This Section 3.2 summarizes the respective certification responsibilities of CAISO, CAISO Metered Entities and Scheduling Coordinators with respect to Scheduling Coordinator Metered Entities.

3.2.1 Overview of Meter Installation Certification Process

Exhibit 3-1 provides a high level illustration of the overall certification process for Metering Facilities.

Exhibit 3-1: Meter Installation Certification Process



3.2.2 CAISO Certification Responsibilities

CAISO does not accept Meter Data from a CAISO Metered Entity unless that Meter Data is produced by Metering Facilities that are certified in accordance with the CAISO Tariff and this BPM and has a current Certificate of Compliance or a provisional Certificate of Compliance¹.

CAISO does not accept SQMD relating to a Scheduling Coordinator Metered Entity unless it is produced by Metering Facilities that are certified in accordance with:

- The certification or similar criteria prescribed by the relevant Local Regulatory Authority (LRA)²
- If the Local Regulatory Authority has not prescribed any certification criteria for the Metering Facilities, the certification criteria prescribed for CAISO Metered Entities by this BPM apply.

As indicated below in Section 3.2.3, for the purpose of these certification requirements, references to CAISO Metered Entities include the Scheduling Coordinators for the Scheduling Coordinator Metered Entities where the certification requirements are not covered by the certification requirements of a Local Regulatory Authority.

3.2.3 CAISO Metered Entities Certification Responsibilities

CAISO Metered Entities must use a certified meter, request and provide information for a certified Metering Facility and have a CAISO Authorized Inspector review and inspect the facility. CAISO has the final authority to settle accuracy disputes between the CAISO Authorized Inspector and the Metering Facility.

3.2.3.1 End Use Meter Standards

All metering is of a revenue class metering accuracy in accordance with the ANSI C12 standards on metering and any other requirements of the relevant UDC or Local Regulatory Authority that apply. Such requirements apply to meters, current transformers and potential transformers, and associated wiring and equipment. End Use Meter Standards are located in Attachment A of this BPM.

¹ A provisional Certificate of Compliance may be issued if the CAISO finds that (a) the data provided to it by the CAISO Metered Entity or the Scheduling Coordinator for the Scheduling Coordinator Metered Entity is incomplete or fails to meet the relevant standards referred to in the CAISO tariff and this BPM or (b) the Metering Facilities fail the RMDAPS interface test

² CAISO may require Scheduling Coordinators to provide it with a copy of any certificate issued by the Local Regulatory Authority in respect of the Metering Facilities of each SC Metered Entity they represent. The Scheduling Coordinator must provide to CAISO a copy of such certificate within five business days of receiving the request for the certificate from CAISO.

3.2.3.2 Certification Criteria

The criteria for certifying the Metering Facilities of CAISO Metered Entities include meeting the requirements for installation, certification and establishment of communication equipment. All requests made to CAISO to perform the certification of Metering Facilities must be made in accordance with the Technical Specifications (Attachment B). If CAISO agrees to perform the certification of Metering Facilities, CAISO and the CAISO Metered Entity must agree to the terms and conditions on which the CAISO undertakes the certification including the assistance provided by the CAISO Metered Entity, the responsibility for costs and the indemnities provided.

3.2.3.3 Inspection by CAISO Authorized Inspectors

A CAISO Metered Entity seeking certification of its Metering Facilities independently engages a CAISO Authorized Inspector to perform inspection of its Metering Facilities and requests the CAISO to perform the certification of its Metering Facilities. It is the responsibility of the relevant CAISO Metered Entity to ensure that any inspector it engages to undertake the inspection of its Metering Facilities holds a current certificate of approval issued by the CAISO, which authorizes that inspector to carry out the duties of a CAISO Authorized Inspector.

The CAISO publishes on the CAISO Website, for informational purposes only, a list of the CAISO approved meter inspection companies at:

<http://www.caiso.com/docs/2005/10/01/2005100119040822976.html>

If a CAISO Metered Entity would like the CAISO to perform the inspection of its Metering Facilities, the CAISO Metered Entity must submit a letter to the CAISO Manager of Operations Support. The request letter must contain the following:

- Specify the Metering Facilities to be certified
- Provide the documentation referred to in Section 3.2.3.4 of this BPM
- Detail the reasons why the CAISO Metered Entity cannot engage the services of a CAISO Authorized Inspector to perform the inspection. An acceptable request must include either, 1) information about the requesting entity's contacts with no less than two CAISO Authorized Inspectors and an explanation of why the requesting entity could not contract with the CAISO Authorized Inspector or 2) a compelling explanation why it was impossible or impractical for the requesting entity to make such contacts with two CAISO Authorized Inspectors. [Note: Any such request could be available to the public under the CAISO Information Availability Policy.]

The CAISO, within 14 days of receiving a request for it to inspect Metering Facilities, informs the CAISO Metered Entity whether it undertakes the inspection or requires the CAISO Metered Entity to engage a CAISO Authorized Inspector to perform the inspection. The site name of approved locations will be posted on the CAISO Website.

3.2.3.4 Documentation Requirements

To initiate the Certification process, the CAISO Metered Entity must provide the following information to the CAISO and to the CAISO Authorized Inspector:

- Schematics – The CAISO Metered Entity provides schematics (both detailed and one line) of the metering installation being considered for CAISO certification. Such drawings must be dated, bear the current drawing revision number and show all wiring, connections and devices in the circuits. Drawings must be provided for
 - Instrument transformers to meter
 - Meter to public carrier telecom circuit
 - Meter to CAISO Point of Receipt (POR), where the CAISO POR differs from the meter location
- The CAISO Metering Certification Form and corresponding Site Verification Data Sheet located on CAISO Website at:

<http://www.caiso.com/docs/2005/10/01/2005100119040822976.html>
- Transformer and Line Loss Worksheets
- Distribution Compensation Factor (DCF) engineering study (if applicable per BPM section 5.1.1) with letter of agreement of DCF from appropriate UDC/Distribution Company/ Interconnection entity.
- Additional Documentation
 - Map to the site and/or GPS coordinates
 - Contact personnel
 - System Description Overview: An overview should include a brief description one page or less of the operation of the site. Examples would be the meter used and how it communicates with the CAISO. The size of the Generating Unit and

associated Load should also be included. Other examples include the Point of Delivery of Energy to the CAISO Controlled Grid and all relevant information about current transformers and voltage transformers that include line and transformer loss compensation. The operation of the meters input and output circuits.

- Communication information: Provide the IP Address and Port Assignment

3.2.3.5 Meter Facility Site Acceptance, Verification, & Meter Test

The CAISO Authorized Inspector must complete a CAISO approved Site Verification Data Sheet in relation to each set of Metering Facilities that it inspects. The Site Verification Data Sheet is posted on the CAISO Website at:

<http://www.caiso.com/docs/2004/08/25/200408251522071790.pdf> (4 channel)

<http://www.caiso.com/docs/2004/08/25/200408251525202079.pdf> (6 channel)

The CAISO Authorized Inspector provides the most recent test results documenting instrument calibration results by serial number and the traceable link to the National Institute for Science and Technology (NIST).

Details of the CAISO Authorized Inspector site acceptance criteria include verification of:

- Drawings and documentation
- Meter and related component locations
- Name plate data of instrument transformers
- Name plate of Generating Unit, if applicable
- Revenue meter calibration limits
- Meter and related components, seals, and locks
- Applied instrument transformer burdens
- Applied metering constants
- Communications
- Metering compensation (including transformer losses, line losses and distribution compensation factor, *when applicable*)

The CAISO Authorized Inspector also conducts a site verification and either performs or witnesses the performance of accuracy tests for the Metering Facility installations. Details of these verification steps can be found in Attachment C.

3.2.3.6 CAISO Review of Documentation

If there are any discrepancies between the CAISO certified drawings on file and the actual metering circuitry inspected by the CAISO Authorized Inspector or CAISO, then the CAISO requests that the owner or authorized owner representative document that discrepancy and revise the schematic drawings provided to CAISO. Where the CAISO Authorized Inspector discovers a discrepancy, they must notify CAISO and the CAISO Metered Entity of the discrepancy within 24 hours of the discovery.

CAISO reviews all documentation provided to it by the CAISO Metered Entity and the site verification form prepared by the CAISO Authorized Inspector. If CAISO finds the data is incomplete or fails to meet the relevant standards referred to in the CAISO Tariff and this BPM, The CAISO provides written notice of the deficiencies to the CAISO Metered Entity within seven days of receiving the documentation referred to above.

3.2.3.7 Certification Testing & Issuance of Certificate of Compliance

CAISO may unconditionally approve, conditionally approve or reject a proposal for installation.

- **Unconditional Approval** – If the CAISO unconditionally approves a proposal for installation, it will notify the CAISO Metered Entity that the proposal for installation has been approved. The CAISO Metered Entity then begins installation of the Metering Facilities in accordance with the proposal for installation.
- **Conditional Approval** – If the CAISO conditionally approves a proposal for installation, it will notify the CAISO Metered Entity that the proposal for installation has been conditionally approved and set out in that notice the conditions on which approval is granted at the time period in which each condition must be satisfied by the CAISO Metered Entity.

If the CAISO Metered Entity disputes any condition imposed by the CAISO, the CAISO Metered Entity must notify CAISO of its concerns and provide CAISO with the reasons for its concerns. If the CAISO Metered Entity gives the CAISO such a notice, the CAISO may amend or waive any of the conditions on which it granted its approval or it may require the CAISO Metered Entity to satisfy other conditions. The CAISO and the CAISO Metered Entity will use reasonable good faith efforts to reach agreement, and in the absence of agreement either entity may refer the dispute to an alternative dispute resolution process.

The CAISO Metered Entity must notify the CAISO when each condition in the approval has been satisfied and provide to the CAISO any information reasonably requested by

the CAISO as evidence that such condition has been satisfied. The CAISO determines that a condition in the approval of the proposal for installation is satisfied, it provides the CAISO Metered Entity written confirmation that the condition is satisfied. If the CAISO determines that a condition is not satisfied, the CAISO notifies the CAISO Metered Entity that it does not consider the condition satisfied. If, after using all reasonable good faith efforts, the CAISO and the CAISO Metered Entity are unable to agree on whether that condition is satisfied, either entity may refer the dispute to an alternative dispute resolution process.

- **Rejection** – If the CAISO rejects a proposal for installation, it notifies the CAISO Metered Entity that the proposal is rejected. The CAISO Metered Entity must submit CAISO a revised proposal for installation within 14 Business Days of receiving the notice of rejection. If the CAISO rejects for a second time a proposal for installation submitted by a CAISO Metered Entity in respect to the same or similar notice issued by CAISO, the CAISO and CAISO Metered Entity use all reasonable good faith efforts to reach agreement on the requirements and disputed items and in the absence of agreement either party may refer the dispute to an alternative dispute resolution process.

If CAISO finds that the certification process described above is complete, it initiates tests to certify the RMDAPS interface with the relevant Metering Facilities (See Attachment C, Section C4, Communications Circuit Test).

Upon successful completion of the RMDAPS interface test, CAISO issues a Certificate of Compliance or provisional Certificate of Compliance.

3.2.3.8 Metering Facility Maintenance

CAISO Metered Entities must ensure proper operation and integrity of the metering equipment. The CAISO recommends CAISO Metered Entities test their Metering Facilities a minimum of once every two years. To ensure that this standard is maintained, a site audit process by the CAISO occurs periodically. The site audit is a review by CAISO of the Metering Facility data as recorded as part of the Metering Facility certification and as documented in the most current Site Verification Data Sheet on file at CAISO.

3.2.3.9 Revocation of Certificate of Compliance

CAISO may revoke in full or in part any Certificate of Compliance or provisional Certificate of Compliance if:

- It has reasonable grounds to believe that all or some of the Metering Facilities covered by that Certificate of Compliance no longer meet the certification criteria for Metering Facilities contained in the CAISO Tariff and this BPM.
- It has given written notice to the relevant CAISO Metered Entity stating that it does not believe that the identified Metering Facilities meet the certification criteria (including the reasons for that belief) and that the CAISO Metered Entity fails to satisfy the CAISO, within the time period specified in the CAISO's notice, that the Metering Facilities meet the certification criteria.

If the CAISO revokes in full or part a Certificate of Compliance, the relevant CAISO Metered Entity may request recertification.

3.2.3.10 Modification of Metering Facilities

CAISO approval must be obtained before any modifications or changes are made to any Metering Facilities of a CAISO Metered Entity that have been certified pursuant to the CAISO Tariff or this BPM. The CAISO may, at its discretion, require those Metering Facilities to be recertified.

3.2.4 Scheduling Coordinator Metered Entities Certification Responsibilities

Scheduling Coordinators for Scheduling Coordinator Metered Entities must ensure the metered entities they represent have certified meters or must follow the certification process for CAISO Metered Entities.

3.2.4.1 Local Regulatory Agency Certification Requirements

Scheduling Coordinators representing Scheduling Coordinator Metered Entities must ensure the meters for their Scheduling Coordinator Metered Entities are certified in accordance with the certification requirements of the appropriate Local Regulatory Authority (LRA). Scheduling Coordinators are responsible for obtaining any necessary approval of the relevant Local Regulatory Authority to its proposed security and VEE procedures. The CAISO does not perform any VEE procedures on the actual or estimated Settlement Quality Meter Data it receives from Scheduling Coordinators for Scheduling Coordinator Metered Entities.

3.2.4.2 No Local Regulatory Agency Certification Requirements

If the relevant Local Regulatory Authority has not prescribed any certification criteria for the Metering Facilities of a Scheduling Coordinator Metered Entity, the Scheduling Coordinator representing that Scheduling Coordinator Metered Entity must promptly notify the CAISO in

writing that no such criteria have been prescribed. That Scheduling Coordinator is then responsible for ensuring that the Scheduling Coordinator Metered Entities it represents obtain and maintain Certificates of Compliance in respect of all of the Metering Facilities of those Scheduling Coordinator Metered Entities in accordance with this BPM. Scheduling Coordinators must engage a CAISO Authorized Inspector to perform the certification of any Metering Facilities that are certified under this BPM and otherwise follow the requirements of Section 3.2.3 for CAISO Metered Entities.

3.3 CAISO Authority to Require Additional Metering Facilities

CAISO Tariff Section 10.2.14

CAISO has the authority under the CAISO Tariff to require a CAISO Metered Entity to install Metering Facilities. In directing the addition of meters and metering system components that would impose increased costs on a CAISO Metered Entity, CAISO will give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs. A CAISO Metered Entity may not start installation of additional metering until CAISO has approved its proposal for Installation.

3.3.1 Requirement to Install

If CAISO determines that there is a need to install additional Metering Facilities on the CAISO Controlled Grid, it notifies the relevant CAISO Metered Entity of that need. The CAISO's notice to that CAISO Metered Entity will include:

- Location of the meter point at which the additional Metering Facilities are required
- Date by which the CAISO Metered Entity must install the relevant Metering Facility
- The reason for the need to install the additional Metering Facilities
- Any other information the CAISO considers relevant

3.3.2 Obligations of CAISO Metered Entity

A CAISO Metered Entity that is notified by CAISO that it is required to install additional Metering Facilities must:

- Give CAISO written confirmation of receipt of that notice within three Business Days of receiving that notice
- Submit a proposal for installation to CAISO within 45 Business Days of receiving that notice. The proposal for installation must set out the following information:

- ❖ A description of the proposed Metering Facilities to be installed (which includes all relevant schematic drawings and one–line drawings)
- ❖ A proposed timetable for the installation
- ❖ Any other information requested by CAISO

3.3.3 CAISO Metered Entity Election to Install Additional Metering

A CAISO Metered Entity may choose to install additional metering, including Backup Meters. If a CAISO Metered Entity installs such additional metering, such metering must, unless the CAISO agrees otherwise:

- Be installed and maintained at CAISO Metered Entity's cost
- Be located on CAISO Metered Entity's side of any primary meter
- Not interfere with the accuracy of any primary meter and, if that primary meter is directly polled by CAISO, the CAISO's ability to directly poll that meter

Any meter data produced by additional metering may be used by CAISO for Settlement and billing purposes in the event of the failure, or during tests or repairs of, the primary meter provided that the following conditions are all satisfied: (i) such additional metering has a current Certificate of Compliance; (ii) the CAISO Metered Entity gives CAISO prior verbal notice that such meter is used and the period for which it will be used; and (iii) if the primary meter is directly polled by CAISO, that additional metering is capable of being directly polled by CAISO.

3.4 Revenue Meter Data Acquisition & Processing System

CAISO uses RMDAPS to read the CAISO Metered Entities' meters on a daily basis. CAISO also retrieves data from the meters that provides information on the health of the meter (i.e., error logs, back up battery status, etc.). CAISO is responsible for taking the raw unedited Meter Data and performing the Validation, Estimation, and Editing (VEE) procedures to produce actual Settlement Quality Meter Data. CAISO VEE procedures are contained in Attachment D.

In addition, VEE is conducted on individual meter reads that are aggregated with other meters to produce the specific resource ID SQMD. This includes Generating Unit resource IDs that are made up of multiple Generating Units electrically connected at the same point or Generating Units that are considered a Physical Scheduling Plant (e.g., hydro units associated with a contiguous water flow that are dependent upon each other for operations).

CAISO makes its best effort to read the CAISO Metered Entities' meters and make the SQMD available to the CAISO Metered Entities (and their Scheduling Coordinators) within five Business Days. The Scheduling Coordinator or the CAISO Metered Entity can obtain their Meter Data, by resource ID, from the SQMDS. The CAISO Metered Entities can verify and monitor their data to assure the data is as expected.

Note that RMDAPS does not collect Meter Data for Scheduling Coordinator Metered Entities. The Scheduling Coordinators for Scheduling Coordinator Metered Entities submit actual or estimated Settlement Quality Meter Data directly into SQMDS.

3.5 ~~Communications Facilities Failure~~ Failure of CAISO Facilities or Systems

CAISO Tariff Section 10.1.6

In the event facility and/or system failure impacts the CAISO's ability to accept, collect, and process Revenue Quality Meter Data or Settlement Quality Meter Data, alternative measures may be required by the CAISO, CAISO Metered Entities, and Scheduling Coordinator Metered Entities.

These measures are communicated to the market via CAISO Market Notice.

3.6 Audit & Testing

CAISO Tariff Section 10.2.11

Certified CAISO Metered Entities are subject to CAISO Metering Facility audits, and testing. CAISO has the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the CAISO Metered Entity. Details of the Metering Facility audits are outlined in Attachment E.

The audit and testing requirements for Scheduling Coordinator Metered Entities, including the self-audit requirements, are described in Section 6.3.

3.7 Meter Data Retention

CAISO Tariff Section 10.1.2

The CAISO maintains a record of all Revenue Quality Meter Data and Settlement Quality Meter Data provided to it, as well as the Settlement Quality Meter Data it produces, for a period of 18 months on-site at CAISO's facilities and for a period which, at least, allows for the re-run of data

as required by the CAISO Tariff and any adjustment rules of the Local Regulatory Authority governing the Scheduling Coordinators and their End-Use Customers and FERC. The CAISO, on reasonable notice, provides a Scheduling Coordinator with access to Settlement Quality Meter Data (actual or Scheduling Coordinator estimated) provided that the Scheduling Coordinator requesting access represented the entity for which that data was provided at the time the data was provided to the CAISO.

4. Common CAISO Metered Entity & Scheduling Coordinator Metered Entity Responsibilities

Welcome to the *Common CAISO Metered Entity and Scheduling Coordinator Metered Entity Responsibilities* section of the *BPM for Metering*. In this section you will find the following information that applies to both CAISO Metered Entities and Scheduling Coordinator Metered Entities:

- A description of permitted and prohibited netting of Generating Unit output and the Demand of auxiliary Load equipment
- A description of requirement to provide accurate Meter Data
- A description of the interval over which Meter Data is recorded

4.1 Netting

This section describes the permitted and prohibited netting opportunities for CAISO Metered Entities and Scheduling Coordinators for Scheduling Coordinator Metered Entities. Netting opportunities for Station Power and for Qualifying Facilities are described in Sections 10 and 11, respectively, of this BPM for Metering.

4.1.1 Permitted

CAISO Tariff Section 10.1.3.1

CAISO Metered Entities and Scheduling Coordinators may, when providing Meter Data to CAISO, net MWh values for Generating Unit output and auxiliary Load equipment electrically connected to that Generating Unit at the same point provided that the Generating Unit is on-line and is producing sufficient output to serve all of that auxiliary Load equipment.

For example, where a Generating Unit's auxiliary Load equipment is served via a distribution line that is separate from the switchyard to which the Generating Unit is connected, that Generating Unit and auxiliary Load equipment is not considered to be electrically connected at the same point.

4.1.2 Prohibited

CAISO Tariff Section 10.1.3.2

CAISO Metered Entities or Scheduling Coordinators must not net values for Generating Unit output and Load. CAISO Metered Entities or Scheduling Coordinators that serve third party

Load connected to a Generating Unit's auxiliary system must add that third party Load to the Generating Unit's output. The CAISO Metered Entity must add that third party Load to the Generating Unit's output either by means of a hard wire local meter connection between the metering systems of the third party Load and the Generating Unit or by requesting CAISO to use RMDAPS to perform the addition. Scheduling Coordinators representing Scheduling Coordinator Metered Entities that serve third party Load connected to the auxiliary system of a Generating Unit must ensure that those Scheduling Coordinator Metered Entities add the Energy consumed by such third parties to that Generating Unit's output so as to ensure proper settlement of that Generating Unit's gross output. The CAISO Metered Entity or the Scheduling Coordinator must ensure that the third party Load has Metering Facilities that meet the standards referred to in this BPM.

4.2 Accurate Meter Data

CAISO Tariff Section 37.5.2

CAISO Metered Entities and Scheduling Coordinators for Scheduling Coordinator Metered Entities must provide CAISO with complete and accurate Meter Data, subject to penalties and Sanctions specified in CAISO Tariff Section 37.11. Pursuant to Section 37.11, CAISO has the authority to impose Sanctions as outlined in that provision and in the BPM for Rules of Conduct Administration under the Inaccurate Meter Data section. In addition, Section 4.1 of both the *pro forma* Meter Service Agreement for Scheduling Coordinators and the *pro forma* Meter Service Agreement for CAISO Metered Entities provides the authority for CAISO to impose penalties and Sanctions, including but not limited to suspension of trading rights, if a Scheduling Coordinator or CAISO Metered Entity provides inaccurate, incorrect or fraudulent Meter Data to CAISO. Such penalties and Sanctions must be approved by FERC. Additional information related to penalties and Sanctions, including suspension of trading rights can be found in the Meter Service Agreement and *BPM for Rules of Conduct Administration*, as applicable.

4.3 Meter Data Intervals

CAISO Tariff Section 10.2.9.2

Subject to any exemption granted by CAISO, CAISO Metered Entities and Scheduling Coordinators for Scheduling Metered Entities must record Meter Data in Standard Time as follows:

- At five minute intervals for Loads and Generating Units providing Ancillary Services and/or Imbalance Energy
- At one hour intervals for other Meter Data

5. CAISO Metered Entity Responsibilities

Welcome to the *CAISO Metered Entities Responsibilities* section of the *BPM for Metering*. In this section you will find the following information:

- A description of Revenue Quality Meter Data
- A description of the installation, maintenance and repair of meters
- An indication of where to find meter certification requirements
- A description of the communications requirements
- A description of CAISO imposed penalties and Sanctions
- A description of the provisions for third party access to Meter Data

CAISO Tariff Section 10.2

CAISO Metered Entities provide Revenue Quality Meter Data directly to CAISO via the revenue quality meters that are directly polled by CAISO's RMDAPS. As indicated in Sections 3.2.2 and 3.2.4.2, this Section 5 also applies to Scheduling Coordinator Metered Entities for which there are no Local Regulatory Authority certification requirements.

5.1 Revenue Quality Meter Data

CAISO Tariff Section 10.2.1.1

CAISO Metered Entities must ensure that Revenue Quality Meter Data from their meters directly connected to the CAISO Controlled Grid or at interconnections, including interconnections between utility Service Areas which have separate UFE calculations, is made available to CAISO RMDAPS in accordance with the requirements of Section 10 of the CAISO Tariff and this Business Practice Manual.

The measurement from CAISO Metered Entities revenue meters must be represented at the point of receipt (POR) to the ISO Controlled Grid.

5.1.1 Revenue Metering at the Point of Receipt (POR)

Where a CAISO Metered Entity is connected in a radial manner to the ISO Controlled Grid, applicable radial line and transformer losses must be programmed into the revenue meter to reflect the point of receipt at the CAISO Controlled Grid. Loss factors for such radial lines and

transformers shall be determined in accordance with Attachment B, Technical Specifications, of this BPM

Where a CAISO Metered Entity is connected to a Utility Distribution Company's (UDC) Distribution System, applicable radial line and transformer losses, as well as Distribution System losses or credits, referred to as a Distribution Compensation Factor, must be programmed into the meter to reflect the point of delivery at the CAISO Controlled Grid. Loss factors for such radial lines and transformers shall be determined in accordance with Attachment B, Technical Specifications, of this BPM.

The Distribution Compensation Factor, accounting for losses or credits attributed across a Distribution System, must be based on an engineering study and not be in conflict with any interconnection or Tariff agreements entered into between the CAISO Metered Entities and the UDC/Distribution Provider to which they are connected. In the absence of an engineering study, the CAISO will accept a default Distribution Compensation Factor of 1.0. All Distribution Compensation Factors must be reviewed by and agreed upon by the CAISO, CAISO Metered Entity and the UDC/Distribution Provider.

The CAISO will recognize an engineering study found in a distribution Interconnection Service Agreement or Access Tariff filing as a valid, independent study for purposes of determining the Distribution Compensation Factor.

Agreement of the Distribution Compensation Factor by all parties will be a pre-condition to CAISO meter certification. The agreed upon compensation factor and applicable radial line and transformer losses shall be programmed into the ISO revenue meter.

5.1.2 Format & Collection of Meter Data

CAISO Metered Entities must ensure that the Meter Data obtained by the CAISO directly from their revenue quality meters is raw, unedited and un-aggregated Meter Data in kWh values. The CAISO will be responsible for the Validation, Estimation and Editing process of that Meter Data in order to produce Settlement Quality Meter Data.

Meter Data is presently collected on a daily basis. CAISO may also collect Meter Data on demand. CAISO issues such demands using voice communications. If CAISO issues a demand for Meter Data to a CAISO Metered Entity, the CAISO Metered Entity must provide that Meter Data to CAISO within 10 minutes of receiving the demand from CAISO or, if that CAISO Metered Entity has been granted an exemption from directly interfacing with RMDAPS, within the time period specified in that exemption.

5.1.3 Access to Settlement Quality Meter Data

CAISO Tariff Section 10.2.1.3

CAISO Metered Entities and Scheduling Coordinators representing CAISO Metered Entities obtain Settlement Quality Meter Data by directly accessing the Settlement Quality Meter Data System (currently OMAR On-line for web access or OMAR through FTP process).

Meter Data from CAISO polled meters is validated, estimated and edited to produce Actual Settlement Quality Meter Data that is made available to Scheduling Coordinators by T+5B to be used in the Recalculation Settlement Statement T+12B, which the CAISO calculates at T+8B. In the event Revenue Quality Meter Data is not available by T+8B, the CAISO will estimate outstanding metered Demand and/or Generation for Settlement Quality Meter Data for CAISO Metered Entities in accordance with CAISO Tariff Sections 10.3.6.1 and 11.1.5.

If the CAISO is notified in accordance with CAISO Tariff Section 10.2.13.2 that the revenue quality meter for a CAISO Metered Entity requires repair, the CAISO will produce Settlement Quality Meter Data (actual) for that entity using the estimation procedures referred to in CAISO Tariff Section 10.2.9, which will be made available to the Scheduling Coordinator for the CAISO Metered Entity within forty-eight (48) business days from the Trading Day (T+48B) and will be used in the Recalculation Settlement Statement T+55B calculation.

5.1.4 Maintenance & Repairs

CAISO Tariff Section 10.2.13.1

CAISO Metered Entities must maintain their Metering Facilities so that those Metering Facilities continue to meet the standards prescribed by the CAISO Tariff and this BPM.

If the Metering Facilities of a CAISO Metered Entity require maintenance in order to ensure that they operate in accordance with the requirements of the CAISO Tariff, the CAISO Metered Entity must notify CAISO by telephone or other means specified by CAISO of the need for such maintenance. The CAISO Metered Entity must also inform CAISO of the time period during which such maintenance is expected to occur. During that period, the CAISO Metered Entity or its authorized representative is entitled to access those sealed Metering Facilities to which access is required in order to undertake the required maintenance. Maintenance should be documented in the CAISO Maintenance Form. This form is located on the Site Verification Data Sheet at: www.aiso.com.

During periods for which no Meter Data is available from a meter that has a current Certificate of Compliance, CAISO substitutes Meter Data for that CAISO Metered Entity using the VEE process as stated in Section 3.4. That Meter Data is used by CAISO in its Settlement and billing process.

CAISO Tariff Section 10.2.13.2

If a certified meter of a CAISO Metered Entity requires repairs to ensure that it operates in accordance with the requirements of this BPM, the CAISO Metered Entity, or its SC, must immediately notify CAISO of the need for repairing that meter and must ensure that those repairs are completed:

- Where there is no Backup Meter installed, repairs need to be completed within 48 hours of the notification by CAISO
- Where there is a Backup Meter installed, repairs need to be completed within five Business Days of the notification to the CAISO

During periods for which no Revenue Quality Meter Data is available from a meter that has a Certificate of Compliance, the CAISO will create and provide access to the Settlement Quality Meter Data for use in the Settlement Statement calculations.

5.1.5 Meter Site Security

CAISO Tariff Section 10.2.8.1

CAISO Metered Entities (including communications devices) and secondary devices that could have any impact on the performance of the Metering Facilities must be sealed by CAISO or CAISO Authorized Inspector.

The NEMA³ enclosures containing the CAISO certified meter³ must be located in a secure location. In addition, revenue meters and revenue meter test switches must be sealed. The (test switches) shorting switches for the current circuit and the voltage switches (if one exists) must be sealed to prevent loss of revenue. Instrument transformer secondary compartments must be secured with a CAISO seal.

5.2 Certification of Metering Facilities

Section 3.2.3 describes the specific requirements for certification and the maintenance of Metering Facility certification for CAISO Metered Entities.

5.3 Telecommunication Requirements

CAISO Metered Entities must provide the proper telecommunication channels and router/terminal servers to CAISO's secure communication system. The CAISO Metered Entity

³ National Electrical Manufacturers Association

must provide telecommunications between (both to and from) CAISO's secure communication network to its revenue quality meters that are in accordance with the CAISO Information Security Requirements⁴. CAISO Metered Entities must provide router/terminal servers to interface the telecommunication channels to revenue quality meters. Each revenue quality meter uses an RS-232 interface or other CAISO approved technology.

⁴ CAISO Information Security Requirements are located on the CAISO Website at, <http://www.caiso.com/177d/177d93982c5c0.html>.

6. Scheduling Coordinators for Scheduling Coordinator Metered Entity Responsibilities

Welcome to the Scheduling Coordinators *for Scheduling Coordinator Metered Entities Responsibilities* section of the *BPM for Metering*. In this section you will find the following information:

- A description of Settlement Quality Meter Data
- An indication of where to find meter certification requirements
- A description of a possible requirement to obtain consents from UDCs, other utility Distribution System operators and/or TOs to which its Scheduling Coordinator Metered Entities are connected
- A description of the auditing and testing provisions for Scheduling Coordinator Metered Entities

Scheduling Coordinators that represent metered entities (Load and Generating Units) that are not directly polled by CAISO are responsible for submitting SQMD to CAISO. The Scheduling Coordinator must submit Estimated or Actual Settlement Quality Meter Data relating to the Scheduling Coordinator Metered Entities they represent to the CAISO by the given Meter Data submission deadlines referenced in the CAISO Payments Calendar. A detailed CAISO Payments Calendar may be found on the CAISO Website.

6.1 Provision of Settlement Quality Meter Data

CAISO Tariff Section 10.3.2.1

A Scheduling Coordinator shall be responsible for:

- The collection of Meter Data for the Scheduling Coordinator Meter Entities it represents.
- The submission of Actual or Estimated Settlement Quality Meter Data to the CAISO and meeting the Meter Data submittal deadlines as outlined in the CAISO Payments Calendar.
- Ensuring sound estimation practices and other available information is used when submitting estimated data by T+8B, including but not limited to bids, schedules, forecasts, operating logs, and historical data. Estimated data must be

a good faith estimate that reasonably represents Demand and/or Generation quantities for each Settlement Period.

- Replacing Estimated Settlement Quality Meter Data used in the Recalculation Settlement Statement T+55B no later than T+48B.
- Ensuring Settlement Quality Meter Data submitted to the CAISO meets the requirements of CAISO Tariff Section 10.
- Aggregating Settlement Quality Meter Data to the level of the registration configuration of a Proxy Demand Resource specified in the Demand Response System.

6.1.1 Settlement Quality Meter Data Submission Format & Timing

CAISO Tariff Section 10.3.2.2

Settlement Quality Meter Data is submitted to the Settlement Quality Meter Data Systems in PST format year round.

Scheduling Coordinators shall submit Settlement Quality Meter Data (Actual or Estimated) to the Settlement Quality Meter Data System for the Scheduling Coordinator Metered Entities they represent using one of CAISO's approved Meter Data Exchange Formats.

Each Scheduling Coordinator must submit Settlement Quality Meter Data in either kWh or MWh values, whichever is applicable, for all of the Scheduling Coordinator Metered Entities that it schedules aggregated by:

- Load Aggregation Points (LAPs) and PNode
- The relevant PNode for Generating Units

Meter Data Exchange Format (MDEF) and Comma Separated Values (CSV) format specifications can be found in the OMAR MDEF CSV Specification 4.1 document available on the CAISO Website at:

<http://www.caiso.com/docs/2005/10/28/200510281045562024.html>

Timing of Settlement Quality Meter Data

Initial Settlement Statement T+3B (CAISO Tariff Section 10.3.6.1)

The ISO will estimate all meter data for the T+3B statement which includes:

- Scheduling Coordinator Metered Entities
- CAISO Meter Entities
- Non-PTO wheeling data
- Proxy Demand ~~Resources and Reliability Demand Response Resources~~

Recalculation Settlement Statement T+12B (CAISO Tariff Section 10.3.6.2)

Scheduling Coordinators can submit either Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO no later than 23:59:59 (Pacific Time) on the eighth Business Day after the Trading Day (T+8B) for the Recalculation Settlement Statement T+12B calculation.

- Estimated Settlement Quality Meter Data will not be accepted by the CAISO after the T+8B Meter Data submittal deadline.
- When Actual or Estimated Settlement Quality Meter Data is not received for a Scheduling Coordinator Metered Entity by T+8B, 23:59:59 Pacific Time, the CAISO will estimate metered Generation and/or Demand for the Recalculation Settlement Statement T+12B, including Proxy Demand ~~Resources and Reliability Demand Response Resources~~.

Recalculation Settlement Statement T+55B (CAISO Tariff Section 10.3.6.23)

Scheduling Coordinators must submit Actual Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO no later than 23:59:59 on the forty-eighth business day after the Trading Day (T+48B) for the Recalculation Settlement Statement T+55B to avoid possible Sanctions pursuant to CAISO Tariff Section 37.5.

- Actual Settlement Quality Meter Data not received by the CAISO by the Meter Data submittal deadline of T+48B is considered late and subject to Sanctions pursuant to the Rules of Conduct set forth in Section 37.5 of the CAISO Tariff.
- Scheduling Coordinator Estimated Settlement Quality Meter Data must be replaced no later than T+48B. Estimated Settlement Quality Meter Data not replaced by actual data

will be considered late and the Scheduling Coordinator will be subject to Sanctions pursuant to Section 37.5 of the CAISO Tariff.

- Any CAISO Estimated Settlement Quality Meter Data not replaced with Actual Settlement Quality Meter Data by the Scheduling Coordinator by T+48B will be set to zero and will not be used for any subsequent Recalculation Settlement Statements.

Submission of meter data after the T+48B meter submittal deadline (CAISO Tariff Section 10.3.6.34)

Scheduling Coordinators may continue to submit Actual Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO for use in Recalculation Settlement Statements according to the timelines established in the CAISO Payments Calendar.

- A re-submittal window used in the calculation of the T+9M statement will be open for a period of five business days at T+168B to T+172B.
- Meter Data submitted outside of the 5 business day window (T+168B – T+172B) will be automatically rejected and not used in settlements. Once rejected, data must be resubmitted according to the timeline.
- Meter Data submitted after the T+48B deadline will be subject to Rules of Conduct and interest based on the recalculated settlement amount.
- Penalties associated with the Rules of Conduct will be based on a given Trade Date per Scheduling Coordinator ID (SCID) regardless of the number of versions submitted within the window
- To avoid additional penalties associated with the re-submittal of meter data, the corresponding Trade Date (TD) must adhere to the PST format.

For example:

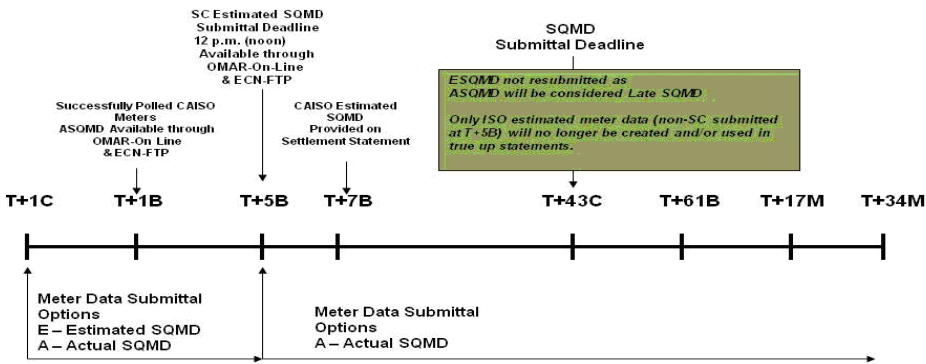
DST Trade Date: TD1 = TD -1 HE 23:00 – TD1 23:00

PST Trade Date: TD1 = TD1 HE 1:00 – HE 24:00

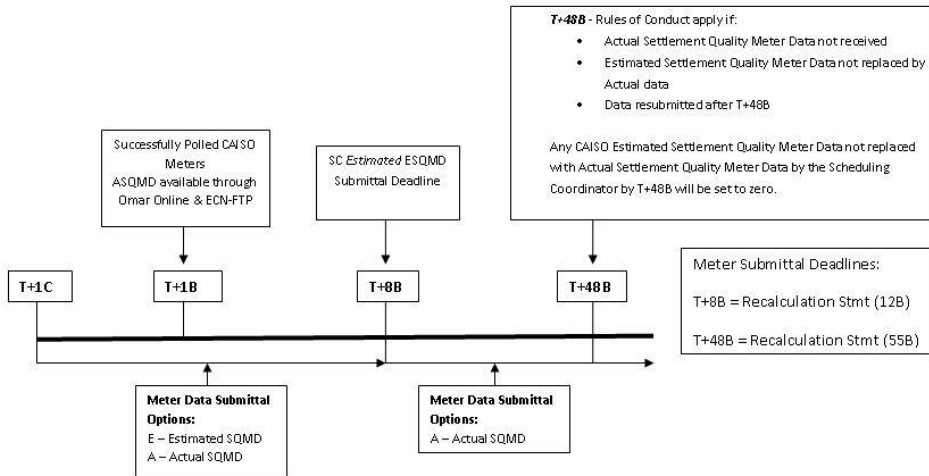
Otherwise,

Data submitted for a DST Trade Date composed of HE 1:00 – HE 24:00 PST will shift to TD1 HE 2:00 – TD2 HE 1:00 reflecting 2 Trade Dates.

Exhibit 6-1: Overview of Settlement Quality Meter Data Submittal Deadline.
Process prior to Trade Date October 1, 2011



Process effective Trade Date October 1, 2011



6.1.1.1 Loss Factors

CAISO Tariff Section 10.3.3

Where a Scheduling Coordinator Metered Entity is connected to a UDC's Distribution System, the responsible Scheduling Coordinator shall adjust the Meter Data by an estimated Distribution System loss factor to derive an equivalent CAISO Controlled Grid level measure. Such estimated Distribution System loss factors shall be approved by the relevant Local Regulatory Authority prior to their use. The Scheduling Coordinator must aggregate its equivalent CAISO Controlled Grid-level Meter Data for its Scheduling Coordinator Metered Entities.

6.1.1.2 Approved Load Profile Authorization

CAISO Tariff Section 10.3.4

Scheduling Coordinators are responsible for obtaining all necessary authorizations from Local Regulatory Authorities having jurisdiction over the use of profiled Meter Data in any Settlement process in which Approved Load Profiles are used to allocate consumption to Settlement Periods.

6.1.2 Access to Settlement Quality Meter Data Systems

Scheduling Coordinators can obtain access to the Settlement Quality Meter Data Systems (currently OMAR On-line for web access or OMAR through FTP process). Access to OMAR On-line can be obtained by requesting a secured digital certificate. Digital certificate request forms are located on the CAISO Website at:

<http://www.caiso.com/pubinfo/info-security/certs/index.html>

Access to OMAR through the FTP process can be obtained by completing the Settlement Quality Meter Data Systems Certification requirements detailed on the CAISO Website at:

<http://www.caiso.com/1ba8/1ba884ee185a0.pdf>

6.1.3 Process for Submittal & Re-submittal of Settlement Quality Meter Data

All SCs for Scheduling Coordinator Metered Entities are responsible for submitting SQMD in Standard Time either hourly time-stamped SQMD for Scheduling Coordinator Metered Entities or profiled cumulative SQMD to CAISO for each Settlement Period except for the Initial

Settlement Statement T+3B (CAISO Estimated). SQMD is considered complete when the SC's file contains appropriate Meter Data for all of the Scheduling Coordinator Metered Entities that the SC represents on that Trading Day.

Scheduling Coordinators must also submit SQMD on demand. CAISO issues such demands using voice communications. If CAISO issues a demand for SQMD, the SC from which CAISO demands that data must submit it to CAISO within four hours of receiving the demand from CAISO.

6.1.4 Failure to Submit Accurate Settlement Quality Meter Data (Actual, Estimated)

Actual Settlement Quality Meter Data not successfully received by the CAISO for a Scheduling Coordinator Metered Entity by T+48 business days from the Trading Day is considered late Meter Data. Any occurrence of late Meter Data is a violation of the CAISO Tariff and may receive Sanctions as described in Section 37.5.2 and Section 37.6.1 of the CAISO Tariff.

Refer to Section 6.1.1 of this BPM and CAISO Tariff Section 10.3.6 regarding actual and estimated Settlement Quality Meter Data and the consequence of not submitting accurate and actual Settlement Quality Meter Data.

6.2 Certification of Meters

Section 3.2.4 describes the Scheduling Coordinator Metered Entities specific requirements for meter certification and the Scheduling Coordinator for the Scheduling Coordinator Metered Entity responsibility to ensure maintenance of that certification as required by the Local Regulatory Authority or UDC.

6.3 Audit & Testing

Scheduling Coordinators representing Scheduling Coordinator Metered Entities are required to perform an annual Scheduling Coordinator Self-Audit report and may also be audited or tested by CAISO.

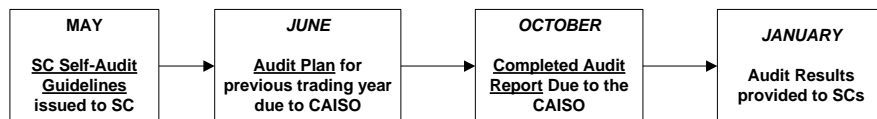
6.3.1 Scheduling Coordinator Self-Audit Report

CAISO Tariff Section 10.3.10

Each Scheduling Coordinator for Scheduling Coordinator Metered Entities shall at least annually conduct (or engage an independent, qualified entity to conduct) audits and tests of the Metering Facilities of the Scheduling Coordinator Metered Entities that it represents and the Meter Data

provided to the Scheduling Coordinator in order to ensure compliance with all applicable requirements of any relevant Local Regulatory Authority. Scheduling Coordinators shall undertake any other actions that are reasonably necessary to ensure the accuracy and integrity of the Settlement Quality Meter Data (actual or Scheduling Coordinator estimated) provided by them to the CAISO. The SC Self-Audit must evaluate the process flow of Meter Data beginning with the Validation, Estimation and Editing (VEE) and following the process through submittal of Actual SQMD to the CAISO. ~~The general audit timeline is shown in Exhibit 6-2:~~

~~Exhibit 6-2: Scheduling Coordinator Self-Audit Timeline~~



~~CAISO sends Scheduling Coordinator Self-Audit guidelines to Scheduling Coordinators in May of the applicable audit year. Specific guidelines are identified for the following entities.~~

- ~~➤ Guidelines for small entities (one meter in portfolio and \leq 150 MWh/day)~~
- ~~➤ Guidelines for cities~~
- ~~➤ Guidelines for others~~

~~Audit Review Period for the present year will be from August 1st of previous year through July 31st of the current year and the report is due to the ISO on October 31st of the present year. If the due date is not a business day, then the report is due on the first business day in November. Failure to submit an audit report by the due date is a violation of tariff requirement 10.3.10.1 and results in a Rules of Conduct violation, section 37.6.3.2, of \$1,000/day until the report is received by the ISO.~~

~~Scheduling Coordinators have 30 days from the date of receipt of the Scheduling Coordinator Self-Audit guidelines to provide a Scheduling Coordinator Self-Audit plan to CAISO. The Scheduling Coordinator Self-Audit plan must state how the Scheduling Coordinator intends to perform the Scheduling Coordinator Self-Audit. The Scheduling Coordinator Self-Audit plan must include the following:~~

- ~~➤ A discussion of the activities and interfaces the Scheduling Coordinator represents~~
- ~~➤ A description of its process used to acquire and submit Estimated Settlement Quality Meter Data to the CAISO~~

- ~~A timeline of activities the Scheduling Coordinator represents, such as, but not limited to, what:

 - ~~Energy Service Providers (ESPs) were represented,~~
 - ~~Meter Data Management Agents⁵ (MDMAs) were used~~
 - ~~Time periods of direct access sign up and returns were covered~~
 - ~~Contract expirations/terminations occurred~~~~
- ~~A statement of who conducts the Scheduling Coordinator Self-Audit and a brief discussion of their background and qualifications~~
- ~~A discussion of how the Scheduling Coordinator Self-Audit is accomplished, activities to be tested, the source of information, and a proposed timeline for completion~~
- ~~Any additional information believed to be relevant for CAISO's review of the Scheduling Coordinator Self-Audit plan, such as major changes since the last Scheduling Coordinator Self-Audit, or results of other internal audits or reviews~~

The completed Scheduling Coordinator Self-Audit report must include as a minimum, four-five components:

- Scheduling Coordinator's management assertion that they have completed the appropriate audits and tests and that they have reviewed the results. Based on their review, they assert that tariff requirement 10.3.10.1 was completed for that year and that they have taken all reasonable and necessary actions to ensure the accuracy and integrity of the Settlement Quality Meter Data provided to the ISO.
- A description of the entities they represent in the ISO market (such as LSEs, ESPs, Cities, Direct Access Customers, etc.), as well as the name of the applicable Local Regulatory Authority.
- A description of the Settlement Quality Meter Data process and controls in place to assure compliance.
- A description of the audits and tests performed and who performed the activities.
- Explanation of any errors identified and corrective actions taken to prevent recurrence. If significant issues were identified in the previous audit, a discussion of the corrective actions taken to remedy the issues should also be included.

⁵ ~~A Meter Data Management Agent (MDMA) is an entity that has qualified to read meters, validate Meter Data, and estimate missing data to make available to others for use in various applications as defined by the CPUC or Local Regulatory Authority.~~

Supporting data does not need to be provided with the Audit Report, however, the ISO maintains the right to ask for and review any material used to complete the Scheduling Coordinator's Audit. Details on the audit report can be found on the Metering and Telemetry page of the ISO website.

- ~~For Scheduling Coordinators that participated in previous year's Scheduling Coordinator Self-Audit, documentation from the previous year's Scheduling Coordinator Self-Audit findings and any actions taken as a result of CAISO recommendations~~
- ~~Review of the process controls in place for activities involving the SQMD processing level~~
- ~~Verification and testing of the process controls in place at the SQMD processing level and the testing done by selecting an appropriate sample~~
- ~~Identification of the root cause for all identified Scheduling Coordinator Self-Audit findings and the actions taken to prevent recurrence~~

~~A Scheduling Coordinator Self-Audit checklist is available to assist Scheduling Coordinators in completing their Scheduling Coordinator Self-Audit report. The Scheduling Coordinator Self-Audit checklist is located on the CAISO Website at:~~

~~<http://www.caiso.com/docs/2005/10/01/200510011610035819.html>~~

6.3.2 Audit & Testing by CAISO

CAISO Tariff Section 10.3.10.2

Subject to any applicable Local Regulatory Authority requirements, the Metering Facilities and data handling and processing procedures of Scheduling Coordinators and Scheduling Coordinator Metered Entities are subject to audit and testing by the CAISO or a CAISO Authorized Inspector. Subject to any applicable Local Regulatory Authority requirements, the CAISO has the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the Scheduling Coordinator, Scheduling Coordinator Metered Entity or a CAISO Authorized Inspector engaged by the Scheduling Coordinator, Scheduling Coordinator Metered Entity or the CAISO to carry out those audits or tests.

7. Meter Service Agreements

Welcome to the *Meter Service Agreement* section of the *BPM for Metering*. In this section you will find the following information:

- A description of the Meter Service Agreement for CAISO Metered Entities
- A description of the Meter Service Agreement for Scheduling Coordinators for Scheduling Coordinator Metered Entities
- A description of the Scheduling Coordinator Agreement
- A description of the Qualifying Facility Participating Generator Agreement

7.1 CAISO Metered Entities

CAISO Tariff Appendix B.6

A CAISO Metered Entity must sign a Meter Service Agreement for CAISO Metered Entities MSA CAISOME with CAISO. CAISO establishes Meter Service Agreements with CAISO Metered Entities for the collection of Revenue Quality Meter Data. Such agreements specify that CAISO Metered Entities make available to CAISO's RMDAPS, Revenue Quality Meter Data meeting the requirements of this BPM. The Meter Service Agreement and this BPM specify the format of Meter Data to be submitted, which is identified by Transmission Owner, Distribution System, PNode, CAISO Controlled Grid interface point and other information reasonably required by CAISO. A Meter Service Agreement entered into by a CAISO Metered Entity only applies to those entities that the CAISO Metered Entity represents. Meter Service Agreements identify other authorized users that are allowed to access the SQMD relating to the CAISO Metered Entities. The CAISO Metered Entity must amend the MSA CAISOME to identify any new authorized users. A *pro forma* version of the Meter Service Agreement for ISO Metered Entities is set forth in Appendix B.6 of the CAISO Tariff and can be found on CAISO Website at: www.caiso.com.

7.2 Scheduling Coordinator Metered Entities

CAISO Tariff Appendix B.7

A Scheduling Coordinator for a Scheduling Coordinator Metered Entity must sign a Meter Service Agreement for Scheduling Coordinators (MSA SC) with the CAISO. The Scheduling Coordinator for a Scheduling Coordinator Metered Entity is responsible for providing SQMD for Scheduling Coordinator Metered Entities it represents. Such agreements specify that

Scheduling Coordinators require their Scheduling Coordinator Metered Entities to adhere to the meter requirements of the CAISO Tariff applicable to Scheduling Coordinators for Scheduling Coordinator Metered Entities, which include those set forth in Section 6 of this BPM. A Meter Service Agreement entered into by a Scheduling Coordinator applies to the Scheduling Coordinator only in its capacity as Scheduling Coordinator for those Scheduling Coordinator Metered Entities. A *pro forma* version of the Meter Service Agreement for Scheduling Coordinators is set forth in Appendix B.7 of the CAISO Tariff and can be found on the CAISO Website at: www.aiso.com.

7.3 Scheduling Coordinator Agreement

CAISO Tariff Appendix B.1

Prior to commencing the process to become certified to provide SQMD for Scheduling Coordinator Metered Entities, a Scheduling Coordinator must sign a Scheduling Coordinator Agreement. A *pro forma* version of the Scheduling Coordinator Agreement is set forth in Appendix B.1 of the CAISO Tariff and can be found on the CAISO Website at: www.aiso.com.

7.4 Qualifying Facility Participating Generator Agreement

CAISO Tariff Appendix B.3

If a Participating Generator has a Qualifying Facility and wishes to be eligible for the requirements applicable to metering for QFs specified in Section 11 of this BPM, the Participating Generator must sign a Qualifying Facility Participating Generator Agreement. A *pro forma* version of the Qualifying Facility Participating Generator Agreement is set forth in Appendix B.3 of the CAISO Tariff and can be found on the CAISO Website at: www.aiso.com.

8. Exemptions

Welcome to the *Exemptions* section of the *BPM for Metering*. In this section you will find the following information:

- A description of the exemption guidelines
- A description of the exemption application procedure
- A description of the permitted exemptions

CAISO Tariff Sections 10.2.12 and 10.4.1

CAISO has the authority to grant exemptions from certain CAISO metering standards for a CAISO Metered Entity that is subject to CAISO metering standards. A CAISO Metered Entity with a temporary⁶ exemption must provide site specific SQMD to CAISO in accordance with its meter service agreement, the CAISO Tariff and this BPM. A Generator with a Generating Unit connected directly to a UDC Distribution System that sells its entire output to the UDC in which the Generating Unit is located is not subject to the CAISO Metered Entity audit, testing or certification requirements of CAISO.

In addition to exemptions granted to individual entities, CAISO may grant exemptions that apply to a class of entities. CAISO may grant class exemptions whether or not it has received any application for an exemption.

8.1 Guidelines

CAISO Tariff Section 10.4.2

CAISO uses the following guidelines when considering applications for exemptions from compliance with the CAISO Tariff.

8.1.1 Publication of Guidelines

CAISO Tariff Section 10.4.2 (a)

CAISO publishes the general guidelines that it uses when considering applications for exemptions so as to achieve consistency in its reasoning and decision-making and to give prospective applicants an indication of whether an application receives favorable consideration. The Metering Exemption Guidelines are located on CAISO Website at:

⁶ 60 days or less.

<http://www.caiso.com/docs/2005/10/01/200510012104433453.html>.

8.1.2 Metering Exemption Publication

CAISO Tariff Section 10.4.2(b)

CAISO publishes on the CAISO Website a description of each granted request it receives for an exemption and publishes the request and the reason for the exemption. Exemption Publications are located on the CAISO website at:

<http://www.caiso.com/docs/2005/10/01/2005100119040822976.html>

8.2 Request for Exemption Procedure

CAISO Tariff Section 10.4.3

All requests to CAISO for exemptions from compliance with the requirements of the CAISO Tariff must be made in writing ~~addressed to the Manager of Operations Data and Compliance and Support, Operations~~. CAISO confirms receipt of each request it receives within three Business Days of receiving the request. CAISO decides whether to grant the exemption within five Business Days of receiving the request. At any time during that period, CAISO may require the requester to provide additional information in support of its request. The requester must provide such additional information to CAISO within five Business Days of receiving the request for additional information or within such other period as CAISO notifies the requester. If CAISO makes a request for additional information more than five Business Days after the date on which it received the request, CAISO has an additional five Business Days after receiving that additional information in which to consider the request. If the requester does not provide the additional information requested, CAISO may refuse the request in which case it notifies the requester that its request has been rejected for failure to provide the additional information.

CAISO Tariff Section 10.3.18.4

The request submitted to CAISO must provide:

- A detailed description of the exemption sought and the facilities to which the exemption applies
- A detailed statement of the reason for seeking the exemption (including any supporting documentation)
- Details of the entity to which the exemption applies

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- Details of the location to which the exemption applies
 - Details of the period of time for which the exemption applies (including the proposed start and finish dates of that period)
 - Any other information requested by CAISO

8.3 Permitted Exemptions

CAISO Tariff Section 10.4.4

This section provides a summary of the exemptions that are available. These exemptions fall into two broad categories:

- Exemptions from providing Meter Data directly to RMDAPS
- Exemptions from meter standards

8.3.1 Exemptions from Providing Meter Data Directly to RMDAPS

CAISO Tariff Section 10.4.4.1

CAISO has the authority under the CAISO Tariff to exempt CAISO Metered Entities from the requirement to make Meter Data directly available to CAISO via RMDAPS. CAISO may, at its discretion, grant such an exemption where it considers the requirement to install communication links (or related facilities) between the CAISO Metered Entity and CAISO's secure communication system to allow CAISO to directly poll that CAISO Metered Entity is impractical or uneconomic.

8.3.2 Exemptions from Meter Standards

CAISO Tariff Section 10.4.4.2

CAISO has the authority under the CAISO Tariff to exempt CAISO Metered Entities from the requirement to comply with the meter standards referred to in the CAISO Tariff.

9. Other Metering Configurations

Welcome to the *Other Metering Configurations* section of the *BPM for Metering*. In this section you will find the following information:

- A description of the metering configuration for MSSs
- A description of the metering configuration for Dynamic System Resources
- A description of the metering configuration for utility Service Areas that request separate UFE calculation
- A description of the metering configuration for Participating Loads

Various metering configurations are allowed in the CAISO Markets. This section describes some of these configurations, which differ from the traditional Generating Unit or Load schema.

9.1 Metered Subsystems

CAISO Tariff Appendix A

A Metered Subsystem (MSS) is essentially a separate operating area within the CAISO Control Area that is encompassed by CAISO certified revenue quality meters at each interface point with the CAISO Controlled Grid or with any other portion of the interconnected electric grid in the CAISO Control Area. CAISO certified revenue quality meters are also required for each interface point with all Generating Units within the MSS.

CAISO Tariff Section 4.9.11.1.1

CAISO and each MSS Operator each have the right, if mutually agreed, on reasonable notice to install or to have installed equipment (including metering equipment) or other facilities on the property of the other. This right is permitted to the extent that such installation is necessary for the installing party to meet its service obligations, but prohibited to the extent that doing so would have a negative impact on the reliability of the service provided by the party owning the property.

CAISO Tariff Section 4.9.12.2.5

Each MSS must install CAISO certified meters on each individual Generating Unit that is aggregated into a System Unit.

9.2 Dynamic System Resource Meters

CAISO Tariff Appendix X

A Dynamic System Resource is a resource located outside the CAISO Controlled Area Grid that is capable of submitting a Dynamic Schedule that can change in Real-Time. A Dynamic Schedule is a telemetered reading or value which is updated in Real-Time and which is used as a schedule in the CAISO Energy Management System calculation of Area Control Error and the integrated value of which is treated as a schedule for interchange accounting purposes. A Dynamic Schedule is commonly used for “scheduling” jointly owned generation to or from another Control Area.

Because of the unique nature of this configuration, a Scheduling Coordinator representing a resource that wants to become a Dynamic System Resource needs to contact a CAISO account manager for specific metering requirements.

9.3 Metering for Separate UFE Calculations

CAISO Tariff Section 10.2.1.1 and Appendix A

UDCs and other utilities with CAISO certified metering at points of connection of their Service Areas with the systems of other utilities can request and receive separately calculated UFE. Utilities meeting these requirements are CAISO Metered Entities for all purposes of the CAISO Tariff and this BPM.

UDCs and other utilities with a separate UFE calculation will schedule Load to the LAP; however, the metered Load will be assigned to the appropriate UDC for purposes of UFE calculation.

9.4 Metering for Participating Load Program

CAISO Tariff Section 4.7

The CAISO’s Participating Load program allows Loads to utilize Curtailable Demand to provide Non-Spinning Reserve and Imbalance Energy in the CAISO’s Markets. Participating Loads that are CAISO Metered Entities must use CAISO certified metering as defined in the MSA CAISOME, the CAISO Tariff and this BPM. Scheduling Coordinator Metered Entities that participate in the Participating Load program must meet the requirements of the CAISO Participating Load Technical Standards that are posted on the CAISO Website at:

<http://www.aiso.com/docs/2001/01/22/200101221153242073.pdf>

10. Station Power Program

Welcome to the *Station Power Program* section of the *BPM for Metering*. In this section you will find the following information:

- A description of the eligibility requirements for self-supply of Station Power
- A description of the application process to self-supply Station Power
- A description of the monitoring and review of Station Power Portfolio applications undertaken by the CAISO
- A description of the self-supply verification process and CAISO charges that apply
- A description of the metering requirements for self-supply of Station Power
- A description of the provision of data to UDCs or MSS Operators

10.1 Station Power Program Overview

Station Power is the Energy used to operate auxiliary equipment and other Load that is directly related to the production of Energy by a Generating Unit (e.g., heating and lighting for offices located at the plant). FERC has established a policy that allows a single entity that owns one or more Generating Units to self-supply Station Power over a monthly Netting Period using Energy generated on-site or remotely. Through the CAISO Station Power Program, Generators can convert their Station Power from retail service to wholesale service.

Station Power may be supplied in three ways:

- **On-Site Self-Supply** – Energy from a Generating Unit that is deemed to have self-supplied all or a portion of its Station Power Load without use of the CAISO Controlled Grid during the Netting Period⁷.
- **Remote Self-Supply** – Positive Net Output from generating resources in a Station Power Portfolio that is deemed to have self-supplied Station Power Load of other Generating Units in the Station Power Portfolio during the Netting Period, where such supply requires the use of the CAISO Controlled Grid.
- **Third Party Supply** – Energy that is deemed to have been purchased from third parties to supply Station Power Load during the Netting Period.

⁷ Netting Period is one calendar month.

10.2 Eligibility

Only Generating Units that operate under the terms of a PGA, QF PGA or MSS Agreement are eligible to self-supply Station Power service. A Qualifying Facility (QF) that is not bound to the CAISO Tariff is not eligible to self-supply Station Power.

Station Power may be self-supplied by a single corporate entity, government agency, or joint powers agency or other legal entity organized under the laws of the State of California. A Station Power Portfolio may not include any facilities that are owned by the owner's corporate affiliates.

If an entity owns a jointly owned Generating Unit it may remotely self-supply the Station Power of its other Generating Units up to the amount of its entitlement to Energy from the jointly-owned Generating Unit provided that:

- The entity has the right to call upon that Energy for its own use
- The Energy entitlement is not characterized as a sale from the jointly owned Generating Unit to any of its joint owners

10.3 Limitations

Self-supply of Station Power is strictly voluntary. Nothing in the CAISO Tariff or this BPM is intended to:

- Preclude a Generator from purchasing Station Power pursuant to an applicable retail rate or tariff
- Supersede otherwise applicable jurisdiction of a Local Regulatory Authority, except in the event of a conflict between federal and state tariff provisions, in which case the federal tariff provisions control

10.4 Applications to Self-Supply Station Power

An application to establish a Station Power Portfolio or to modify the configuration of Station Power meters or the generating facilities included in a Station Power Portfolio must be submitted according to the process specified by the CAISO and includes the following information:

- One-line diagrams clearly showing the location and ownership of all Generating Units and Station Power meters, their connection to the CAISO Controlled Grid or Distribution System, and the status of breakers and switchgear for normal system operation
- Identification of any generating facilities outside the CAISO Control Area, used to provide Remote Self-Supply of Station Power within the proposed Station Power Portfolio. No loads associated with generating facilities outside the CAISO Control Area are supplied under the Station Power Program
- Certification that the applicant is the sole owner of all generating facilities proposed to be included in the Station Power Portfolio, and that the applicant has the right to call on Energy for its own use from its ownership share of any jointly owned facilities that are proposed to be used to self-supply Station Power
- Demonstration that each Station Power meter is certified in accordance with the CAISO Tariff
- Verification that each Station Power meter is subject to a Meter Service Agreement for CAISO Metered Entities, and that each Generating Unit is bound to the CAISO Tariff by a PGA, QF PGA, or MSS Agreement
- Verification that the applicant has arranged for terms of service with the responsible UDC or MSS Operator for the use of any distribution facilities required to self-supply Station Power
- A Station Power Portfolio application fee

The Station Power Portfolio Application Form is located on the CAISO Website at:

<http://www.caiso.com/17c8/17c89da01e60.html>

10.5 CAISO Monitoring & Review

The CAISO takes the following actions with respect to each application to establish a Station Power Portfolio:

- Within 10 Business Days from the receipt of a completed application, the CAISO will post information under "Station Power Portfolio Applications In Progress" that includes the name of the Generating Unit, the date received, the Scheduling Coordinator, the UDC and the status of the application.

- Provides the appropriate UDC or MSS Operator and the Local Regulatory Authority with one-line diagrams and other information regarding each application.
- Verifies that each Station Power meter is certified in accordance with the CAISO Tariff. All Load served by each Station Power meter must be consistent with the definition of Station Power, and any ineligible Load must have separate metering in place. Under no circumstances may ineligible Loads be served through a Station Power meter.
- Makes a determination in consultation with the UDC or MSS Operator and the Local Regulatory Authority on the factual question of whether distribution facilities are involved in the requested self-supply of Station Power. Any disputes regarding such determinations are subject to the CAISO ADR Procedures of the CAISO Tariff.
- Verifies metering schemes and assigns unique Load identifiers consistent with the CAISO data templates and VEE procedures that the Scheduling Coordinator responsible for each resource is required to use for scheduling and Settlement.
- Posts on the CAISO Website within 10 Business Days after the start date for the implementation of a Station Power Portfolio a listing of the specific participating Station Power Generating Units located in the CAISO Control Area, and any generating facilities outside the CAISO Control Area, that compose each Station Power Portfolio, and that are eligible to participate in the self-supply of Station Power in accordance with the CAISO Tariff.

10.6 Self-Supply Verification & CAISO Charges

Self-supply of Station Power is subject to verification and CAISO charges.

At the end of each Netting Period, the CAISO calculates the Net Output for each Generating Unit in the Station Power portfolio. If the Net Output is positive, then all Station Power associated with that Generating Unit, other than Load netted in accordance with the CAISO Tariff, is served by On-Site Self-Supply. Any positive Net Output from facilities in the Station Power Portfolio is available to provide Remote Self-Supply to any Generating Unit with negative Net Output. If the available Remote Self-Supply is less than the aggregate negative Net Output in the Station Power Portfolio, then the shortfall is deemed to have been served by Third Party Supply. The CAISO incorporates these determinations in its accounting and billing for the Netting Period by reassigning Station Power to unique Load identifiers for Remote Self-Supply and Third Party Supply, as required. An example of this process to reallocation Station Power Load to the Station Power Load IDs is located in Attachment F of this BPM.

Station Power that is not eligible for permitted netting pursuant to this Section 10 or Section 4.1 of this BPM should be scheduled in accordance with the CAISO Tariff and is assessed all charges applicable to metered Demand under the CAISO Tariff, except as provided in this BPM⁸.

In the event that CAISO has to reallocate Station Power Meter Data from the On-Site Self-Supply Load ID to either the Remote Self-Supply Load ID or the Third Party Supply ID, CAISO charges a monthly fee per Station Power Load ID to the portfolio owner's Scheduling Coordinator. The monthly reallocation will occur and be represented on the Recalculation Settlement Statement following the reallocation.

For example, if Station Power Portfolio contains two Station Power meters and both Remote Self-Supply and Third Party Supply is attributed to each Station Power meter, then the CAISO must reallocate Meter Data from the two On-Site Self-Supply Load IDs to the two Remote Self-Supply Load IDs and the two Third Party Load IDs. If the CAISO were charging a \$200 monthly fee, the portfolio owner's Scheduling Coordinator would receive four \$200 charges for this Meter Data reallocation for this month. The Scheduling Coordinator for the Station Power Portfolio is responsible for all CAISO Settlement charges for Load reported under the On-Site Self-Supply Load ID and the Remote Self-Supply ID. The UDC's Scheduling Coordinator is responsible for all CAISO Settlement charges for Load reported under the Third Party Load ID. Consistent with FERC precedent, Station Power Load to which On-Site Self-Supply is attributed are not subject to the CAISO's transmission Access Charge (TAC), while Station Power Load to which Remote Self-Supply and Third Party Supply is attributed are subject to the transmission Access Charge.

10.7 Station Power Portfolio Set-Up

In order to self-supply Station Power, a Generating Unit must be subject to a Meter Service Agreement for CAISO Metered Entities. If the Load associated with a Station Power meter is intended to be self-supplied only by On-Site Self-Supply, then two Load IDs are associated with the meter. The default Load ID for each meter is the "On-Site Self-Supply Load ID", which is assigned to the portfolio owner's Scheduling Coordinator.

The second Load ID that is assigned to each Station Power meter is the "Third Party Supply Load ID", which is associated with the Scheduling Coordinator of the UDC responsible for retail service. This Third Party Supply Load ID is used by CAISO after the Netting Period to identify Station Power Load for which the portfolio owner failed to self-supply Station Power. No Meter Data is reported under the Third Party Supply Load ID until a determination is made at the end

⁸ This section 4.1 is subject to change as a result of FERC orders in FERC docket No. ER05-849 regarding Amendment No. 68 to the CAISO Tariff adding the Station Power Protocol, which matter is currently the subject of a stay and request for rehearing.

of the Netting Period about whether or not the Generation in the Station Power Portfolio was sufficient to self-supply the Station Power Load in the Station Power Portfolio. If Station Power Load exceeds the available Generation, then CAISO shifts a portion of reported Load to the Third Party Supply Load ID. Any reallocated Third Party Supply Load will appear on the Scheduling Coordinator's Recalculation Settlement Statement following the reallocation. As explained below, the CAISO requires that the UDC's Scheduling Coordinator not schedule any Load using the Third Party Supply Load ID.

If there are one or more Generating Units in the Station Power Portfolio that could remotely self-supply Load served by a Station Power meter, then a "Remote Self Supply Load ID" is also specified for that meter. The Remote Self-Supply Load ID facilitates settlement of transmission charges and is associated with the portfolio owner's Scheduling Coordinator. The portfolio owner's Scheduling Coordinator is not allowed to schedule using the Remote Self Supply Load ID, but exclusively schedules any Load using the On-Site Self Supply Load ID.

The UDC's Scheduling Coordinator should not schedule to the Third Party Supply Load ID. Since the Load that is reported under the Third Party Supply Load ID for any interval is not determined until after the end of the month, it is difficult or impossible to schedule such Load accurately.

10.8 Provision of Data to UDC or MSS Operator

At T+7 Business Days from the last day of the month, the CAISO posts to the Settlement Quality Meter Data Systems the amount of On-Site Self-Supply, Remote Self-Supply, and Third Party Supply serving Station Power in five-minute intervals for the previous month to allow the UDC or MSS Operator to assess charges, if any, under the applicable retail tariff(s). This data is preliminary Meter Data and is not considered actual Settlement Quality Meter Data until T+48 business days.

11. Qualifying Facility (QF) Metering

Welcome to the *Qualifying Facility (QF) Metering* section of the *BPM for Metering*. In this section you will find the following information:

- A description of the inapplicability of CAISO metering requirements to Regulatory Must-Take Generation
- A description of the eligibility requirements for net metering for QFs
- A description of the metering requirements pursuant to the QF PGA

11.1 Inapplicability of CAISO Metering Requirements to Regulatory Must-Take Generation

CAISO Tariff Section 10.1.3.3

Generating Units that are QFs and that operate under the terms of an Existing QF Contract or other power purchase agreement (“PPA”) entered into pursuant to the Public Utility Regulatory Policies Act of 1978 (“PURPA”) are not subject to CAISO metering requirements. Instead, these QFs qualify as Regulatory Must-Take Generation. The metering requirements applicable to Regulatory Must-Take Generation are those set forth in the Existing QF Contract or other PURPA PPA.

11.2 QF Eligibility for Net Metering

QF Generating Units not operating under the terms of an Existing QF Contract or other PURPA PPA are subject to the metering requirements of the CAISO Tariff prohibiting the net metering of Generation and Load except as specified in the QF PGA. Generating Units that are QFs and that operate under the terms of a QF PGA are eligible for net metering treatment. A QF that is not bound to the CAISO Tariff is not eligible for net metering, unless the QF is Regulatory Must-Take Generation and the net metering is specified in its Existing QF Contract or other PURPA PPA.

11.2.1 Demonstration of QF Status

In order to be eligible to execute the QF PGA and receive net metering treatment, a Participating Generator must demonstrate to the CAISO that its Generating Unit has QF status pursuant to PURPA. The Participating Generator must provide the CAISO a copy of the FERC order providing Qualifying Facility status to the Net Scheduled QF or any other evidence of QF status determined to be acceptable by the CAISO.

11.2.2 Demonstration of Standby Service or Curtailment of Self-Provided Load

In order to be eligible to execute the QF PGA and receive net metering treatment, a Participating Generator must demonstrate to the CAISO that (a) the Self-provided Load of the Participating Generator that is served by the Net Scheduling QF either has contracted for and continue through the term of the QF PGA to have secured standby service from a UDC or MSS Operator under terms approved by the Local Regulatory Authority or FERC, as applicable, or (b) the Self-provided Load is curtailed concurrently with any Outage of the Generation serving that Self-provided Load in an amount sufficient to cover that Outage. The Participating Generator must provide the CAISO a copy or a summary of the primary terms of any agreement for standby service with a UDC or MSS Operator or any other evidence of the foregoing determined to be acceptable by the CAISO.

11.2.3 Execution of a QF PGA

The *pro forma* version of the QF PGA is set forth in Appendix B.3 of the CAISO Tariff. Once the CAISO has received the evidence required by Sections 11.2.1 and 11.2.2 or has otherwise determined that the Participating Generator has met the requirements of those provisions, the CAISO prepares a QF PGA for execution by the Generator. Once the QF PGA has become effective, the net metering treatment for the QF is implemented. If the Participating Generator executes a *pro forma* version of the QF PGA, the net metering can be implemented immediately.

11.3 Permitted Netting for Net Scheduled QFs

Pursuant to the QF PGA, net metering is permitted for the Demand of Self-provided Load that is (i) served by a Net Scheduled QF and (ii) is electrically located on the same side of the Point of Demarcation. The Participating Generator may satisfy the provisions of the CAISO Tariff for the installation of meters by installing at the Point of Demarcation meters for the purpose of recording the net impact of the Net Scheduled QF upon the CAISO Controlled Grid; provided that the installed meters satisfy the technical functional and performance requirements for meters set forth in the CAISO Tariff and this *BPM for Metering*.

12. Proxy Demand Resources ~~and Reliability Demand Response Resources~~

Welcome to the *Demand Response* section of the *BPM for Metering* featuring the *Proxy Demand Resource* ~~and Reliability Demand Response Resource~~ programs. In this section you will find the following information:

- An introduction to Proxy Demand Resources and description of the program
- ~~➤ An introduction to Reliability Demand Response Resources and description of the program~~
- An overview of business processes associated with ~~both the~~ Proxy Demand Resources ~~and Reliability Demand Response Resources~~
- An introduction to the Demand Response Provider Agreement and its process
- An introduction to the Demand Response System (DRS)
- A description of the pre-market registration process for Proxy Demand Resources ~~and Reliability Demand Response Resources~~
- A description of post market Meter Data submittal, baseline and Demand Response Energy Measurement
- A description of the monitoring metrics in place for Demand Response Resources

12.1 Proxy Demand Resource ~~Program-Product and Reliability Demand Response Resource~~ Overview

The CAISO developed the Proxy Demand Resource (PDR) ~~program-product~~ to increase Demand response participation in the ISO's wholesale Energy and Ancillary Services markets. Additionally, PDR will help in facilitating the participation of existing retail demand response into these markets.

~~The CAISO developed the Reliability Demand Response Resource (RDRR) program in order to further increase demand response participation in the ISO markets and to facilitate integration into the ISO market of existing emergency-triggered retail demand programs and newly~~

~~configured demand response resources that have reliability triggers and desire to be dispatched only under certain system conditions.~~

~~Both PDR and the RDRR programs~~ provides the capability to permit an aggregator of retail customers to bid demand response on behalf of retail customers directly into the ISO's organized markets to the extent permitted by applicable laws and regulations regarding retail customers

In general, a PDR ~~and RDRR~~ is a combination of Load scheduled by a Load Serving Entity at the Default LAP and a Bid to curtail submitted by the Demand Response Provider (DRP) using a separate proxy generator with a distinct Resource ID. The LSE and the DRP may be the same or different entities.

A PDR may participate in the Day-Ahead, Real-Time, and Non-Spinning Reserve markets like a generator resource. ~~A RDRR may participate in the Day Ahead market and in the Real Time Markets like a generator resource, but may not submit Energy Self Schedules, may not Self-Provide Ancillary Services, and may not submit RUC Availability or Ancillary Service bids.~~

A PDR ~~and RDRR~~ will be modeled as a proxy generator in the CAISO Full Network Model and is bid as an aggregate generator which may be as small as a single node or as large as a CAISO defined Sub-LAP. The scheduling, Dispatch, and Settlement of the PDR ~~and RDRR~~ will be as a proxy generator resource on the distinct Resource ID, and the scheduling of the LSE base Load will remain at the Default LAP.

Settlements for Energy provided by Demand Response Providers from Proxy Demand Resources ~~and Reliability Demand Response Resources~~ shall be based on the Demand Response Energy Measurement for the Proxy Demand Resource ~~or Reliability Demand Response Resource~~ (CAISO Tariff Section 11.6.1), where the PDR Energy Measurement is defined as the Energy quantity calculated by comparing the Customer Baseline of a Proxy Demand Resource ~~or Reliability Demand Response Resource~~ against its actual underlying Load for a Demand Response Event. The Demand Response Energy Measurement for the Proxy Demand Resource ~~or Reliability Demand Response Resource~~, representing the curtailed portion of the resource's Load, is settled directly with the DRP's SC. For the purposes of settling Uninstructed Imbalance Energy of a Load Serving Entity, the amount of Demand Response Energy Measurement delivered by a Proxy Demand Resource ~~or Reliability Demand Response Resource~~ will be added to the metered Demand quantity of the Load Serving Entity's Scheduling Coordinator's Load Resource ID with which the Proxy Demand Resource ~~or Reliability Demand Response Resource~~ is associated. (CAISO Tariff Section 11.5.2.4).

The following summarizes the Proxy Demand Resource ~~program-product~~ design attributes:

- A DRP may participate in the CAISO Markets separately from the LSE;
- The LSE and Utility Distribution Company (UDC) has the opportunity to review location information for a registration requested by a DRP;
- A PDR is eligible to participate in the Day-Ahead Energy market, Real-Time Energy market and Ancillary Services market to provide Non-Spinning Reserve;
- ~~A RDRR is eligible to participate in the Day-Ahead Energy market and Real-Time Energy market;~~
- The DRP's SC submits a PDR ~~or RDRR~~ bid to curtail Load and receive Automated Dispatch System (ADS) instructions as if it were a generator. The PDR ~~or RDRR~~ is bid and settled at a PNode (which could be a specific location or an aggregation of PNodes) and Settlement occurs directly between the CAISO and the DRP's Scheduling Coordinator;
- The LSE continues to forecast and schedule its total Load at the Default LAP;
- Performance of the Proxy Demand Resource ~~or Reliability Demand Response Resource~~ is generally determined through a pre-determined baseline calculation using the last 10 non event days with a look back window of 45 days and a bidirectional morning adjustment capped at 20%;
- A Demand Response Provider representing a PDR ~~or RDRR~~ may submit a written application to the CAISO for approval of a methodology for statistically derived meter data, referred to in this BPM as Generation Data, for the ~~RDRR or~~ PDR that consists of a statistical sampling of Energy usage data. (CAISO Tariff Section 10.1.7)
- The CAISO will adjust the Settlement of the LSE based on the measured performance of the Proxy Demand Resource ~~or Reliability Demand Response Resource~~ to ensure there is no double payment for the demand response;

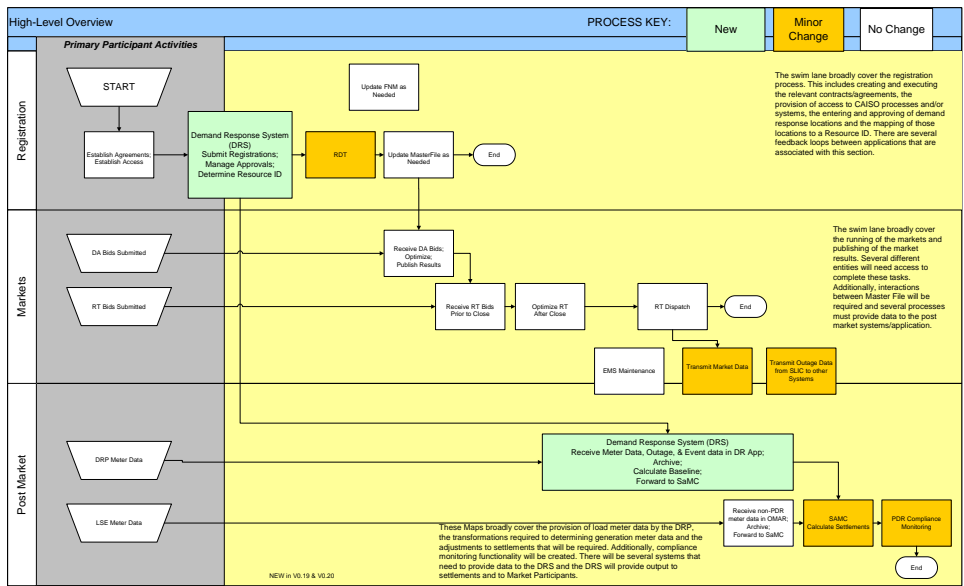
Demand response performance will be monitored by the CAISO through a robust measurement and verification plan to ensure that demand response paid for was actually provided to the market.

The *BPM for Metering* addresses several of these design attributes; however, additional BPMs have changed to reflect these PDR ~~and RDRR~~ design attributes. The following BPMs should be reviewed for further information not provided within this section of the *BPM for Metering*.

Ref#	BPM
1	Managing Full Network Model
3	Market Instruments
4	Outage Management
6	Market Operations
7	Compliance Monitoring
9	Scheduling Coordinator Certification & Termination
12	Definitions & Acronyms
13	Settlements & Billing

12.2 Proxy Demand ~~and Reliability Demand Response~~ Resource Registration Process Overview

The following diagram is provided to illustrate the PDR ~~and RDRR~~ process from registration through participation in the CAISO Markets into the CAISO's post market processing including metering, Settlements and compliance monitoring.



The objectives of the following sections are to describe process and application impacts due to Proxy Demand Resource ~~and Reliability Demand Response Resource~~ providing Market Participants the required information needed to participate in either the PDR program product.

12.3 Executing a ~~Demand—ResponseProxy Demand AgreementResource Agreement~~

To initiate a ~~Demand Response Agreement (DRA) Proxy Demand Resource Agreement (PDRA)~~, an information request sheet must be filled out completely and returned to the PDR Coordinator at pdr@caiso.com. Once the information request sheet has been reviewed for completeness, it will be sent to the CAISO's "Contracts" group for processing and to initiate the ~~Proxy Demand Resource Response~~ Agreement. The information request sheet for the ~~PDRA~~ can be obtained at www.caiso.com.

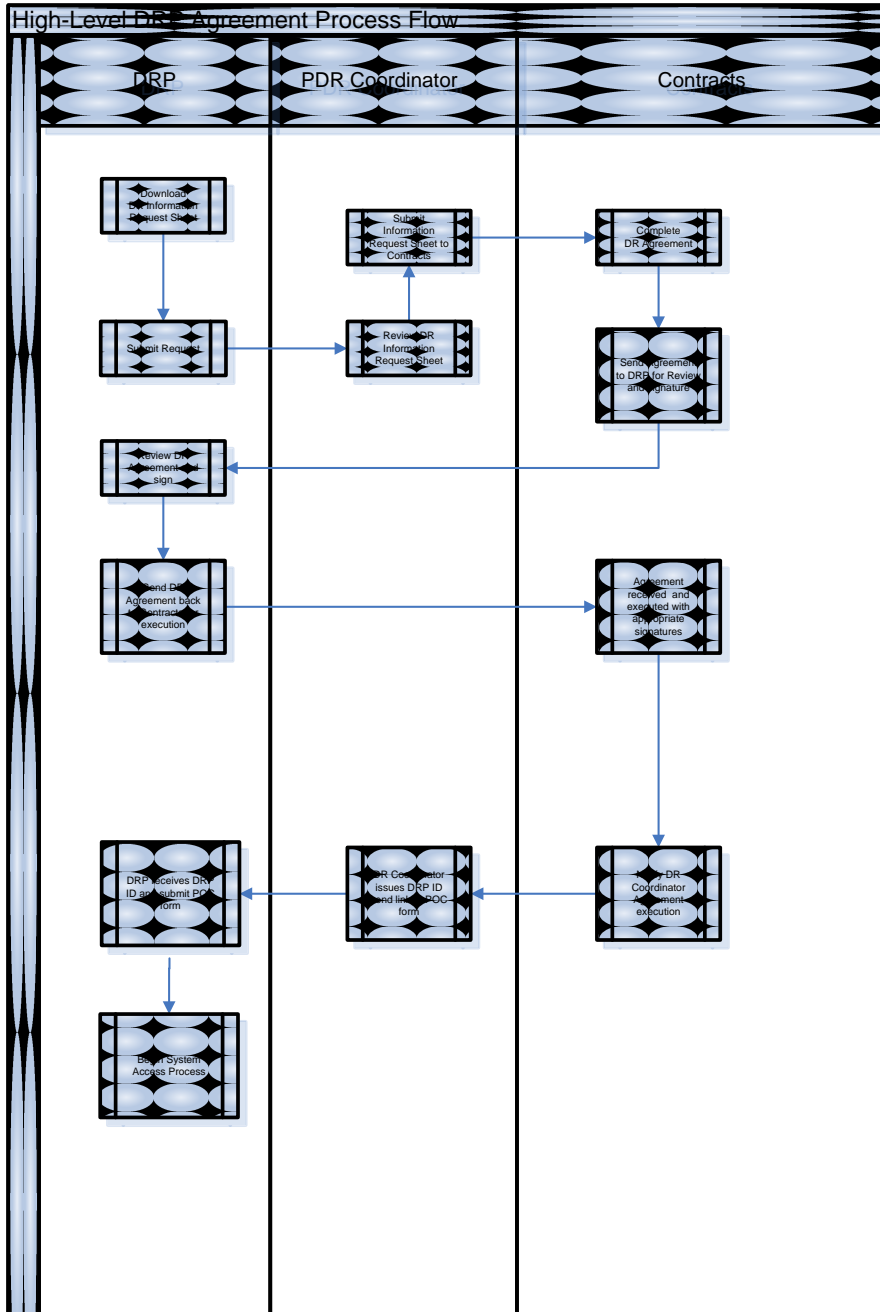
The pro forma ~~Proxy Demand Response-Response~~ Agreement is incorporated in Appendix B of the CAISO Tariff and can be obtained at the following location: www.caiso.com.

This agreement must be signed by a DRP and the CAISO and provided prior to requesting a PDR ~~or RDR~~ Resource ID. As with other CAISO agreements, the PDR agreement will bind the DRP to the CAISO Tariff. The agreement requires that the DRP use a certified Scheduling Coordinator (note, the SC must be certified to submit Settlement Quality Meter Data and have a Meter Service Agreement for Scheduling Coordinators with the CAISO) for all required tariff activities with the CAISO. The PDR agreement requires that the DRP have sufficient contractual relationships with the end use customers, LSE, and UDC and meet any Local Regulatory Authorities' requirement prior to participating in the CAISO Markets. This agreement process will have a fifteen (15) Business Day turnaround timeframe.

12.3.1 ~~12.3.1~~ Obtaining a DRP ID

Once the PDR Agreement has been executed, a DRP ID will be assigned by the CAISO. Notification of the assigned DRP ID will be sent initially via e-mail with a hard copy to the address of record. The DRP will also be given a link to the Point of Contact (POC) form located on www.caiso.com. The DRP will need to fill out the form, follow the submission directions, and e-mail a copy of the form to the PDR Coordinator at pdr@caiso.com. Once DRP has a DRP ID and has submitted the POC form, it can begin the User Application Access Request Form process to gain access to the Demand Response System.

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12.3.2 Use of a Certified Scheduling Coordinator

The CAISO requires the use of a certified Scheduling Coordinator to be eligible to transact business directly with the CAISO. A DRP could endeavor to become a certified Scheduling Coordinator or use an existing certified Scheduling Coordinator. It is important to note that the certification process for a new Scheduling Coordinator could take up to 120 days. A list of certified Scheduling Coordinators is maintained on the CAISO Website, under the reference tab of the operations center page. The DRP must enter into the appropriate contractual relationship with a certified Scheduling Coordinator and notify the CAISO of the Scheduling Coordinator it will be using; this can be done by a letter submitted to the attention of the CAISO's "External Affairs" group. By using a certified Scheduling Coordinator, all requirements, as outlined in the BPM for Scheduling Coordinator Certification and Termination, will be maintained by the Scheduling Coordinator and the DRP would not have to satisfy these requirements (for example: system requirements, credit requirements, demonstration of market proficiency, emergency procedures, and establishing qualifications to submit Settlement Quality Meter Data) independently.

12.4 Demand Response System

The Demand Response System (DRS) will manage the registration process, Meter Data submission, and will calculate Energy Measurement for those participating in the PDR ~~and RDRR programs~~product. Access to the system will require prior authorization and a digital certificate.

Please review the DRS user guide and additional training material located at www.caiso.com.

Due to the nature of the transactions performed by the DRP and Scheduling Coordinator in the CAISO Markets, the CAISO must have the ability to perform authentication and authorization for users. This requires a very specific process to obtain user access to CAISO systems. Therefore, the DRP and the SC must have their external point of contact on record with the CAISO. Through the external point of contact, the DRP and SC can request access to the needed system by submitting the User Application Access Request Form which can be found on the CAISO's information security page under the reference tab of the operations center on the CAISO Website. Access to the Demand Response System will be granted based on the information provided in the User Application Access Request Form

Since both the LSE and UDC for the underlying Load customers of a PDR ~~or RDR~~ need the ability to review the appropriate Load customer information during their registration process, the CAISO will need to maintain a list of the responsible individuals from the LSEs and UDCs that will perform the review of registration details in the Demand Response System. To ensure timely reviews, the CAISO will request that the LSEs and UDCs provide their contact information for the individuals that will perform the reviews.

The CAISO requests that, prior to entering their registration location information into the Demand Response System, Demand Response Providers contact the CAISO to ensure that the LSE of record for their registration locations already has access to the Demand Response System. If not, the DRP will need to provide the LSE contact information to the PDR coordinator at pdr@caiso.com.

12.5 Proxy Demand Resource ~~and Reliability Demand Response Resource~~ Registration

PDR ~~and RDRR~~ Resource ID

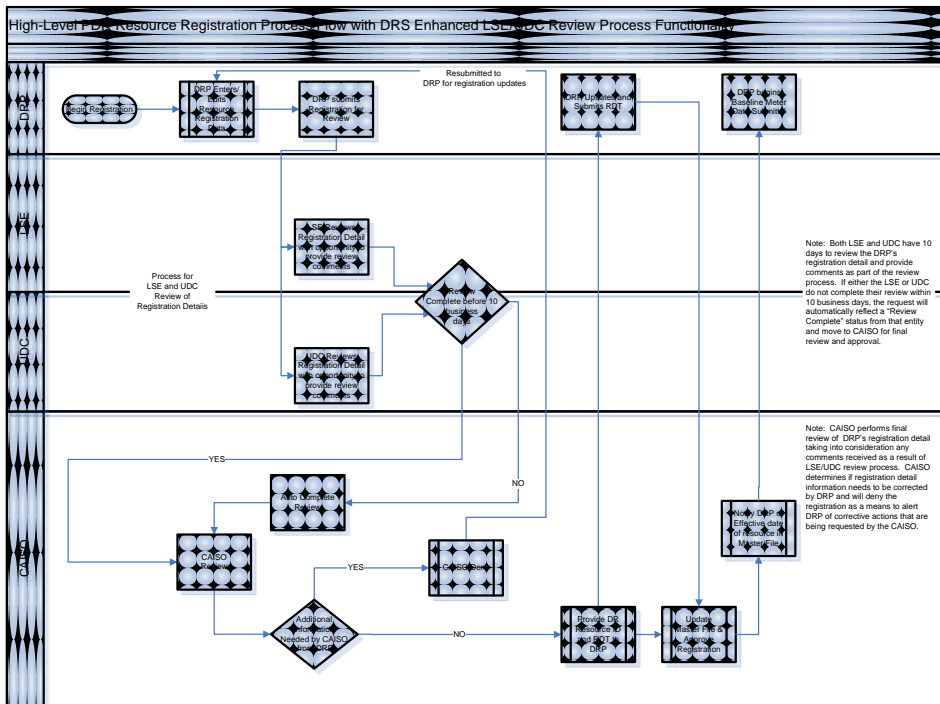
The PDR ~~and RDRR~~ Resource ID is a CAISO assigned Resource ID that represents a Proxy Demand Resource in the CAISO Markets. The PDR Resource ID will be used to bid, schedule, receive an award, receive Automated Dispatches System (ADS) instructions and be settled in the CAISO Markets. There are certain steps that must be accomplished by the DRP, LSE, UDC, and CAISO before the CAISO can assign a PDR Resource ID. The following explains the different types of PDR Resource IDs and describes the application, review, and assignment steps.

Registrations ~~and versus~~ PDR ~~or RDRR~~ Resource ID's Relationship

- Both pre-defined and custom Resource IDs will have a 1:1 relationship with a current registration.

The CAISO is planning to phase in the establishment of business rules which will provide for the capability of a PDR ~~or RDRR~~ Resource ID to have a 1:many relationship with current registrations.

The following process flow illustrates the PDR ~~and RDRR~~ Resource Registration Process Flow including the LSE/UDC review process and its timelines managed by the Demand Response System prior to registration approval and resource ID assignment by the CAISO PDR Coordinator:



12.5.1 Applying for a PDR ~~or RDRR~~ Resource ID using the Demand Response System Registration Process

Demand Response Resource IDs: pre-defined and custom resources

There are two types of Resource ID set ups that can be used in the CAISO Markets for PDR ~~and RDRR~~: those comprised of pre-defined resources and those comprised of custom resources. The use of pre-defined resources allows for quicker assignment of the DRP's

demand response to the PDR ~~or RDRR~~-Resource ID. The use of custom resources requires modifications to the Full Network Model and therefore could have a timeline of up to 12 weeks for a DRP to apply for and receive a custom PDR ~~or RDRR~~-Resource ID for use. The Resource IDs will look similar to this example:

- Pre-defined: PGSA_1_PDRP01, where PGSA represents the location of the demand response by Sub-Lap
- Custom resource: PRMNTE_6_PDRC01

Pre-defined resources use pre-established Generation Distribution Factors (GDFs) to allocate the PDR ~~or RDRR~~-performance (generation) to the associated APNodes of the Sub-Lap. A custom PDR ~~or RDRR~~ will be designed using historic Demand data (provided by the DRP) for the specific network buses to calculate a unique GDF. For both pre-defined and custom PDRs ~~or RDRRs~~, the GDFs will remain static.

PDR Resource ID criteria

All PDR ~~and RDRR~~-Resource IDs will be associated to the end use Loads represented by the DRP based on:

- The physical location, and
- The Load Serving Entity (LSE) of individual end use Loads.

Therefore, prior to applying for a PDR Resource ID(s), the DRP must know which Sub-Lap the end use Loads are in and which LSE (and the LSE's SC) serves the end use Load. This information should be available to the DRP based on the requirement that it must have contractual relationships with the end-use customer, LSE, and UDC. When requesting a PDR ~~or RDRR~~-Resource ID, the DRP should group its end use Loads by both the LSE and Sub-Lap.

Example 1 ~~(applicable for PDR or RDRR)~~: A DRP has 6 End Use Loads and would like to register them to the minimum number of Resource IDs possible. What would be the minimum number of pre-defined Resource IDs that the following locations could be registered to?

Customer	LSE	Sub-Lap	DR Resource ID
1	A	SDG1	PDRP01
2	A	SDG1	PDRP01
3	B	PGF1	PDRP02
4	B	PGF1	PDRP02
5	B	PGSA	PDRP03
6	B	SDG1	PDRP04

Answer to Example 1: Four pre-defined Resource IDs would be the minimum assigned to the DRP because the locations represent 4 different LSE and Sub-Lap combinations.

12.5.2 Applying for a Custom PDR ~~or RDRR~~ Resource ID

If the DRP believes that the pre-defined Resource IDs are not sufficient for its PDR ~~or RDRR~~ needs, the DRP could request a custom Resource ID. The DRP would have to identify the location of the end use customer Loads by bus (which must be in the same Sub-LAP and represented by the same LSE) and provide sufficient historic Load data to demonstrate the appropriate allocation that will be required for the identification of static unique GDFs. This information needs to be provided to the CAISO well in advance of receiving a PDR ~~or RDRR~~ Resource ID. In addition to the internal analysis for the creation of the GDFs, the characteristics of the custom PDR ~~or RDRR~~ must be identified in the Full Network Model and require a modification to it. The Full Network Model is modified approximately every 12 weeks.

Example 2 ~~(applicable for PDR or RDRR)~~: A DRP requests a custom Resource ID for 4 end use Loads that have the same LSE and are located in the same Sub-Lap. Based on historic Load of these 4 end use customers, 80% of the Load is connected to Bus 1 and 20% of the Load is connected to Bus 2. In this example there are two active registrations linked to a single Resource ID. Currently CAISO is only allowing a one to

one relationship between registration and Resource ID. In the future that will change to a one to many relationships. Here is how it will look:

Customer	LSE	Sub-Lap	Location	Registration	GDF	Custom DR Resource ID
1	A	PGF1	Bus 1	Reg 01	0.8	PRMNTE_6_PDRC01
2	A	PGF1	Bus 1	Reg 01		PRMNTE_6_PDRC01
3	A	PGF1	Bus 2	Reg 02	0.2	PRMNTE_6_PDRC01
4	A	PGF1	Bus 2	Reg 02		PRMNTE_6_PDRC01

12.5.2.1 Requesting a Custom Resource ID with Dynamic GDF

If approved by the CAISO to do so, a DRP may submit GDFs as part of its Bid for a given PDR ~~or RDRR~~. In order to be eligible to submit GDFs as part of a Bid, the DRP must request and receive approval from the CAISO to dynamically Bid GDFs. To request a custom GDF, please contact the PDR coordinator at pdrc@caiso.com with the following information: Location of bus, and total MW. The custom GDF can be deployed based on the Master File deployment cycle without the need to wait for the FNM deployment cycle *if only* the GDF's values, not the makeup of the PDR ~~or RDRR~~, are changed from default CAISO values.

12.5.3 Registration Levels

The CAISO will provide the ability to allow changes to the underlying end use Load customers without having to issue a new Resource ID to the DRP. Registration levels were created to allow flexibility for the DRP to revise its end use customers associated with a PDR ~~or RDRR~~, without having to request a new Resource ID. The registration level will also allow easier application of the baseline, as will be explained below. The key aspect of the registration level is that the meter data for both the baseline and the event day will need to be submitted to the CAISO at the registration level of the Resource ID.

The Demand Response System will allow the DRP to create registrations. These registrations must maintain the same standards as the overarching PDR ~~or RDRR~~ with underlying Load represented by the same LSE and located in the same Sub-LAP. ~~Each registration must~~

~~represent participation in the same market(s) and for RDRR have the same Real Time Dispatch Option (Marginal or Discrete) and seasonal term designation.~~ Additional granularity is required for the physical locations of a registration. The location should contain the end use customers that are on the same bus in the Sub-Lap. The Demand Response System uses the term "location" to identify the end use customer data and bus location. In addition, registrations will have defined start and end dates. This will allow for on-going changes to occur at the registration level with limited impact to the effective date of the PDR ~~or RDRR~~ in the Master File. Master File effective dates and PMax will only need to change when the new registration's reduction capacity is less than the current Master File PMax, or the DRP wants to change the current PMax to increase resource capacity. Any Master File update may take 10 Business Days to implement.

Example 3 ~~(applicable for PDR)~~: A DRP has originally 4 customers all with the same LSE and located in the same Sub-LAP and aggregated to one Resource ID (PDRP01). The Resource ID became effective in the CAISO Markets on April 1, 2010. The DRP receives the approvals for adding 2 additional customers to the Resource ID (same LSE and located in the same Sub-Lap) starting July 1, 2010. The DRP will create a second registration as shown below.

Customer	LSE	Sub-Lap	Registration	PDR Resource ID	Registration Start date	Registration End date
1	A	PGF1	Reg 01	PDRP01	04/01/10	06/30/10
2	A	PGF1	Reg 01	PDRP01		
3	A	PGF1	Reg 01	PDRP01		
4	A	PGF1	Reg 01	PDRP01		
1	A	PGF1	Reg 02	PDRP01	07/01/10	12/31/10
2	A	PGF1	Reg 02	PDRP01		
3	A	PGF1	Reg 02	PDRP01		
4	A	PGF1	Reg 02	PDRP01		
5	A	PGF1	Reg 02	PDRP01		
6	A	PGF1	Reg 02	PDRP01		

Note: In this example you see that the PDR Resource ID stayed the same. The Meter Data required for the baseline must represent the registrations and their timeline. So by

07/01/10 ~~(or an event thereafter)~~, the DRP will need to submit to the CAISO the appropriate historic data for Registration 02 so that the baselines can be properly calculated for future event dates after July 1.

~~For RDRR's, the Demand Response System will not allow a DRP to delete registrations during a Reliability Demand Response Services Term (winter/summer) once the registration has been approved. The approved registration and underlying end use Load customers composing the registration must remain in effect and tied to the RDR Resource ID until the end of the Reliability Demand Response Services Term. Therefore, once a registration is created for an RDRR Resource ID the registration and end use Load customer composition will remain the same until the end of the term. However, upon implementation of the 1:many registration functionality and business practice for PDR(s) and RDR(s), additional locations may be added to a RDR Resource ID during a seasonal term by adding a new registration as represented in the following example:~~

~~Example 4: (applicable for RDRR upon implementation of 1:many registration to Resource ID capability): A DRP has originally 4 customers all with the same LSE and located in the same Sub-LAP and aggregated to one Resource ID = PDRP02. The Resource with original registration became effective in the CAISO Markets on April 1, 2012 start of summer season and is participating for the summer Reliability Demand Response Services Term only with a Discrete Real-Time Dispatch option for that term. The DRP receives the approvals for adding 2 additional customers to the Resource ID (same LSE and located in the same Sub-Lap) starting July 1, 2012. The DRP will create a second registration as shown below with additional customers.~~

Customer	LSE	Sub-Lap	Registration	ResID	Term	Discrete	Start date	End date
1	A	PGF1	Reg-01	PDRP02	S	Y	04/01/12 07/01/12	09/30/12
2	A	PGF1	Reg-01	PDRP02	S	Y		
3	A	PGF1	Reg-01	PDRP02	S	Y		
4	A	PGF1	Reg-01	PDRP02	S	Y		
5	A	PGF1	Reg-02	PDRP02	S	Y	07/01/12	09/30/12
6	A	PGF1	Reg-02	PDRP02	S	Y		

7	A	PGF1	Reg-02	PDRP02	S	Y	
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~~Note: In this example, once the functionality that enables 1:many mapping exists then additional locations may be added within a Reliability Demand Response Services Term for a RDRR Resource ID by adding a new registration. This registration is required to have same term end date and dispatch option as the original registration for the RDRR resource ID. The Meter Data required for the baseline must represent all the registrations and their timeline. So by 07/01/12, the DRP will need to submit to the CAISO the appropriate historic data for Reg-02 so that the resource baselines can be properly calculated for future event dates after July 1.~~

12.5.4 Information Required When Applying for a PDR ~~or RDRR~~ Resource ID

During the registration process for obtaining a PDR ~~or RDRR~~ Resource ID, the DRP must provide specific information about the end use Loads involved in the Demand response. This information is needed to allow the LSE, UDC, to review the location information and the CAISO to approve the assignment of the PDR ~~or RDRR~~ Resource ID. This information will be:

- Customer name (required field)
- Service address (required field)
- Service city (required field)
- Sub-LAP location (required field)
- Bus location (suggested for all but required field for Custom Resource only)
- UDC service account number (required)
Note: A location, identified by its UDC service account number, cannot be registered to both a Reliability Demand Response Resource and a Proxy Demand Resource for the same Trading Day.
- LSE (required field)
- LSE's Scheduling Coordinator (suggested for DRP to provide, required field for LSE to verify or provide)

- Profile information -Load type, Load reduction (required field)
- Pseudo location information if applicable (per section 12.5.5)
- For PDR, each registration must have a minimum of 100 KW of load reduction.

~~Additionally, for RDRR the following is applicable:~~

- ~~• Each registration must choose the Reliability Demand Response Services Term for which it will remain active (summer, winter or both).~~
- ~~• Each registration must have a minimum of 500 KW of load reduction.~~
- ~~• Each registration may choose a Discrete Real-Time Dispatch Option and this selection must remain consistent across registrations. Additionally, non-selection defaults RDRR to Marginal Real-Time Dispatch Option which must remain consistent across registrations.~~
- ~~• Once the Discrete Real-Time Dispatch Option is selected, or is not selected defaulting the RDRR to a Marginal Real-Time Dispatch Option, it will remain in effect until the end of that registration's Reliability Demand Response Services Term applicable to the RDRR.~~
- ~~• The maximum Load curtailment for a resource that selects the Discrete Real-Time Dispatch Option shall be no larger than 50 MW.~~
- ~~• Once a RDRR Resource is approved, its registration and end use Load customer composition will remain the same until the end of the Reliability Demand Response Services Term. The DRS will not allow the registration to be deleted, nor will it allow underlying end use Load customers to be added as part of another RDRR or PDR registration until the start of the next Reliability Demand Response Services Term.~~

Once the DRP has completed entering all information appropriately, it must submit the completed registration for approval by the CAISO. As part of the submitted registration review process, both the appropriately DRP designated LSE and UDC will have an opportunity to review the DRP's registration and provide comments if they see any issues with its detail. The LSE and UDC will have 10 business days to review the DRP's registration detail and provide comments as part of this review process. If either the LSE or UDC do not complete their review

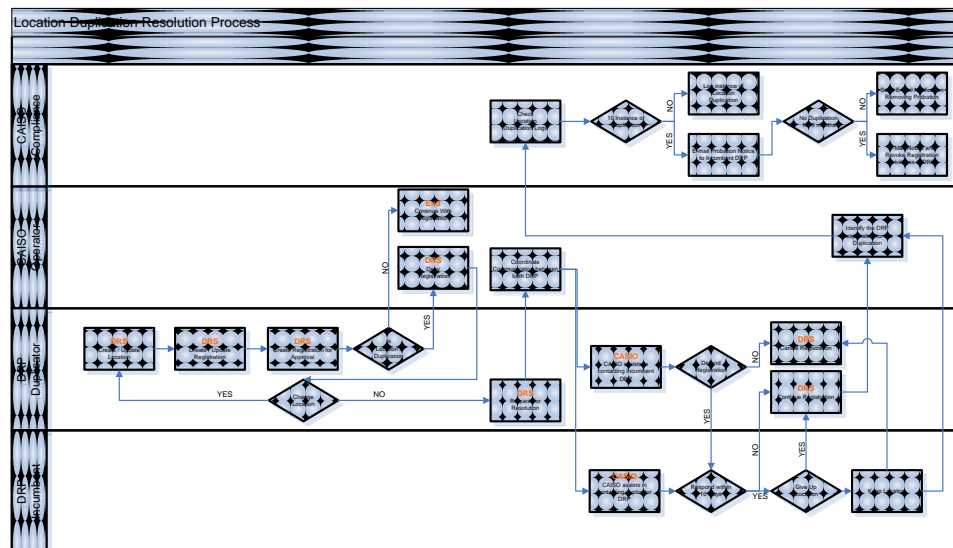
and provide comments within 10 business days, the request will automatically reflect a “Review Complete” status from that entity and move to CAISO for final review and approval.

During the registration review process, if either LSE or UDC identifies registration detail that appears to be in error, they may identify these errors and provide the CAISO with additional information as to how they might be corrected. This information must be provided to the CAISO as comments when signifying a “reviewed complete” status for any registration submitted for their review during their 10 business day review timeframe.

A final registration review is performed by the CAISO of all DRP’s registration detail taking into consideration any comments received as a result of the LSE and UDC review process. If the CAISO determines that there is error in the registration detail that needs to be corrected by the DRP, the registration will be denied as a means to alert the DRP of corrective actions that are being requested by the CAISO. If the CAISO determines the registration detail is complete and accurate, the registration will be locked and the DRP will not be able to modify it. CAISO will send the DRP a partially completed RTD template containing the PDR Resource ID. Upon receipt of the PDR Resource ID from the CAISO, the DRP must submit a resource data template (RDT) following the current RDT process (see RDT process www.caiso.com). This is an established process used to provide the operational characteristics of the PDR so that the Resource ID can be created in the Master File and made valid for market participation. Following the Master File update the registration will be approved and the DRP will be notified that their resource is now active.

In the event that a registration contains location information already included in another active registration, an alert shall be given to the incumbent DRP and PDR coordinator. The PDR coordinator will contact the DRP of record to enable the defense of that location. If the DRP of record is unavailable or takes no action, the existing registered location shall be considered abandoned and made inactive in order to allow the new registration to become active. The time period for the DRP of record’s defense shall be 10 business days.

Additionally, the CAISO has included a compliance procedure that will help to identify those using the Demand Responses System inappropriately. Inappropriate action includes, but is not limited to, the continual submission of Locations that are in use and already designated by another Demand Response Provider. The following provides illustration of the process performed when duplicate locations are attempted to be registered within the DRS.



12.5.5 Option for registration of a Pseudo Location for PDR

A pseudo location is designed to be used as a place holder to assist in managing a resource's rated PMAX. The pseudo location resides only in the Demand Response System (DRS) and is established during the registration process of a **Proxy Demand Resource (PDR)**. The pseudo location may be used as a location capacity buffer in order to establish a PMAX greater than the initial registration of load reduction capacity for a resource. The PMAX registered including the pseudo location buffer, can then be the PMAX that is assigned to that resource ID in the master file. This registration implementation detail is used to sync a resource's predefined PMAX in the CAISO master file to its load reduction capacity in the DRS allowing the master file PMAX to stay constant.

Therefore, a pseudo location provides flexibility in the updating of registrations with the DRS and is designed to reduce the need to process those updates within the CAISO Master File reducing the amount of time necessary to obtain registration change approval.

This is accomplished by:

1. The DRP creates a pseudo location with a maximum load reduction capacity no greater than 2 MW.
2. The DRP submits a registration with all active locations and includes a pseudo location.
3. CAISO sends the DRP a partially completed RDT if it is a new resource as part of the registration process.
4. The DRP Submits a RDT to establish the new PDR in the CAISO master file.

5. If the DRP is adding a pseudo location to an existing PDR a master file update request is submitted to adjust their PMAX to the new value including the pseudo location not to exceed an additional 2MW.
6. CAISO will validate master file PMAX in DRS against requested Master File PMAX taking into account the pseudo location capacity and ensure they are in sync as part of a master file update approval process.
7. Each time a DRP adds location capacity to a previously approved resource, the load reduction capacity of the pseudo location should be adjusted so the total load reduction of the resource remains the same and is no greater than what has been assigned as the master file PMAX for that resource.

Example

DRP currently has 5 MWs of load reduction capability assigned to resource PGST_2_PDRP01. They want to create a 2 MWs buffer so they can manage their portfolio more efficiently.

1. DRP creates a pseudo location for resource PGST_2_PDRP01 with a load reduction capacity of 2 MWs.
2. DRP submits a registration with all their current active location totaling 5 MWs and a new pseudo location set to 2 MWs, with a total load reduction capacity for the registration set to 7 MWs in the DRS.
3. DRP submits a master file update to change PMAX for PGST_2_PDRP01 from 5 MWs to 7 MWs.
4. Master file is updated upon CAISO approval.

A month later the DRP has an additional 1 MW of actual load reduction capability they would like to add to resource PGST_2_PDRP01 registration.

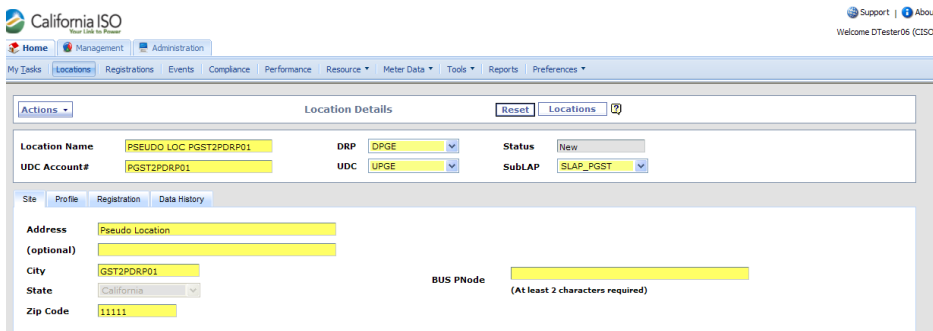
1. The DRP updates the DRS to include an additional customer location with actual load capacity of 1 MW to the PGST_2_PDRP01 resource registration. This location is added to that resources registration in the DRS.
2. As part of the registration update for PGST_2_PDRP01, the pseudo location load reduction capacity is reset to 1 MW to reflect the additional customer location capacity and maintain the total load reduction capacity and PMAX of 7 MWs for that resource (ie actual location capacity + pseudo location capacity = registered resource PMAX).
3. CAISO receives registration, and confirms that master file PMAX is still the same as the DRS PMAX and approves registration.
4. DRP's SC submits meter data to reflect the changes to the new registration

Creating a Pseudo Location in the DRS

When registering a pseudo location a DRP should:

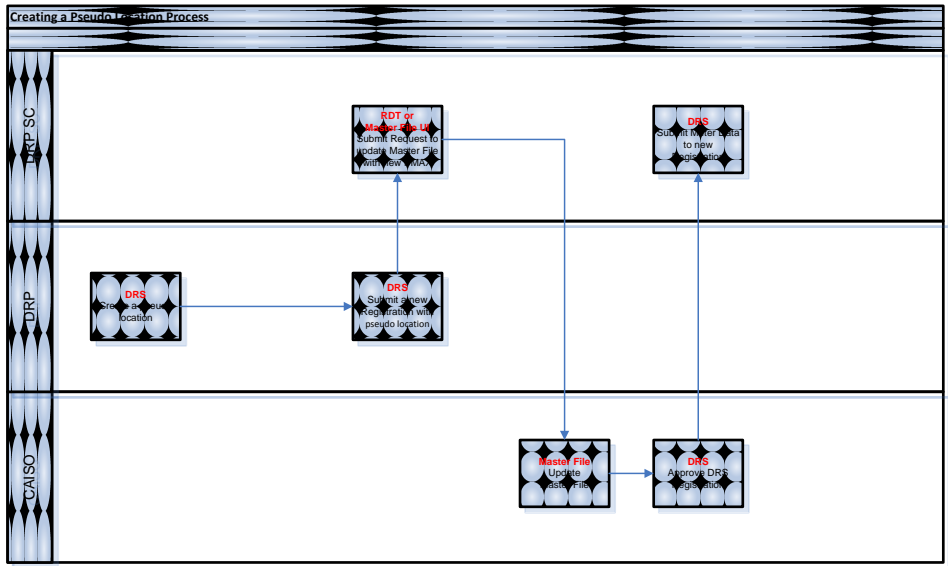
- Create a location name that begins with the prefix "PSEUDO LOC", the DRP may add anything after "PSEUDO LOC". This will identify the location as a pseudo location.

- Create a unique UDC account number and assign it to the pseudo location to identify it from all other locations and to ensure that the same UDC account number would not be used to identify any other registered location in order to avoid location duplication. It is suggested that the UDC account number for any pseudo location begin with the ID of DRP registering that location followed by a unique combination of letters and numbers not to exceed a maximum of 20 characters. Example: DPGE001psuedo
- Ensure that there is only one pseudo location registered per resource.

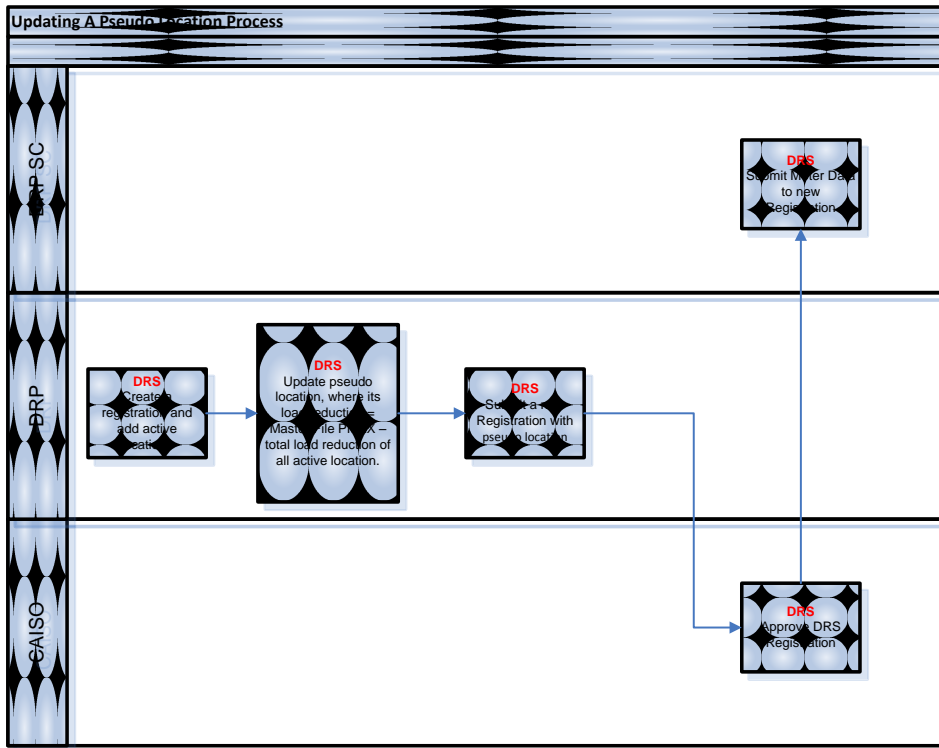


Process Flow

The following process flow detail how a DRP would create a pseudo location and submit it to the CAISO as part of a registration and initial PDR setup.



The following process flow details how a DRP could use a pseudo location to manage the dynamic nature of their PDR location portfolio without having to go through the Master File update process.



Pseudo Location Meter Data requirements

There is no meter data associated with a pseudo location; meter data submissions should reflect only non pseudo locations in a registration.

12.6 Using the Demand Response System for PDR ~~and RDRR~~ Meter Data Submission, Customer Baseline, and Demand Response Energy Measurements

Meter Data Submission

A PDR ~~and RDRR~~ is a Scheduling Coordinator Metered Entity. Therefore, the SC representing the PDR ~~or RDRR~~ must have a Meter Service Agreement for Scheduling Coordinators (MSA

SC) in place supporting its ability to submit Settlement Quality Meter Data (SQMD) to the CAISO. During the time of registration of the PDR ~~or RDRR~~, access to the Demand Response System (DRS) will be granted based on the information provided in the User Application Access Request Form.

Access will include set up for the SC to have the ability to submit SQMD ~~or Estimated SQMD~~ (for calculation of ~~initial Recalculation~~ settlement statements only per CAISO Tariff ~~Section 10.3.6.1~~) into the DRS for the registered PDRs ~~or RDRRs~~ it represents. Upon successful completion of the registration process and prior to active participation in the CAISO Markets (ie. awarded bids or schedules for provision of Ancillary Services, Energy or have been dispatched in Real Time), forty-five (45) calendar days of historical Meter Data will need to be submitted for establishment of the PDR's baseline. ~~A RDRR that provides Demand Response Services only in Real Time shall submit Meter Data for the RDRR for those trade dates on which the Demand Response Services were provided and for the forty-five (45) calendar days preceding the Trade Day for which the Demand Response Services were provided in order to establish the RDRR's baseline (per CAISO Tariff Section 10.3.6.4).~~ Meter Data submission will follow the "DRS Technical Interface Specifications" process located under the metering section of the CAISO Website and follow timelines set forth in CAISO Tariff Section 10 and the CAISO published settlement calendar.

Upon receipt of a PDR ~~or RDRR~~-Resource ID and its approval by the CAISO in the DRS, forty-five (45) calendar days of historical Meter Data can be submitted at one time into the DRS as part of the registration process or may be submitted at a later time. Baseline and Event Day Meter Data is required for the PDR ~~or RDRR~~ in order to calculate a Demand Response Energy Measurement for an event. If either Event Day or historical baseline Meter Data is absent, the PDR ~~or RDRR~~ will have no Demand Response Energy Measurement calculated for Settlement.

SQMD must be submitted to the DRS for the PDR ~~or RDRR~~ as Load to the effective registration assigned in the DRS. Submittal of SQMD is required for all underlying Load at the registration level for the PDR ~~or RDRR~~-Resource ID. The key aspect of the registration level is that the SQMD for both the baseline and the event day will need to be submitted to the CAISO at the effective registration level for the PDR ~~or RDRR~~-Resource ID.

SQMD must be submitted for those trade dates which the PDR has received an award for Non-Spinning Reserve, Energy or has been dispatched in Real Time. ~~SQMD must be submitted for those trade dates which the RDRR has received an award for Energy or been dispatched in Real Time.~~ Meter Data Submittal timelines must be followed pursuant to section 10.3.6 of the CAISO Tariff. Submittal of SQMD on a daily basis during those seasons in which the PDR ~~or RDRR~~ is actively bidding into the CAISO markets, to ensure that both Event Day and historical

baseline Meter Data is available in the DRS for trade dates that bids are awarded, is suggested as a best practice for PDR's ~~and RDRR's~~, however, is not a requirement.

The CAISO shall calculate, account for and settle all charges and payments for Initial Settlement Statement T+3B using CAISO estimates for all load and generation including PDRs ~~and RDRRs~~. Therefore, no meter data can be submitted for the Initial Settlement Statement T+3B calculation and Demand Response Energy Measurement for the PDR ~~or RDRR~~ will be based on their Expected Energy and dispatch of that resource as calculated in the Real-Time Market and as modified by any applicable corrections to the Dispatch Operating Point for the resource pursuant to CAISO Tariff Section 11.1.4.

If there is no SQMD submitted into the DRS by the T+8B Meter Data submittal deadline, the CAISO will continue to use the PDR ~~or RDRR~~ CAISO meter data estimations for the Recalculation Settlement Statement T+12B calculation.

If there is no SQMD submitted into the DRS by T+48B Meter Data submittal deadline for the recalculation settlement statement, the CAISO will not estimate Meter Data for the underlying Load of the PDR; the CAISO will be unable to create a baseline, nor will it calculate a Demand Response Energy Measurement without available SC submitted SQMD, even if it was an event day. ~~However, in accordance with CAISO Tariff Section 10.3.6.2, failure to submit Settlement Quality Meter Data by T+48B will be considered late and subject to sanctions pursuant to CAISO Tariff Section 37.5.~~ In addition, CAISO estimated Meter Data will no longer be used in the subsequent recalculation settlement statement.

Format for Meter Data submissions

Settlement Quality Meter Data submittal requires the following

- Meter Data submittal for PDR ~~or RDRR~~ registrations selecting the CAISO 10 in 10 non event day selection baseline methodology must be as Load.
- Meter Data submittal for PDR ~~or RDRR~~ registrations selecting a CAISO approved statistically derived baseline methodology must be as Generation.
- Hourly intervals for twenty-four hours for Day-Ahead only PDR ~~or RDRR~~.
- Five (5) minutes interval for twenty-four hours if resource is participating in Ancillary Services (AS) or Real-Time Markets.

- Meter Data submittals must include all twenty-four hours for any given trade date. Partial, incomplete, or gaps in data will result in the inability of the DRS to calculate a baseline and/or Demand Response Energy Measurement.
- Five minute Meter Data can be created by parsing 15-minute recorded Meter Data into three equal 5-minute intervals.
- All data must be submitted in XML Format

The XML format details are listed on “Technical Interface Specification for DRS Exchange Services” located on www.caiso.com.

Listed below is a table of the XML file schema for submitting the load and generation information to the DRS with additional file submission requirements.

Element	Data Description	Req'd	Type
MessageHeader			
/TimeDate	The dateTime, in GMT, when the payload is published.	Yes	dateTime
/Source	The source of published data. The value for this payload is CAISO.	No	string
MessagePayload/MeterDataContainer/RegisteredGenerator			
/mrid	Resource id for the PDR	Yes	string
/MeterData/Registration/mrid	Registration id for given PDR	Yes	string
/MeterData/MeterData/Unit	Unit Of Measure for meter data. Valid values for initial DRS release are: KWH	Yes	string
/MeterData/MeterData/MeterData/MeasurementType	Measurement type for meter data. Valid values for initial DRS release are: GEN, LOAD.	Yes	string
/MeterData/MeterData/Measurement/IntervalLength	Interval length for meter data. Valid values for initial DRS release are: 5, 60	Yes	int
/MeterData/MeterData/Measurement/MeasurementValue/IntervalEndTime	Interval end time	Yes	dateTime
/MeterData/MeterData/Measurement/MeasurementValue/meterValue	Meter value	Yes	double

12.6.1 Customer Baseline

A Customer Baseline will be calculated by the DRS as a value or values based on historical Load meter data in order to measure the delivery of Demand Response Services. The Customer Baseline establishes a method for setting a customer's baseline load, an estimate of how much electricity a customer would have used had it not reduced its use in response to Day-Ahead and Real-Time prices. The Customer Baseline of a PDR is compared against its actual Load for a Demand response event in order to calculate the PDR Energy Measurement.

The following section specifies the methodology employed to calculate the Customer Baseline for determination of a PDR's ~~or RDRR's~~ performance.

12.6.1.1 Customer Baseline Methodology

- 10 in 10 non event day selection method (an average of the load in the last 10 eligible days)

12.6.1.2 Customer Baseline Window

- The Customer Baseline window for Meter Data will be 45 calendar days from which the 10 most recent eligible days will be selected.
- The selection of Customer Baseline data will include a number of the most recent days, excluding different day-types and previous events days (definitions below)
- Two different day-types will be supported:
 - Weekday (Monday through Friday)
 - Weekend/Holiday (Saturday, Sunday, or any NERC holiday)

A previous event day is a day on which there was either a PDR event, ~~RDRR event~~ or an Outage recorded in SLIC. Previous event days are specific to the PDR ~~or RDRR~~. The following table specifies under which conditions a PDR ~~or RDRR~~ is consider to have an "event day".

Market Participation	status	event day
Day-Ahead Schedule	yes	yes
Real Time Energy Dispatch	yes	yes
AS Capacity Award only (not applicable for RDRR)	yes	no
AS Energy Dispatch (not applicable for RDRR)	yes	yes
RUC Capacity Award only (not applicable for RDRR)	yes	no
Outage	yes	yes
Non- CAISO Reliability Dispatch (applicable only for RDRR)	yes	yes

- The selection of Customer Baseline days is performed by iterating backward through the acceptable days prior to the event day.
- Once the target number of days is reached, selection ends.
- If the target number of days is not reached, but the minimum number of days is reached, the Customer Baseline is calculated on the selected days (see below).
- If the minimum number of days is not reached, the highest usage prior event days within the Customer Baseline window will be used to reach the minimum number of days. The highest usage event days are defined as the highest totalized load for the resource during event hours.
- Target & minimums are defined as:

	Weekday	Weekend/Holiday
Target	10	4
Minimum	5	4

- There is no elimination for “abnormally low” or “abnormally high” usage days.
- The Customer Baseline shall be calculated as a simple hourly average of the selected days’ Meter Data. (*Note: five-minute Meter Data received for the selected days will be converted to hourly data for the purposes of calculating the Customer Baseline, as calculation is based on the average MWh consumption for each hour of the event period across all the selected days.*)
- The Customer Baseline will be calculated at the registration level to facilitate versioning of the underlying customers in a registration.

12.6.1.3 Load Point Adjustment

- The Customer Baseline calculation will include a symmetric multiplicative adjustment, *morning adjustment*, unless otherwise requested by the DRP and approved by the CAISO.
- The multiplier will be calculated by averaging at the 4 hours prior to the event, excluding the hour immediately prior to the event start and defined as the ratio of the average load for these 3 hours relative to the same 3 hour average of the Customer Baseline calculation data set. The same multiplier will be applied to each hour of the event.
- The multiplier will be capped at both a 20% increase (load ratio = 1.2) and a 20% decrease (load ratio = 0.8).

The following provide various Load Point Adjustment examples:

Example 7: Event Day/Hour: August 15, 2010 – HE 16

Load	PDR Meter	Raw Baseline
HE12	11	14
HE13	10.2	14.2
HE14	12.5	15.5
Average	11.23	14.57

Load Point Adjustment Ratio = ~~PDR or PDRR~~ Meter/Raw Baseline= 11.23 / 14.57

= .7707 or 77.07%

= 80%

Load Point Adjustment uses a floor of 80% as multiplier against raw Customer Baseline to establish adjusted Customer Baseline

Example 8: Event Day/Hour: November 15, 2011 – HE 16

Load	Meter	Raw Baseline
HE12	18	15
HE13	19.2	15.2
HE14	20.75	16.5
Average	19.32	15.57

$$\text{Load Point Adjustment} = \text{Meter/Raw Baseline}$$

$$= 19.32 / 15.57$$

$$= 1.24 \text{ or } 124\%$$

= 120% Load Point Adjustment uses a ceiling of 120% as multiplier against raw Customer Baseline to establish adjusted Customer Baseline

Example 9: Event Day/Hour: August 15, 2011 – HE 12, 13, and HE18

Load	Meter	Raw Baseline
HE08	16	15
HE09	16.5	15.2
HE10	17.5	16.5
Average	16.67	15.57

$$\text{Load Point Adjustment} = \text{Meter/Raw Baseline}$$

$$= 16.67 / 15.57$$

$$= 1.07 \text{ or } 107\%$$

A Load Point Adjustment of 107% will be applied as multiplier against raw Customer Baseline to establish adjusted Customer Baseline for HE12 and 13.

Load	Meter	Raw Baseline
HE14	16	17.13
HE15	16.5	17.25
HE16	17.5	17.67
Average	16.67	17.35

Load Point Adjustment = Meter/Raw Baseline

$$= 16.67 / 17.35$$

$$= .96 \text{ or } 96\%$$

A Load Point Adjustment of 96% will be applied as multiplier against raw Customer Baseline to establish adjusted Customer Baseline for HE18.

12.6.2 Customer Baseline and Demand Response Energy Measurements – Demand Response System Calculations

The following details the calculation of raw and adjusted baselines and the Energy measurements used in the settlement of PDR ~~or RDRR~~:

Baseline Variables	
r	= registration
e	= event day
d	= historical basis day (days used for the baseline)
h	= hour (hours of the defined event)
m	= 5 minute interval (0,5,10...55)
x	= discrete AS dispatch event for a PDR
n	= number of 5 minute intervals in the specific AS dispatch event
Adjustment Variables	
s	= adjustment window size (always 3)
t	= adjustment window offset (always 2)
i	= adjustment window start hour (for the defined method, this is always $\min(h) - 4$)
j	= adjustment window end hour (for the defined method, this is always $\min(h) - 2$)

12.6.2.1 Baseline

A raw baseline for the registration (r) for a given PDR ~~or RDRR~~ for the event day for each event hour using the historical basis days identified through the iterative process is calculated first:

$$\text{Raw Baseline}_{\text{reh}} = (1 / (\text{count} (d)) * \sum_d \text{Load}_{\text{rdh}}$$

Where Load is the SQMD submitted for underlying Load at the registration level for the PDR ~~or RDRR~~-Resource ID.

Next the adjustment ratio is calculated which will be used for this registration for the entire event day based on the first event hour of the day. Note that **h** (the event hours) are those for the entire PDR ~~or RDRR~~, and are thus the same for all underlying registrations that are effective on the event day.

$$i = \min(h) - s - t + 1$$

$$j = \min(h) - t$$

If ($i < 1$)

- o then $\text{Adjustment}_{\text{re}} = 1$
- o else $\text{Adjustment}_{\text{re}} = \max(0.8 , \min(1.2 , \sum_{h=i..j} \text{Load}_{\text{rdh}} / \sum_{h=i..j} \text{RawBaseline}_{\text{rdh}}))$

Finally, the final adjusted baseline for the registration for the event day for each event hour is calculated.

$$\text{Baseline}_{\text{reh}} = \text{Adjustment}_{\text{re}} * \text{Raw Baseline}_{\text{reh}} (1 / (\text{count} (d)) * \sum_d \text{Load}_{\text{rdh}}$$

See Attachment G for PDR/~~RDRR~~ Post Market Activity Example

12.6.2.2 ~~Demand Response~~PDR Energy Measurements

Each registration will have its own generation curve, calculated as the difference between that registration's baseline and the Load for the registration for each event hour.

$$\text{Energy}_{\text{reh}} = \text{Baseline}_{\text{reh}} - \text{Load}_{\text{reh}}$$

The PDR ~~or RDRR~~ totals will be based on the underlying registrations that are effective on the event day.

$$\text{PDRLoad}_{\text{eh}} = \sum_r \text{Load}_{\text{reh}}$$

$$\text{PDRBaseline}_{\text{eh}} = \sum_r \text{Baseline}_{\text{reh}}$$

$$\text{PDREnergy}_{\text{eh}} = \sum_r \text{Energy}_{\text{reh}}$$

Note, PDREnergy = max (0, PDREnergy)

~~Demand Response~~PDR Energy Measurement Adjustment for Real Time

For those time periods when a PDR ~~or RDRR~~ was RT dispatched during the event hour AND 5-minute load data has been supplied for all underlying registrations for all whole event hours, the following Real-Time adjustment will be made to the ~~Demand Response~~PDR Energy Measurement in order to simulate a Real-Time Energy curve. SQMD in Settlement Intervals of five (5) minutes must be submitted for all whole hours in which a PDR ~~or RDRR~~ is awarded Ancillary Services (AS) and/or dispatched for RT Imbalance Energy.

$$\text{PDREnergy}_{\text{em}} = 1/12 * \text{PDRBaseline}_{\text{reh}} - \sum_r \text{Load}_{\text{rem}} \text{ (for each m in h)}$$

Note, PDREnergy_{em} = max (0, PDREnergy_{em}) for each m in h

The Real-Time adjustment calculates a Demand-ResponsePDR Energy Measurement for each 5-minute interval by subtracting the 5 minute interval load from the pro-rated hourly baseline.

Example 9: Example of Real-Time UIE adjustment for a resource in Interval 15.

Hourly

Interval	Load	Baseline	Reduction	PDR EM
13	720	1080	360	360
14	720	1080	360	360
15	720	1080	360	360
16	720	1080	360	360

5-Minute - Raw Decomposition

Interval	Load	Baseline	Reduction	PDR EM
15:00	60	90	30	30
15:05	60	90	30	30
15:10	60	90	30	30
15:15	60	90	30	30
15:20	60	90	30	30
15:25	60	90	30	30
15:30	60	90	30	30
15:35	60	90	30	30
15:40	60	90	30	30
15:45	60	90	30	30
15:50	60	90	30	30
15:55	60	90	30	30
Sum	720	1080	360	360
Avg	60	90	30	30

5-Minute - UIE Adjusted

Interval	Load	Baseline	Reduction	PDR EM	DLA
15:00	90	90	0	0	0
15:05	75	90	15	15	15
15:10	60	90	30	30	30
15:15	55	90	35	35	35
15:20	55	90	35	35	35
15:25	60	90	30	30	30
15:30	55	90	35	35	35
15:35	50	90	40	40	40
15:40	55	90	35	35	35
15:45	60	90	30	30	30
15:50	55	90	35	35	35
15:55	50	90	40	40	40
Sum	720	1080	360	360	360
Avg	60	90	30	30	30

5-Minute - UIE Adjusted

Demand-ResponsePDR Energy Measurement and the Default Load Adjustment (DLA) will be calculated and presented in the UI (user -interface) at the 5' granularity with the UIE adjustment.

Example 10: Example noting that even if Hourly Performance > 0, there may be 5' interval < 0 which will be set = 0

Hourly

Interval	Load	Baseline	Reduction	PDR EM
13	1020	1080	60	60
14	1020	1080	60	60
15	1020	1080	60	60
16	1020	1080	60	60

5-Minute - Raw Decomposition

Interval	Load	Baseline	Reduction	PDR EM
15:00	85	90	5	5
15:05	85	90	5	5
15:10	85	90	5	5
15:15	85	90	5	5
15:20	85	90	5	5
15:25	85	90	5	5
15:30	85	90	5	5
15:35	85	90	5	5
15:40	85	90	5	5
15:45	85	90	5	5
15:50	85	90	5	5
15:55	85	90	5	5
Sum	1020	1080	60	60
Avg	85	90	5	5

5-Minute - UIE Adjusted

Interval	Load	Baseline	Reduction	PDR EM
15:00	85	90	5	5
15:05	85	90	5	5
15:10	80	90	10	10
15:15	75	90	15	15
15:20	80	90	10	10
15:25	85	90	5	5
15:30	90	90	0	0
15:35	95	90	-5	0
15:40	95	90	-5	0
15:45	90	90	0	0
15:50	85	90	5	5
15:55	75	90	15	15
Sum	1020	1080	60	70
Avg	85	90	5	5.83333333

5-Minute - UIE Adjusted

DLA
5
5
10
15
10
5
0
0
0
0
5
15
70

As noted, in this example hourly performance is positive but small, and thus 5' performance is varied. All 5' performance intervals with negative energy measurement will be set = 0 as part of the UIE adjustment calculation logic. Both Demand Response PDR Energy Measurement and the Default Load Adjustment (DLA) will be calculated and presented in the UI (user -interface) at the 5' granularity with this UIE adjustment logic.

12.6.2.3 Default Load Adjustment

A Default Load Adjustment will be used to adjust the UIE Settlement of the LSE for the measured Energy of all PDRs ~~or RDRRs~~ associated with the LSE's SC within a particular DLAP. The Default Load Adjustment will also be based on the underlying registrations that are effective on the event day within a given DLAP Load Resource ID.

$$DLA_{DLAPResourceID} = \sum PDREnergy_{DLAPResourceID}$$

The ~~Demand Response~~PDR Energy Measurement will be provided as a Generation quantity and the Default Load Adjustment data will be provided as a load quantity.

$$PDREnergy_{em} = 1/12 * PDREnergy_{reh} \text{ (for each m in h)}$$

$$DLALoad_{em} = 1/12 * DLAEnergy_{reh} \text{ (for each m in h)}$$

If a DRP's SC fails to submit SQMD for a PDR ~~or RDRR~~ then the CAISO will be unable to create a baseline or calculate the ~~Demand Response~~PDR Energy Measurement for the resource even if it was an event day for that resource. Therefore, there would be no default load adjustment associated with the PDR ~~or RDRR~~ and there will be no adjustment made to the Meter Data of the resources LSE's SC Default Lap resource ID for that particular PDR ~~or RDRR~~ which would have an impact to the UIE Settlement of the LSE in which the PDR ~~or RDRR~~ resided.

Additionally, the CAISO is indifferent to the treatment of Estimated Settlement Quality Meter Data and Actual Settlement Quality Meter Data submitted by the LSE's SC for the DLAP Resource ID in which a PDR ~~or RDRR~~ may be associated. The CAISO will create a Default Load Adjustment and apply it to either the ESQMD or SQMD submitted. The Default Load Adjustment will also be applied to CAISO Estimated Settlement Quality Meter Data if applicable, in the event that no meter data is submitted by the LSE's SC for the DLAP Resource ID by ~~T+5B-8B~~ (see CAISO Tariff Section 10.3.6.42). The Default Load Adjustment will not be calculated, estimated, nor will it be applied for the Initial Settlement Statement Calculation or for any Recalculation Settlement Statement ~~T+12B~~ Calculation for those PDRs ~~or RDRs~~ for which CAISO Estimated Meter Data is calculated.

12.7 PDR No Pay Dispatch Performance (meter before/after in 5 minute intervals)

A PDR that is dispatched for Energy from Ancillary Service capacity must show a reduction in the underlying load equal to the amount of the Dispatch within 10 minutes, as well as sustain the response for the duration of the Dispatch. In contrast, the baseline methodology for Instructed Imbalance Energy Settlement measures response relative to typical usage. Therefore, the CAISO will use a “meter before/ meter after” approach for the Undelivered category of No Pay for Spinning and Non-Spinning Reserve, even though the settlement of Instructed Imbalance Energy will use the PDR Energy Measurement method. The meter before/after amount calculated by the Demand Response System is called PDR No Pay Dispatch Performance.

Note: SQMD in Settlement Intervals of five (5) minutes must be submitted for all 24 hours for a trade date in which a PDR is awarded Ancillary Services (AS) or has been dispatched for AS and/or RT Imbalance Energy.

First, PDR_Load total for the unique PDR AS dispatch event x is calculated. Unique PDR AS dispatch events are defined as each contiguous time period where the PDR Non-Spin IIE > 0. Note that m=0 represents the interval immediately prior to the event, with 1 to n as the subsequent 5 minute intervals. For an AS dispatch event that extends across operating hours, an adjustment to the PDR No Pay Dispatch Performance is made based on the baseline calculated in Section 12.6.2.1. This baseline adjustment ensures that the load curtailment offered as an ancillary service is not a normal hourly load variation.

$PDRLoad_{exm} = \sum_r Demand_{rem}$ (for each registration for m=0..n that is within x)

Hourly Baseline Adjustment_{reh=i} = Baseline_{reh=0} - Baseline_{reh=i}

Where h = 0 is the hour where the AS dispatch event begins and h = i is each consecutive hour in which the AS dispatch event continues.

Finally, calculate the performance for each interval after the event start.

$PDRNoPayDispatchPerformance_{exm} = \max(0, -1/12 * (\text{Hourly Baseline Adjustment}_{reh=i})) +$

$(PDRLoad_{exm=0} - PDRLoad_{exm})$ (for each m=1..n)

Five-minute PDR No Pay Dispatch Performance values calculated by the Demand Response System will be submitted to the settlement system as a Generation quantity. Five-minute PDR No Pay Dispatch Performance values will be summed to the ten-minute Settlement Interval to determine compliance with Dispatch Instructions. The No Pay methodology for Ancillary Service compliance is described in the *BPM for Settlements and Billing*.

12.8 PDR ~~or RDRR~~ Hourly Generation – Alternative Baseline for Demand Response PDR Energy Measurement

A Demand Response Provider representing a PDR ~~or RDRR~~ may submit a written application to the CAISO for approval of a methodology for deriving Settlement Quality Meter Data, referred to in this BPM as Generation Data, for the ~~RDRR or~~ PDR that consists of a statistical sampling of Energy usage data. (~~CAISO Tariff Section 10.1.7~~)

12.9 DRS Monitoring Process

The CAISO will monitor through the DRS and business processes the performance of the PDR ~~or RDRR~~. In general, the CAISO will look at certain metrics across all PDRs ~~or RDRRs~~ and flag those which fall outside typical ranges. However, based on monitoring results, the CAISO will seek actions as outlined in CAISO Tariff Section 30.6.3.

12.10 Outages

PDR ~~and RDRR~~ resources are allowed to have outages, but will be limited to updates to a resources ramp rates, or modifying the capacity to 0. PDR ~~and RDRR~~ resources are an all or nothing resource, which limits how much a resource can be derated. They are also prevented from submitting a derated of their PMin. SLIC has been updated to enforce these business rules.

SLIC has been updated to permit a PDR ~~or RDRR~~ resource to submit only PMax derates or Ramp Rate derates. Any other data entered in SLIC through either the UI or API for a PDR Resource ID shall return an error message. It also has validation to restrict PMax derates entries for PDR Resource IDs to be only 0 MW. A PMax derate is used to indicate a day should not be used in the baseline calculation. Since a day is either valid or invalid, no partial derates are permitted. Any PMax value other than 0 MW entered in SLIC through either the UI or API for a PDR Resource ID shall return an error message.

-
- When submitting outages, Scheduling Coordinators must only use one or both cause codes designated for PDR ~~or RDRP~~ resources. 10100 – anomalous days for baseline calculations
 - 10101- Unavailability of awarded AS capacity

In order to keep a Resource ID active and reduce the need to make updates to the CAISO Master File, the DRP using their scheduling coordinator can submit extended outages to derate their resource to 0 MW when they do not wish to participate in the market.

Attachment A

END USE METER STANDARDS

Attachment A: End Use Meter Standards

All metering is of a revenue class metering accuracy in accordance with the ANSI C12 standards on metering and any other requirements of the relevant UDC or Local Regulatory Authority that apply. Such requirements apply to meters, current transformers, potential transformers, and associated equipment. ANSI C12 metering standards include the following:

- ANSI C12.1 – American National Standard Code For Electricity Metering
- ANSI C12.6 – American National Standard For Marking And Arrangement Of Terminals For Phase-Shifting Devices Used In Metering
- ANSI C12.7 – American National Standard For Watt-hour Meter Sockets
- ANSI C12.8 – American National Standard For Test Blocks And Cabinets For installation Of Self-Contained A-Base Watt-hour Meters
- ANSI C12.9 – American National Standard For Test Switches For Transformer-Rated Meters
- ANSI C12.10 – American National Standard For Electromechanical Watt-hour Meters
- ANSI C12.11 – American National Standard For Instrument Transformers For Revenue Metering, 10 kV BIL Through 350 kV BIL
- ANSI C12.16 – American National Standard For Solid-State Electricity Meters
- ANSI C12.18 – American National Standard For Protocol Specification For ANSI Type 2 Optical Port
- ANSI C12.20 – American National Standard For Electricity Meters 0.2 and 0.5 Accuracy Class
- ANSI C57.13 – IEEE Standard Requirements for Instrument Transformers

Attachment B

TECHNICAL SPECIFICATIONS

Attachment B: Technical Specifications

Section A. Meter Configuration Criteria

A1 Power Flow Conventions

Meters must be installed and configured in such a manner so as to define the 4 Quadrants referred to in Exhibit B-1.

A2 CAISO Standard Meter Memory Channel Assignments

Metering Facilities must be installed and configured in such a manner so as to comply with the following CAISO requirements:

- Channel 1 must record active power (kWh) delivered by the CAISO Controlled Grid;
- Channel 2 must record reactive power (kVARh) delivered by the CAISO Controlled Grid;
- Channel 3 must record reactive power (kVARh) received by the CAISO Controlled Grid;
- Channel 4 must record active power (kWh) received by the CAISO Controlled Grid

For metering with bi-directional power flows, CAISO reserves the right to require metering that measure and report 4 quadrant VARs. Situations like a generating plant that nets gross generator output and auxiliary loads on one meter, which could swap from a supplying to a buying mode and vice versa may require this type of metering. To properly account for such cases, six channels of data are required. This configuration is considered optional unless specified by CAISO as required. Such Metering Facilities must be installed and configured in such a manner so as to comply with the following CAISO requirements:

- Channel 1 must record active power (kWh) delivered by the CAISO Controlled Grid;
- Channel 2 must record quadrant 1 reactive power (kVARh) delivered by the CAISO Controlled Grid;
- Channel 3 must record quadrant 3 reactive power (kVARh) received by the CAISO Controlled Grid;
- Channel 4 must record active power (kWh) received by the CAISO Controlled Grid;
- Channel 5 must record quadrant 2 reactive power (kVARh) delivered by the CAISO Controlled Grid;

- Channel 6 must record quadrant 4 reactive power (kVARh) received by the CAISO Controlled Grid.

A3 CAISO Standard Meter Display Modes

The following display readings must be displayed in the normal display mode to comply with CAISO requirements.

Normal Display Mode (Standard Configuration, Uni-directional/Bi-directional kWh and kVARh)

For standard metering applications the display items should be utilized in the sequence listed below. When metering uni-directional power flows, the quantities listed below that do not apply (i.e. for generation only applications, the delivered quantities should have zero accumulation) may be omitted. The only exception to this is where the display items correlate to the load profile channel assignments. The 4 display readings that correlate to the 4 load profile channels must also be displayed.

Exhibit A-1 – Normal Display Mode (Standard Configuration)

1	Device ID
2	Date/Time MM:DD:YYHH:MM:SS (Standard Time ⁹ , military format)
3	Total kWh delivered by the CAISO Controlled Grid
4	Maximum kW (5 minute or hourly demand interval) delivered by the CAISO Controlled Grid
5	Date and time of maximum kW delivered by the CAISO Controlled Grid
6	Total kVARh delivered by the CAISO Controlled Grid
7	Total kVARh received by the CAISO Controlled Grid
8	Total kWh received by the CAISO Controlled Grid
9	Maximum kW (5 minute or hourly demand interval) received by the CAISO Controlled Grid
10	Date and time of maximum kW received by the CAISO Controlled Grid

Normal Display Mode (Optional Configuration, Bi-directional kWh and Four Quadrant kVARh)

⁹ Meter may not shift to Day-Light Savings Time

For metering bi-directional power flows in which CAISO requires optional 4 quadrant VAR measurement, the following display items should be displayed in the sequence listed below:

Exhibit A-2 Normal Display Mode (Optional Configuration)

1	Device ID
2	Date/TimeMM:DD:YY:HH:MM:SS (Standard time, military format)
3	Total kWh delivered by the CAISO Controlled Grid
4	Maximum kW (5 minute or hourly demand interval) delivered by the CAISO Controlled grid
5	Date and time of maximum kW delivered by the CAISO Controlled Grid
6	Total kVARh for Quadrant 1
7	Total kVARh for Quadrant 2
8	Total kVARh for Quadrant 3
9	Total kVARh for Quadrant 4
10	Total kWh received by the CAISO Controlled Grid
11	Maximum kW (5 minute or hourly demand interval) received by the CAISO Controlled Grid
12	Date and time of maximum kW received by the CAISO Controlled Grid

Consumption Values

The consumption values must be in XXXXX.X format and demand in XXXX.XX format. The register-scaling factor should be set such that the display does not roll over in less than 60 days.

A3.1 Alternate Display Mode

The values listed below should be displayed in the alternate display mode to comply with CAISO requirements:

- Instantaneous kW delivered and received by the CAISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is received by the CAISO Controlled Grid)
- Phase A, B and C voltage magnitude and phase angle

- Phase A,B and C current magnitude and phase angle
- Neutral current magnitude and phase angle (if available)

When available, the alternative display mode may also be used by CAISO Metered Entities to display other definable quantities in sequence after the values defined above.

A3.2 Test Mode Display

The following values should be displayed in the test mode to comply with CAISO requirements:

- Total pulse count or energy measured for test; and
- Total consumption during test.

During the test mode the above values should be provided for each function being tested (Watts, VARs). The data displayed by the meter while in test mode must not change the normal mode display registers and should not be recorded in the load profile channels. This requirement is imposed to prevent the test data from being recorded as actual load/generation data. CAISO Metered Entities can add additional display quantities in sequence in the values defined above.

A4 Transformer and Line Loss Correction Factor

CAISO Metered Entities are responsible for properly calculating and applying the Transformer and Line Loss Correction Factor to the meter to reflect point of delivery to the CAISO Controlled Grid.

A5 Distribution Compensation Factor (DCF)

If applicable per BPM section 5.1.1, CAISO Metered Entities are responsible for obtaining an agreed upon distribution compensation factor from the appropriate UDC/Distribution Company/interconnection entity and applying it to the meter to reflect losses or credits attributed across a Distribution System to the point of delivery to the CAISO Controlled Grid.

A6 CT/VT and Cable Loss Correction Factors

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet the minimum CAISO accuracy requirements, then one of the actions listed below must be taken:

-
- a. Replace the instrument transformer(s) with higher burden rated revenue class units; or
 - b. Reduce the burden on the circuit to comply with the name plate of existing instrument transformer(s); or
 - c. Apply correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

CAISO Metered Entity is responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meters in accordance with this BPM to adjust for inaccuracies in the metering circuit.

A7 Special Applications, Configurations and Unique Situations

CAISO Metered Entities are responsible for providing CAISO with the necessary Meter Data and other information to enable CAISO to prepare Settlement Quality Meter Data. For instance, where there is a Generating Unit with multiple generators and auxiliary Loads, CAISO Metered Entity provides appropriate information (i.e. documentation, descriptions, one-line diagrams, etc.) to CAISO of each unit under all combinations of generation and load (e.g. where only one generator is operating but all auxiliary Loads are being supplied).

Section B. Standards for Metering Facilities

This section provides additional details to the standards referred to in Attachment A of this BPM.

The standards referred to in Attachment A of this BPM and this section apply to CAISO Metered Entities and, where the relevant Local Regulatory Authority has not set any standards, to Scheduling Coordinator Metered Entities.

B1 Standards for Existing Metering Facilities

Existing metering facilities are those facilities that were fully installed as of the CAISO Operations Date. Existing Metering Facilities used by CAISO Metered Entities shall meet the following general standards:

- Revenue quality instrument transformers at the generator output level (specifically at all main generators, banks and local distribution load supplied from the generator) must have an accuracy of 0.3% or better,
- Generator auxiliary load metering must have an overall accuracy of 3% or better
- Revenue quality instrument transformers at transmission metering points must have an accuracy of plus or minus 0.3% or better.

Note: Any modifications to Existing Metering Facilities are required to meet the standards outlined in Section B2.

B2 General Standards for CAISO Meters

New meters are those meters that are installed after the CAISO Operations Date. Meters must meet the following general standards:

- They must be revenue quality with a 0.2 Accuracy Class
- They must be remotely accessible, reliable, 60 Hz, three phase, bi-directional, programmable and multifunction electronic meters certified for correct operation at the service voltage
- They must be capable of measuring kWh and kVARh and providing calculated three phase values for kVAh, kVA
- They must have a demand function including cumulative, rolling, block interval demand calculation and maximum demand peaks

-
- There must be battery backup for maintaining RAM and a real-time clock during outages of up to thirty days
 - There must be AC potential indicators on each of the three phases
 - They must be capable of being powered either internally from the bus or externally from an AC source. It is recommended that all CAISO meters have an auxiliary source or emergency backup source of power.
 - They must be capable of providing RMDAPS (MV-90 addressable metering protocol)
 - They must be capable of 60 days storage of kWh, KVARh, and/or 4 quadrant interval data

If there is any inconsistency between these general standards and the detailed standards referred to in paragraphs B3 and B4 of this Part, the detailed standards prevail.

B3 Detailed Standards for New Meters

Exhibit B-1 to this Attachment provides the detailed specifications with which new meters must comply.

B4 Detailed Standards for Coupling Capacitive Voltage Transformer (CCVT), Optical Sensor and New Oil Filled, Wound Instrument Transformers

Exhibit B-2 to this Attachment provides the detailed specifications with which new oil filled, wound instrument transformers must comply.

Exhibit B-1 to Section B

CAISO ENGINEERING SPECIFICATION
FOR POLYPHASE SOLID-STATE
ELECTRICITY REVENUE QUALITY METERS

Attachment B: Section B Exhibit B-1: Table of Contents

- B1: 1 GENERAL INFORMATION
- B1: 2 SCOPE
- B1: 3 METERING FUNCTIONS
- B1: 4 DISPLAY REQUIREMENTS
- B1: 5 METER DIAGNOSTICS
- B1: 6 PROGRAMMING AND SOFTWARE
- B1: 7 COMMUNICATION
- B1: 8 OPTIONAL METER FUNCTIONS
- B1: 9 ACCURACY
- B1: 10 ELECTRICAL REQUIREMENTS
- B1: 11 MECHANICAL REQUIREMENTS
- B1: 12 SECURITY
- B1: 13 METER APPROVAL TESTING
- B1: 14 SAFETY
- B1: 15 DATA SECURITY AND PERFORMANCE
- B1: 16 DOCUMENTATION
- B1: 17 APPLICABLE STANDARDS
- B1: 18 DEFINITIONS

B-1: 1 GENERAL INFORMATION

This Exhibit applies to all solid-state polyphase electricity meters used in revenue metering applications on the CAISO Controlled Grid (meters) and provides the minimum functional and performance requirements for meters. All requirements in this Exhibit are intended to ensure the expected life cycles, security, accuracy, reliability and minimum maintenance requirement of meters. Some requirements, however, are specified to maintain the compatibility and interchangeability of the meter.

B-1: 2 APPLICABILITY

Meters approved under this Exhibit may not be required to have all of the specified features. Meters must meet the specified minimum requirements and the requirements of Section B1: 13 (Meter Approval Testing) of this Exhibit.

B-1: 3 METERING FUNCTIONS**B-1: 3.1 Measured Quantities**

As used in this Exhibit, the term “delivered” applies to Energy flowing out of the CAISO Controlled Grid and the term “received” applies to Energy flowing into the CAISO Controlled Grid.

B-1: 3.1.1 Consumption

The following consumption quantities are required for all meters approved for use on the CAISO Controlled Grid:

- (a) Kilowatt-hours—delivered;
- (b) Kilowatt-hours—received;
- (c) Kilo-var-hours—delivered, received, for each quadrant;
- (d) Kilovoltamp-hours—delivered, received, for each quadrant;
- (e) Ampere-squared-hours; and
- (f) Volts-squared-hours.

B-1: 3.1.2 Demand

The following demand quantities are required for all meters approved for use on the CAISO Controlled Grid:

- (a) Kilowatts—delivered;
- (b) Kilowatts—received;
- (c) Kilovars—delivered, received, for any quadrant; and

- (d) Kilovoltamps—delivered, received, for any quadrant.

B-1: 3.1.3 Power Factors

The CAISO may specify average power factors for the previous demand sub-interval in any quadrant or any combination of two quadrants.

B-1: 3.1.4 Reverse Consumption/Demand

The meter must be programmable to take one of the following actions for reverse consumption and demand quantities:

- (a) Ignore the reverse quantities; and
- (b) Add the reverse quantities to the appropriate consumption and demand quantities.

B-1: 3.2 Basic Default Metering Function

When power is applied to the meter, it must immediately begin recording bi-directional total kilowatt-hours. Received power flow must carry a negative sign. This function must be performed regardless of whether the meter is programmed or not and cannot require a battery. An unprogrammed meter must indicate that it is unprogrammed. CAISO may request a meter to be programmed with a specific program.

B-1: 3.3 Demand Metering Function

Meters must have the following demand metering functions:

- (a) As a minimum, the meter must be programmable for fixed and/or rolling interval demand calculations on bi-directional kilowatts and kilovars;
- (b) The meter is programmable for one minute delivered kilowatt demand (as an approximation of “instantaneous” kilowatts delivered) in addition to the rolling interval demand calculation. The one minute demand is not required to be synchronous with the other demand quantities;
- (c) The meter is programmable for rolling interval demand calculations for any optional demand quantity (see Section B-1: 3.1.2) that CAISO specifies.
- (d) Demand intervals are programmable for durations of 5, 10, 15, 30 or 60 minutes;
- (e) Demand functions are capable of temporary suspension for a programmable time interval after power is restored following a power outage. The length of time is programmable from zero to 60 minutes in one-minute intervals;
- (f) After a demand reset, further manual demand resets are prevented with a programmable lockout time. A demand reset from a meter programmer connected to the optical port is not subject to this delay and can be initiated as frequently as required; and

- (g) If the meter has been programmed for Time-of-Use (TOU) functions, the time at which maximum demand occurred is recorded at the end of that demand interval.

B-1: 3.4 Load Profile Function

Meters have the following load profile functions:

- (a) CAISO may specify that the meter provide load profile recording of interval data for 1 to 4 channels of consumption quantities;
- (b) Date and time is stored with the load recording of interval data;
- (c) Load recording of interval data uses a “wraparound” memory that stores new interval data by writing over the oldest interval data;
- (d) The load recording of interval data function is capable of storing and communicating a minimum of 60 days of 4 or 6 channel, 5 minute interval data, in addition to allowances for event recording (power outages, resets, time sets, etc.);
- (e) The load recording of interval data function has the capacity to count and store at least 4,095 counts in a 5 minute period of time; and
- (f) Load recording of interval data continues while the meter is communicating with a meter programmer connected to the optical port.

B-1: 3.5 Function during Power Disturbances

Meters have the following functions during power disturbances:

- (a) During powerline disturbances such as brownout or outage conditions the meter maintains all meter data as well as time keeping functions. Display and communication functions are not required during these conditions;
- (b) The meter can withstand the following outages during a continuous ten year or longer service without the need to maintain its auxiliary power system, including replacing the battery:
 - i. 20 short outages per year of less than 30 seconds per outage; and
 - ii. 30 days of continuous/cumulative outage;
- (c) During a power outage, critical program and billing data is written to non-volatile memory. When power is restored, data is returned to active memory and data collection resumed;
- (d) Following a power outage, register “catch-up” time is a maximum of 30 seconds. During the “catch-up” time the meter still calculates consumption and demand quantities. Optional inputs and outputs also function during this time;

- (e) During power outages, time is maintained with a cumulative error of no more than 2 minutes per week (0.02%);
- (f) The meter records the date and time of any power outage; and
- (g) Meters may also record the duration of any power outage.

B-1: 3.6 Meter Test Mode Function

Meters have the following meter test mode functions:

- (a) The meter has the capability of a Test Mode function that suspends normal metering operation during testing so that additional consumption and demand from the tests are not added to the meter's totals;
- (b) The Test Mode function is activated by a permanently mounted physical device that requires removal of the meter cover to access or by a meter programmer connected to the optical port;
- (c) Activation of the Test Mode causes all present critical billing data to be stored in non-volatile memory and restored at the time of exit from the Test Mode;
- (d) Upon activation of the Test Mode, register displays accumulate beginning from zero;
- (e) Actuation of the billing period reset device during Test Mode resets the test mode registers;
- (f) After a programmable time-out period, the meter automatically exits from Test Mode and returns to normal metering; and
- (g) The default Test Mode registers for an unprogrammed meter include as a minimum:
 - i. Time remaining in the test interval;
 - ii. Maximum kilowatt block demand; and
 - iii. Total kilowatt-hours.

B-1: 4 DISPLAY REQUIREMENTS

B-1: 4.1 LCD Display

The meter has an electronic display for displaying the consumption and demand quantities. A liquid crystal display (LCD) is preferred.

B-1: 4.2 Viewing Characteristics

Digits for displaying the consumption and demand quantities are a minimum of 7/16" in height and be legible in normal daylight conditions from a distance of six feet by an

observer. The viewing angle is a minimum of fifteen degrees from the front meter face line of sight.

B-1: 4.3 Display Components

The display provides the following:

- (a) Six digits for display of the consumption and demand quantities and constants with decimal points for the three least significant digits;
- (b) Three digits for numeric display identifiers (ID numbers);
- (c) Alternate and Test Mode indication;
- (d) Potential indication for each phase;
- (e) End of interval indicator;
- (f) Visual representation of the magnitude and direction of active energy flow;
- (g) Visual representation of the magnitude and direction of reactive energy flow if the meter is capable of measuring kilovars; and
- (h) Annunciators for most consumption and demand quantities.

B-1: 4.4 Digits

Consumption and demand quantities are programmable for display with leading zeroes in four, five or six digits with a decimal point at any of the least significant three digits.

B-1: 4.5 Time Format

Time is displayed in the 24 hour military format.

B-1: 4.6 Date Format

Date is displayed programmable in either Day/Month/Year or Month/Day/Year format.

B-1: 4.7 Operating Modes

The display has at least three of the following operating modes:

- (a) Normal Mode – in this mode, the display scrolls automatically through the programmed displays for normal meter reading;
- (b) Alternate Mode – in this mode, the display scrolls automatically, scroll manually or freeze for up to one minute for alternate programmed displays;
- (c) Test Mode – in this mode, the display scrolls automatically, scroll manually or freeze for up to one minute for test quantity displays; and

- (d) Segment Check – in this mode, all segments or displays are activated to verify display integrity.

Display ID numbers and display sequence are independently programmable for each of the modes referred to above. Display times are programmable.

B-1: 4.8 Normal Mode

Upon power-up, the meter display operates in the Normal Mode. The meter display operates in Normal Mode until power is disconnected or until either the Alternate Mode or the Test Mode is activated.

B-1: 4.9 Alternate Mode

The Alternate Mode is initiated with a display control device that does not require meter cover removal or with a meter programmer connected to the optical port.

Display Items

As a minimum, the meter provides the display quantities and items for each of the modes referred to in Section B-1: 4.7 as detailed in Attachment 2.

B-1: 4.10 Constants and Correction Factors.

The meter has programmable multi-variable polynomial function multipliers and/or summers to account for instrument transformer ratios, instrument transformer correction factors, the meter constant, line losses and power transformer loss correction.

B-1: 4.11 Identifiers

The meter has programmable identifiers for the meter ID, the person who programmed the meter (programmer ID) and the current program ID. The meter ID shall be capable of eight numeric characters.

B-1: 5 METER DIAGNOSTICS

B-1: 5.1 Self-test

The meter register is capable of performing a self-test of the register software. As a minimum, the self-test is performed at the following times:

- (a) Whenever communications are established to the register;
- (b) After a power-up; and
- (c) Once per day.

B-1: 5.2 Diagnostic Checks

As a minimum, the following diagnostic checks are performed during a self-test:

- (a) Check the backup battery capacity;
- (b) Verify the program integrity; and
- (c) Verify the memory integrity.

B-1: 5.3 Data Overrun

The register is capable of detecting that the maximum amount of data has been exceeded during a demand interval.

B-1: 5.4 Error and Warning Displays

Meters are capable of the following displays:

- (a) Any detected error or warning is stored in memory and an error or warning code displayed on the display;
- (b) Error code displays freeze the display; and
- (c) Warning code displays are programmable to one of the following choices:
 - i. Freeze the warning code on the display; or
 - ii. Warning code display at the end of the Normal, Alternate or Test Modes display sequences.

B-1: 5.5 Error Reset

Error or warning conditions are only reset upon an explicit command invoked via the meter programmer or upon some other explicit action by CAISO.

B-1: 6 PROGRAMMING AND SOFTWARE

The programming software is tested at CAISO and approved by the CAISO Meter Engineering.

B-1: 6.1 Optical Communications Interface.

The meter is capable of communicating with a personal computer through the optical port at a minimum.

B-1: 6.2 Meter Programmers

The CAISO and CAISO Authorized Inspectors are suggested to use Windows based laptops (PC). Field communications with the meter normally is through the optical port, as an option; Ethernet cable, Rs232-Rs 485, or phone modem can be used.

B-1: 6.3 Meter Program

The CAISO meters through the meter manufacturer ensure its supplier provides a meter program software package for use by the CAISO Meter Engineers. The meter program in conjunction with a laptop computer must be capable of loading all meter operating parameters as well as setting time and passwords into the meter.

B-1: 6.4 Field Program Functions

The Field Program as a minimum provides the following functions:

- (a) Set date, time and passwords on the meter;
- (b) Preset the meter consumption registers;
- (c) Send and receive configurations to and from the meter;
- (d) Compare configuration files from the meter with desired files and report discrepancies;
- (e) Read meter billing data and load profile data;
- (f) Generate Meter Data and diagnostic reports for printing;
- (g) Read, display and modify the present settings of field configurable items;
- (h) Execute a billing period reset;
- (i) Reset all consumption and demand quantities; and

B-1: 6.5 Operating System

All software programs shall utilize industry standard operating system software. The operating system software must be currently supported by the software vendor that produces and maintains it. The CAISO requires these programs to maintain operating system compatibility with the CAISO corporate computing standards. The Rate Development, Field, and Field Disk Serialization Programs must be capable of running under CAISO standardized operating systems without any loss of function.

B-1: 6.6 Communication Protocol

The protocol used for communication with the meter through optical port, Ethernet, RS-232, RS485, or the phone modem.

B-1: 6.7 Optical Probe

The meter program supports use of a compatible optical probe connected to the standard PC.

B-1: 7 COMMUNICATION**B-1: 7.1 Optical Port**

The primary communication port to the meter for reading and programming of the internal data is an optically isolated communication port per ANSI C12.13, Type 2 or other serial port.

B-1: 7.2 Baud Rate

The optical port communicates at a minimum of 9600 baud.

B-1: 7.3 Optical Port Location

The optical port is located in the front of the meter and is accessible without removing the meter's cover. The optical port must be functional with the meter cover removed.

B-1: 7.4 Optical Port Cable

There is to be no cable connection between the optical port on the meter cover and the register.

B-1: 7.5 RS232 or RS 485 or RSXXX.

One RSXXX port is provided at the meter for bi-directional communications (with security provisions included) to computers and/or data acquisition devices. The meter must have the capability for being polled every 5 minutes for data by RMDAPS. An optional RSXXX port or ports with read-only access can be provided for others desiring the data. All RSXXX ports are optically isolated.

The meter supports and is implementable with CAISO secure communication system chains, including Meter RSXXX port through CAISO approved communication network to RMDAPS.

B-1: 8 OPTIONAL METER FUNCTIONS**B-1: 8.1 Internal Modem**

CAISO may specify an internal modem having telephone communications at autobaud rates of up to 115000 baud. The modem includes automatic baud select, configurable answer time window and configurable answer counter ring. The ring detect circuitry is affected by spurious voltage rises in the telephone line.

B-1: 9 ACCURACY**B-1: 9.1 ANSI C12.10**

The meter meets or exceeds the accuracy specifications contained in ANSI C12.10 over its entire service life without the need for adjustment.

B-1: 9.2 Factory Calibration

The meter is calibrated to provide the following level of accuracy:

- (a) $\pm 0.2\%$ at full load at power factor of 100%;
- (b) $\pm 0.25\%$ at full load at power factor of 50% lag;
- (c) $\pm 0.25\%$ at full load power factor at 50% lead; and
- (d) $\pm 0.25\%$ at light load at power factor of 100%.

B-1: 9.3 Test Equipment

Meter accuracy and calibration tests, both shop and field, require only standard test equipment that have accuracy of at least plus or minus 0.05% or better. The meter standard is a very accurate energy meter of substantially greater accuracy than the revenue billing meter being tested, or five times greater in accuracy. All the meters used on the CAISO system are required to have accuracy of at least plus or minus 0.25%. No special laboratory-type test equipment or test procedures are required to assure accuracy of the meter.

B-1: 9.4 Creep

The meter may not creep. No data registration can occur for any consumption or demand while the current circuit is open.

B-1: 9.5 Starting Current

The meter starts to calculate consumption and demand quantities when the per-phase current reaches 5 milliamps.

B-1: 9.6 Start-up Delay

The meter starts to calculate consumption and demand quantities less than 3 seconds after power application.

B-1: 9.7 Data Output

Data output has the same accuracy as the meter displays.

B-1: 10 ELECTRICAL REQUIREMENTS**B-1: 10.1 Meter Forms, Voltage Ratings and Classes**

The following forms, voltage ratings and classes of meters are approved for installation on the CAISO Controlled Grid:

- (a) A – Base Type, FORMS 5A and 9A, 69 to 277 Volts, Class 2, 10 and 20;
- (b) Socket – Type, FORMS 5S and 9S, 69 to 277 Volts, Class 2, 10 and 20;
- (c) Switchboard – Type, 2 Element and 3 Element, 69 to 277 Volts, Class 2, 10 & 20;
- (d) Rack mounted meter assemblies – 2 element and 3 element, Class 2, 10 & 20.

B-1: 10.2 Circuit Boards

All circuit boards in the meter are designed to meet CAISO's environmental and electrical testing requirements and the service life and performance expectations detailed in this Exhibit.

B-1: 10.3 LCD Display Connectors

Gold pins encased in an elastomer or carbonized contacts, or some other better construction, are used to connect the LCD display to the register circuit board.

B-1: 10.4 Metering Application

The meter is used to meter electrical service on a continuous duty.

B-1: 10.5 Connections

The meter's internal electrical connections are in accordance with ANSI C12.10.

B-1: 10.6 Meter Register Power Supply

The meter register is powered from the line side of the meter and has provision for external backup power. Neither the normal power supply nor the backup power supply (when so equipped) are fused.

B-1: 10.7 Clock

Clocks meet the following requirements:

- (a) The clock internal to the meter must be accurate within 2 minutes per week (0.02%) when not synchronized to the CAISO Controlled Grid operation line frequency and must be resettable through the CAISO communications interface. CAISO transmits a periodic master synchronizing signal to the meter;

-
- (b) The internal clock must have two modes of operation as follows:
- i. The clock must synchronize with the CAISO Controlled Grid operation line frequency until an outage occurs. During the outage, the clock then synchronizes with its own internal crystal. When power returns, the clock resynchronizes to the CAISO; and
 - ii. The clock must always synchronize with its own internal crystal, as a default;
- (c) The choice of clock mode is programmable.

B-1: 10.8 Batteries

Batteries meet the following requirements:

- (a) When the meter design requires a battery as auxiliary power supply, the requirements of Section B-1: 3.5 apply;
- (b) The battery is secured with a holder securely attached to the meter. The battery holder and electrical connections are designed to prevent the battery from being installed with reversed polarity;
- (c) Replaceable batteries are easily accessible by removing the meter cover. Battery replacement while the meter is in service may not interfere with any of the specified functions. When using short life batteries, external placement of batteries is recommended due to their frequent replacement requirement.
- (d) No fuse external to the battery may be installed in the battery circuit;
- (e) The meter battery provides a minimum carryover capability at 23° C for the functions listed in Section B-1: 3.5 and have a 15 year shelf life; and
- (f) The following information is clearly identified on the battery:
 - i. Manufacturer;
 - ii. Date of manufacture, including year and month (i.e. 9601) or year and week (i.e. 9644);
 - iii. Polarity;
 - iv. Voltage rating; and
 - v. Type.

B-1: 10.9 Electromagnetic Compatibility

The meter is designed in such a way that conducted or radiated electromagnetic disturbances as well as electrostatic discharges do not damage nor substantially influence the meter.

B-1: 10.10 Radio Interference Suppression

The meter may:

- (a) Not generate conducted or radiated radio frequency noise which could interfere with other equipment; and
- (b) Meet FCC Part 15 Class B computing device radio frequency interference standards.

B-1: 11 Mechanical Requirements**B-1: 11.1 GENERAL**

The meter may not pose any danger when operating under rated conditions in its normal working position. Particular attention should be paid to the following:

- (a) Personnel protection against electric shock;
- (b) Personnel protection against effects of excessive temperature;
- (c) Protection against the spread of fire; and
- (d) Protection against penetration of solid objects, dust or water.

B-1: 11.2 Corrosion Protection

All parts of the meter must be effectively protected against corrosion under normal operating conditions. Protective coatings may not be damaged by ordinary handling nor damaged due to exposure to air. The meter is capable of operating in atmospheres of up to (and including) 95% relative humidity condensing.

B-1: 11.3 Solar Radiation

The functions of the meter are not impaired, the appearance of the meter may not be altered and the legibility of the meter nameplate and other labels may not be reduced due to exposure to solar radiation throughout the service life of the meter.

B-1: 11.4 Corrosive Atmospheres

CAISO may specify additional requirements for meters used in corrosive atmospheres.

B-1: 11.5 Meter Package

The meter package meets the following requirements:

- (a) The socket meter's dimensions are in accordance with ANSI C12.10;
- (b) The socket meter is designed for mounting outdoors in a standard meter socket;
- (c) Meters have a twist-on self-locking cover in accordance with ANSI C12.10 requirements. The meter cover:
 - i. Not contain a metal or conducting locking ring;
 - ii. Be resistant to ultraviolet radiation;
 - iii. Be sealed in such a way that the internal parts of the meter are accessible only after breaking the seal(s);
 - iv. For any non-permanent cover deformation, not prevent the satisfactory operation of the meter;
 - v. For the "sprue" hole (mold fill hole), not affect the ability to read the meter; and
 - vi. Have an optical port per ANSI C12.13, Type 2.
- (d) The method of securing the socket meter to the meter socket is with either a sealing ring or a high security sealing device;
- (e) The billing period demand reset device accommodates a standard electric meter seal and remains in place with friction if not sealed; and
- (f) Filtered ventilation is provided in the base of the meter to prevent condensation inside the meter.

B-1: 11.6 Nameplate

The meter nameplate will:

- (a) Comply with the minimum information requirements of ANSI C12.10;
- (b) Includes the meter's serial number and the date of manufacture. The manufacturing date shall include the year and month (i.e. 9601) or the year and week (i.e. 9644);
- (c) Has the following attributes:
 - i. Is mounted on the front of the meter;
 - ii. Is not attached to the removable meter cover;

- iii. Is readable when the meter is installed in the meter socket or panel; and
 - iv. Does will not impair access for accuracy adjustment or field replacement of components (such as the battery).
- (d) Includes ANSI standard bar coding; and
- (e) Includes an easily erasable strip with minimum dimensions of 3/8 inch by 1½ inches for penciling in items such as meter multiplier or the meter tester's initials.

B-1: 12 SECURITY**B-1: 12.1 Billing Period Reset**

Operation of the billing period demand reset mechanism requires breaking of a mechanical sealing device. Use of common utility-type sealing devices are accommodated.

B-1: 12.2 Meter Password

The meter is programmable by the meter programmer with up to four unique passwords to prevent unauthorized tampering by use of the optical port or the optional modem. Passwords must be a minimum of four (4) alpha/numeric characters. Access rights and capabilities are individually programmable for each password. Passwords can also be changed via MV-90 translation module.

B-1: 12.3 Test Mode

Removal of the meter cover or a software command using a password is required to activate the Test Mode.

B-1: 12.4 Program Security

At least four levels of security are available for the meter program. These levels include:

- (a) Read Register— the user can only read billing and load profile data;
- (b) Read Register— the user can only read billing and load profile data, and perform a billing period reset;
- (c) Read/Modify Register— the user can perform functions listed in 12.4(a) and 12.4(b), plus download meter configuration files and operate other features of the meter program; and
- (d) Read/Modify/Program Register— the user can perform functions listed in 12.4(a), 12.4(b) and 12.4(c), plus develop meter configuration files and operate additional features of the meter program.

B-1: 12.5 Revenue Protection

Meters that help prevent Energy diversion are preferred.

B-1: 13 METER APPROVAL TESTING**B-1: 13.1 General Requirement**

This Section outlines the testing required by CAISO to assure the quality of meters, CAISO does not approve meters that have not undergone the testing referred to in this Section.

CAISO Testing using NIST Traceable Laboratory

In addition to the required manufacturer testing specified in this Section, CAISO reserves the right to require a NIST traceable laboratory test data resulting from the performance of tests as outlined in this Section.

In addition to the applicable testing requirements of the ANSI C12 standards, the qualification tests specified in this Section are conducted to confirm correct operation of the meter. The qualification testing is required for new meter designs and for meter product changes.

The NIST traceable laboratory ensures that it provides a certified test report documenting the tests and their results. The test report is signed by the NIST traceable laboratory and includes all charts, graphs and data recorded during testing.

B-1: 13.2 Meter Failure Definition

A meter is designated as failed if any of the following events occur:

- (a) Failure of the meter to perform all of the specified functions;
- (b) Failure of the meter to meet the technical performance specifications included in this Exhibit;
- (c) Signs of physical damage or performance degradation as a result of a test procedure, including effects which could shorten the service life of the meter;
- (d) The occurrence of an unexpected change of state, loss of data or other unacceptable mode of operation for the meter as a consequence of a test procedure; and
- (e) Failures are classified as a hardware, firmware or software failure or a combination according to the following definitions:
 - i. Firmware failures are errors made during the fabrication of programmable read only memory (PROM) chips such that the required program or instruction set that the microprocessor is to perform is incorrect;

- ii. Hardware failures are failures that are physical in nature and directly traceable to the component level. Visual observances such as discoloration, cracking, hardening of cables, poor solder joints, etc. are also included. Failures of DIP switches, jumpers, and links are also included; and
- iii. Software failures are failures such as the loss or unintended change of data, the inability to program the meter, the loss of the meter program or the erroneous output or display of false information.

B-1: 13.3 Meter Design Rejection Criteria

A meter design is rejected if any of the following events occur:

- (a) The failure of one meter during one test procedure and the failure of a second meter during another test procedure; and
- (b) The failure of two or more meters during the same test procedure.

B-1: 13.4 Test Setup

- (a) The meter is connected to its normal operating supply voltage with a fully charged Power Failure Backup System. The meter is energized throughout the duration of the test procedures, unless otherwise stated;
- (b) Before testing commences, the meter is energized for a minimum of two hours at room temperature;
- (c) All tests are conducted at room temperature unless otherwise specified; and
- (d) The meter is loaded to the nameplate test amperes at 100% power factor for all tests unless otherwise indicated.

B-1: 13.5 Functional Test (No Load Test)

This test confirms the operation of the meter functions in accordance with this Exhibit:

- (a) The meter is energized with no load;
- (b) The meter is programmed with CAISO supplied parameters using a meter programmer;
- (c) Operation of the specified functions are verified over 24 hours by observing the meter display and by interrogating the contents of meter registers via a meter programmer; and
- (d) To pass this test, the meter operates as specified with no observed anomalies.

B-1: 13.6 Accuracy Test

This test confirms the accuracy of the meter:

- (a) The accuracy of the meter is tested for all combinations of the following conditions:
 - i. at ambient temperature, 85°C and -20°C;
 - ii. at power factors of 100%, 50% lag and 50% lead; and
 - iii. at 0% to 120% of class current;
- (b) Accuracy curves are provided for all combinations of the conditions; and
- (c) To pass this test, the meter has the indicated accuracy at ambient temperature for the following load conditions:
 - i. $\pm 0.2\%$ at Full load at power factor of 100%;
 - ii. $\pm 0.25\%$ at Full load at power factor of 50% lag;
 - iii. $\pm 0.25\%$ at Full load at power factor of 50% lead; and
 - iv. $\pm 0.25\%$ at Light load at power factor of 100%.

B-1: 13.7 Line Voltage Variation Test

This test confirms the meter's correct operation under varying line voltage conditions:

- (a) The meter is tested at line voltages ranging from 80% to 120% of rated voltage under the following load conditions:
 - i. Full load at power factor of 100%; and
 - ii. Light load at power factor of 100%; and
- (b) To pass this test the meter meets the following criteria:
 - i. Operate as specified;
 - ii. Have an accuracy as specified in Section 13.6(c) throughout the 80% to 120% voltage range; and
 - iii. The power failure backup system shall not take over when the voltage is above 80% and below 120% of rated.

B-1: 13.8 Momentary Power Loss

This test confirms the meter's ability to withstand momentary power outages:

-
- (a) The test is performed by opening the AC power supply input for the specified duration;
 - (b) Twelve tests are conducted using the following sequence:
 - i. Energize the meter;
 - ii. Simulate a power loss of 0.5 cycles at 60 hertz;
 - iii. Lengthen each succeeding simulated power outage by 0.5 cycles until a duration of 6.0 cycles is attained; and
 - iv. The start of each successive test shall be delayed by one minute; and
 - (c) To pass this test, the meter operates as specified with no observed anomalies.

B-1: 13.9 Power Failure Backup System Test

This test confirms the carryover capability of the power failure backup system:

- (a) This test is conducted at ambient temperature using a new or fully charged battery;
- (b) The test is conducted using the following sequence:
 - i. Energize the meter at full load for two hours;
 - ii. De-energize the meter for 24 hours; and
 - iii. Verify the integrity of programs and metering data stored in memory; and
- (c) To pass this test, the meter operates as specified with no observed anomalies.

B-1: 13.10 Brownout and Extended Low Voltage Test

This test confirms the meter's ability to withstand brownouts and extended low voltage conditions:

- (a) The test is conducted using the following sequence:
 - i. Energize the meter and verify correct operation;
 - ii. Slowly lower the line voltage to 80% of nominal;
 - iii. Operate the meter at this voltage level for 6 hours;
 - iv. Verify correct meter operation;
 - v. Lower the line voltage to 50% of nominal;
 - vi. Operate the meter at this voltage level for 6 hours; and

- vii. Verify correct operation of the meter and the power failure backup system; and

(b) To pass this test, the meter operates as specified with no observed anomalies.

B-1: 13.11 Effect of Power Failure Backup System Voltage Variation on Clock Accuracy

This test confirms the effects of the battery voltage on the meter's clock accuracy:

- (a) The meter is tested with the battery disconnected and an auxiliary DC power supply connected to the battery carryover circuit. The DC power may be varied from 95% to 105% of nominal battery voltage; and
- (b) To pass this test, the accuracy of the meter clock must be within 0.02% (2 minutes per week) with a voltage variation of 5 % of nominal battery voltage at ambient temperature.

B-1: 13.12 Effect of Temperature Variation on Clock Accuracy

This test confirms the effects of temperature on the meter clock accuracy:

- (a) This test is conducted with the register in the battery carryover mode;
- (b) The temperature may be varied from 85°C to -20°C;
- (c) The meter is exposed to each temperature for a least 2 hours prior to testing; and
- (d) To pass this test, the accuracy of the meter clock must be within 0.02% (2 minutes per week) at ambient temperature, 85°C, and -20°C.

B-1: 13.13 Temperature Cycle Test

This test confirms the effects of an accelerated temperature cycle on the meter:

- (a) The meter cover must be removed during this test;
- (b) The test duration is 7 days (168 hours);
- (c) The temperature is cycled once per 24 hour period;
- (d) Temperature is varied linearly during the tests at a constant rate not to exceed 20°C per hour;
- (e) Humidity is not controlled during the test;
- (f) The meter must be de-energized during the fourth and fifth cycles of the test to verify the performance of the power failure backup system during temperature fluctuations;
- (g) Each 24 hour cycle consists of the following:

- i. Begin test at +20°C (or room temperature if within 5°C);
 - ii. Ramp up to +85°C in approximately 3.25 hours;
 - iii. Hold at +85°C for approximately 10.75 hours;
 - iv. Ramp down to -20 C in approximately 5.25 hours;
 - v. Hold at -20°C for approximately 2.75 hours;
 - vi. Ramp up to +20°C in approximately 2.00 hours; and
 - vii. Begin next 24 hour cycle or end test after 7 cycles; and
- (h) To pass this test, the meter operates as specified with no observed anomalies for the entire test period.

B-1: 13.14 Humidity Cycle Test

This test confirms the effects of an accelerated humidity cycle on the meter:

- (a) The meter cover is removed during this test, or a meter cover with a large hole at the bottom may be substituted;
- (b) The duration of the test is 24 hours;
- (c) Condensation may form on the meter during the test;
- (d) Temperature may be varied linearly during the tests at a constant rate not to exceed 20°C per hour;
- (e) Humidity may not be controlled during temperature changes;
- (f) The test consists of the following sequence:
 - i. Begin at +20°C (or room temperature if within 5°C);
 - ii. Ramp up to +85°C in approximately 3.25 hours;
 - iii. Ramp up to a relative humidity of 95% in approximately 1 hour;
 - iv. Hold at +85°C at a relative humidity of 95% ±1% for approximately 14.5 hours;
 - v. Ramp down to +20°C in approximately 3.25 hours;
 - vi. Concurrently with Section 13.14(f)v. ramp down to a relative humidity of 75% in approximately 15 minutes;

- vii. Hold relative humidity at 75% for remainder of temperature ramp down; and
 - viii. Hold at 20°C at a relative humidity of 75% ±1% for approximately 2 hours; and
- (g) To pass this test, the meter operates as specified with no observed anomalies for the entire test period.

B-1: 13.15 Insulation Withstand Test

This test confirms the insulation levels of the meter:

- (a) The meter may not be energized for this test;
- (b) The insulation between power line voltage and current carrying parts and any other metallic or conductive part may be tested by applying 2500 volts rms, 60 Hz for a period of one minute; and
- (c) To pass this test the leakage current may not exceed one milliamp for the duration of the test and the meter shall operate after completion of the test.

B-1: 13.16 Standard Waveform Surge Withstand Test

This test confirms the ability of the meter to withstand voltage transients:

- (a) The meter is energized but not loaded during the test;
- (b) The test is conducted in accordance with the latest recognized industry standards;
- (c) The oscillatory test wave is applied at a repetition rate of 100 tests per second for 25 seconds;
- (d) The test signal is applied in both the common and transverse modes;
- (e) The test is conducted on all voltage, current, and optional equipment inputs and outputs;
- (f) This test is performed two times with a maximum period of 1 minute between tests; and
- (g) To pass this test, the meter operates as specified with no observed anomalies;

B-1: 13.17 Fast Transient Waveform Surge Withstand Test

This test confirms the ability of the meter to withstand fast voltage transients:

- (a) The meter is energized but not loaded during the test;

- (b) This test is conducted in accordance with the latest industry recognized standard;
- (c) The unipolar test wave is applied at a repetition rate of 100 tests per second for 25 seconds;
- (d) The test signal is applied in both the common and transverse modes;
- (e) The test is conducted on all voltage, current, and optional equipment inputs and outputs;
- (f) This test is performed two times with a maximum period of 1 minute between tests; and
- (g) To pass this test, the meter operates as specified with no observed anomalies.

B-1: 13.18 Powerline Surge Voltage and Current Test

This test confirms the ability of the meter to withstand power line voltage and current surges:

- (a) The meter is energized but not loaded during the test;
- (b) The test is performed using the unipolar and the ring waveform specified in the latest industry recognized standard;
- (c) The test surges are applied to the power line in both the normal and common modes;
- (d) The following number of surges is applied at the indicated voltages:
 - i. 12 surges at 6 kV;
 - ii. 12 surges at 5 kV; and
 - iii. 36 surges at 4 kV.
- (e) The first test surges at 5 kV and 6 kV are injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge is shifted 15 degrees on the positive half-cycle of the waveform up to 180 degrees;
- (f) The first test surge at 4 kV is injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge is shifted 15 degrees on both the positive and negative half-cycles of the waveform up to 360 degrees;
- (g) Sufficient time must be allowed in between test surges for the electronic components to return to normal operating temperatures. A minimum of 5 minutes is allowed between each surge test;
- (h) The applied test signals are monitored and recorded. The meter under test is monitored to confirm that correct operation is maintained;

- (i) After the tests each meter is inspected for visible damage, such as signs of arcing, etc.; and
- (j) To pass this test, the meter operates as specified with no visible damage observed.

B-1: 13.19 Electrostatic Susceptibility Test

This test verifies the ability of the meter to withstand electrostatic discharges:

- (a) This test is tested in accordance with the latest revision of Military Handbook DOD-HDBK-263;
- (b) The test generator simulates a human body with a capacitance of 100 picofarads and a series resistance of 1500 ohms;
- (c) The test probe is a 3/8 inch rod with a rounded tip;
- (d) The following procedures are followed:
 - i. Test all surfaces, including switches and buttons and other components that are contacted by personnel under normal handling, installation and use of the meter. This includes any safety grounded or neutral terminals on the exterior of the meter enclosure;
 - ii. With the test probe voltage set at 10 kV, contact each of the above surfaces with the probe;
 - iii. With the test probe voltage set to 15 kV, locate the probe to within approximately 0.5 inch (avoiding contact) with each of the above surfaces; and
 - iv. The functions of the meter are periodically verified for correct operation; and
- (e) To pass this test, the meter operates as specified with no observed anomalies.

B-1: 13.20 Visual Inspection

This test is performed after all of the other tests except the shipping test have been performed:

- (a) Visual inspection is performed for all electronic circuit boards in the meter; and
- (b) To pass this test, the meter may not have any defect which would result in rejection under the latest recognized industry standards on any electronic circuit board.

B-1: 13.21 Shipping Test

This test confirms the ability of the meter and its packaging to withstand the rigors of shipping and handling:

- (a) The meter may not be energized during this test, but may be programmed and operating in the power backup mode;
- (b) The packaged meter is subjected to the following tests:
 - i. the National/International Safe Transit Association Pre-shipment Test Procedures, Project IA; and
 - ii. Method B, Single Container Resonance Test, of the latest revision of American Society for Testing and Materials (ASTM) Standard D-999. Test intensities, frequency ranges and test durations meet or exceed the recommended values of ASTM D-999; and
- (c) To pass this test, the meter is inspected and tested to verify that no damage occurred and that the time and all stored data is correct.

B-1: 14 SAFETY**B-1: 14.1 Hazardous Voltage**

Hazardous voltages are not easily accessible with the meter cover removed.

B-1: 14.2 Grounding

All accessible conductive parts on the exterior of the meter and conductive parts that are accessible upon removal of the meter cover are be electrically connected to the meter grounding tabs. All connections in the grounding circuit are made with an effective bonding technique.

B-1: 14.3 Toxic Materials

No materials that are toxic to life or harmful to the environment are exposed in the meter during normal use.

B-1: 14.4 Fire Hazard

Materials used in the construction of the meter do not create a fire hazard.

B-1: 15 DATA SECURITY AND PERFORMANCE

- (a) Manual access for changing data or reprogramming requires the physical removal or breaking of a CAISO seal by CAISO or a CAISO Authorized Inspector.
- (b) No loss of data may occur as a result of the following events within design specifications:

- i. Power outages, frequency changes, transients, harmonics, reprogramming, reading; and
 - ii. Environmental factors—dampness, heat, cold, vibration, dust.
- (c) 5-minute interval data for all channels for the most recent 60-day period is always available and accessible via the communications interface or the optical interface.

B-1: 16 DOCUMENTATION**B-1: 16.1 Hardware Documentation to Be Provided For CAISO Review**

- (a) Drawing(s) showing the external meter connections.
- (b) Instruction booklets detailing the necessary procedures and precautions for installation of the meter provided for use by field personnel during initial installation written in the style of a step-by-step outline.
- (c) One (1) technical/maintenance manual and one (1) repair manual provided for each meter style. These manuals must be sufficiently detailed so that circuit operation can be understood and equipment repair facilitated.
- (d) The above documents must be submitted for approval by CAISO. Approval of documents by CAISO does not relieve any responsibility for complying with all the requirements of this Exhibit.

B-1: 16.2 Software

A complete set of manuals detailing the operation of the meter program and programming software is provided to CAISO. These manuals must explain to a person with only basic computer knowledge how to generate and download meter configuration files.

B-1: 17 APPLICABLE STANDARDS

The standards referred to in Attachment A of this BPM apply to all meters.

B-1: 18 DEFINITIONS

The following terms and expressions used in this Exhibit are detailed as set forth below:

“ambient temperature” means temperature of $23^{\circ}\pm 2^{\circ}$ Celsius.

“average power factor” means the power factor calculated using the average active and reactive power flows over the latest demand interval.

“delivered” means Energy (active, reactive, or apparent) that flows from the CAISO Controlled Grid to an End-User.

“failed meter” means a meter in which any part or component, except the removable battery, has failed.

“failure” means any hardware, firmware or software failure, or any combination.

“hazardous voltage” means any voltage exceeding 30 volts rms.

“meter” means all single phase and three phase electronic meters.

“meter program” means a software package that allows the user to download meter configuration files into the meter and perform other testing and maintenance activities.

“meter programmer” means the device used for meter reading/programming.

“MSDS” means the Material Safety Data Sheet.

“power failure backup system” means a sub-system in the meter that provides power to the electronic circuitry when the normal power line voltage is below operating limits. The sub-system usually consists of a battery and may or may not include a super capacitor.

“quadrant” means the term used to represent the direction of power flows (active and reactive) between the CAISO Controlled Grid and an End-User. The 4 quadrants are defined as follows:

- (a) Quadrant 1 – shall measure active power and reactive power delivered by the CAISO Controlled Grid;
- (b) Quadrant 2 – shall measure active power received by CAISO Controlled Grid and reactive power delivered by the CAISO Controlled Grid;
- (c) Quadrant 3 – shall measure active power and reactive power received by the CAISO Controlled Grid; and
- (d) Quadrant 4 – shall measure active power delivered by CAISO Controlled Grid and reactive power received by the CAISO Controlled Grid.

“received” means Energy (active, reactive or apparent) that flows from a Generator to the CAISO Controlled Grid.

“temperature tolerance” means $\pm 2^\circ$ Celsius.

Attachment 1

Physical and Electronic Attribute Criterion for Electronic Meters

Test / Inspection Description	Pass	Fail
1. Bayonets		

Test / Inspection Description	Pass	Fail
A. Missing or loose parts, i.e., cotter pin, arc gap, etc.		
2. Meter Base		
A. Any cracked and/or missing/damaged gasket		
B. Any broken leg		
C. Missing or loose voltage link or screw		
D. Any missing or loose arc gaps		
E. Missing or damaged ventilation screen or filter on applicable meter		
F. Sealing hole unusable for sealing		
G. Any chips on upper half of meter (gasket ring area)		
H. Any chips which may jeopardize meter integrity		
I. Any sign of water damage in meter such as corrosion, oxidation, stain		
J. Missing or loose rivets holding frame to base		
3. Meter Frame		
A. Nameplate data incorrect or flawed		
B. Missing or loose hardware on frame		
4. Module		
A. Loose or defective power connectors		
B. Improper routing of voltage leads		
C. Improper fit (loose or crooked)		
D. Crimped or pinched voltage leads		
E. Incorrect module		
F. Calibration screw access should not be significantly affected (or covered)		
5. Meter Cover		
A. Wiring to communication port is correct & solid		
B. Proper meter cover is used for meter type and class		
C. Mechanical reset mechanism works properly		
D. Proper alignment, positioning, and operation of all cover mechanisms		
6. Electronic Register		
A. Program register to verify acceptance of rate schedule		
B. Check display that all segments are operational		
C. Check battery carryover function, if appropriate		
D. Check register tracking		
E. Check for any visual defects in the register assembly		

Only scratches and/or chips that are cosmetically or functionally objectionable are classified as defective and failing.

Attachment 2

Meter Display Items

Display Item	Normal Mode	Alternate Mode	Test Mode
Minimum Requirements for Delivered kWh			
Complete Display (Segment) Test	x	x	x
Demand Reset Count		x	x
Demand Reset Date		x	
Instantaneous kW	x	x	x
Interval length		x	
Minutes of Battery Use		x	
Present time	x	x	x
Program ID		x	
kWh	x	x	
Maximum kW	x	x	
Complete Display (Segment) Test	x	x	x
Demand Reset Count		x	x
Demand Reset Date		x	
Instantaneous kW	x	x	x
Interval length		x	
Minutes of Battery Use		x	
Present time	x	x	x
Program ID		x	
kWh	x	x	
Maximum kW	x	x	
Additional requirements for kVAh (cont.)			
Total Delivered kVAh		x	
Total Received kVAh		x	
Additional requirements for Power Factor (if specified)			
Quadrant 1 Average Power Factor		x	
Quadrant 2 Average Power Factor		x	
Quadrant 3 Average Power Factor		x	
Quadrant 4 Average Power Factor		x	

Display Item	Normal Mode	Alternate Mode	Test Mode
Total Average Power Factor Delivered		x	
Total Average Power Factor Received		x	

Exhibit B-2 to Section B

CAISO SPECIFICATION
FOR CERTIFICATION OF COUPLING CAPACITIVE VOLTAGE TRANSFORMER (CCVT),
OPTICAL SENSOR AND OIL-FILLED,
WOUND INSTRUMENT TRANSFORMERS
FOR CAISO REVENUE METERING

B-2: 1 Purpose

This Exhibit specifies the technical requirements for reliable high-accuracy current transformers (CT) and voltage transformers (VT) to be used for revenue quality metering on the CAISO Controlled Grid. The CAISO instrument transformers must meet the applicable provisions of ANSI C57.13-1978 (R1986), in addition to the provisions in this Exhibit.

B-2: 2 Scope

B-2: 2.1 This Exhibit applies to the following:

- Oil-filled, CCVT and Optical Sensor CTs & VTs.
- All other CTs & VTs indoor or outdoor instrument transformers 10 kV BIL through 350 kv BIL (0.6 kv NSV through 69 KV NSV).

B-2: 2.2 This Exhibit applies only to the following above CTs & VTs, which are < 35kv and > 525kv must be individually specified in accordance with the engineered installations. This exhibit also applies to metering transformers.

B-2: 3 Standards

All instrument transformers covered by this Exhibit are designed, manufactured, tested and supplied in accordance with the applicable standards referred to in Attachment A of this BPM.

B-2: 4 Definitions

“**hermetically sealed**” means completely sealed by fusion, soldering, etc., so as to keep air or gas from getting in or out (i.e. airtight).

“**metering unit**” means one or more voltage element(s) and one or more current element(s) contained in one common housing.

“**BIL rating**” means basic lightning impulse insulation level.

“**burden rating**” means the total impedance (in ohms) that can be connected to the secondary circuit(s) of an instrument transformer while maintaining metering accuracy of plus-or-minus 0.3%

B-2: 5 Specifications**B-2: 5.1 General**

All instrument transformers covered by this Exhibit have a minimum BIL rating appropriate for the designated nominal system voltage:

- 0.6 kV – 10 kV BIL

- 4.8 kV – 14.4 kV – 60 kV BIL
- 25 kV – 125 kV BIL
- 34.5 kV – 200 kV BIL
- 60 - 69 kV – 350 kV BIL
- 115 kV – 550 kV BIL
- 230 kV – 900 kV BIL
- 525 kV – 1800 kV BIL

B-2: 5.2 Current Transformers

B-2: 5.2.1 Current transformer windings (typical configurations) are either:

- (a) A single primary winding and single secondary winding with dual ratio tap;
- (b) A dual primary winding and a single ratio tap;
- (c) A single primary winding and one or more secondary windings with dual ratio tap(s);
or
- (d) Other combinations as available and approved by CAISO.

B-2: 5.2.2 Rated primary current

The rated primary current must be as specified by the CAISO Metered Entity.

B-2: 5.2.3 Rated secondary current

The rated secondary current must be 1 or 5 amperes @ rated primary current depending on the type of CT.

B-2: 5.2.4 Accuracy and burden

All current transformers have an accuracy and burden of:

- (a) Standard – plus-or-minus 0.3% @ B0.1 - 1.8 ohms, 10% - 100% rated current; or
- (b) Optional – plus-or-minus 0.15 % @ B0.1 - 1.8 ohms, 5% - 100 % rated current.

B-2: 5.2.5 Continuous current rating factor

All current transformers have a continuous current rating factor (or better) of:

- (a) Standard – 1.5 @ 30 degrees C Ambient; or

(b) Optional – 1.0 @ 30 degrees C Ambient.

B-2: 5.2.6 Short time thermal current rating

The short time thermal current rating varies with transformer rating as follows:

25/50: 5 ratio, 4 kA RMS to 1500/3000:5 ratio, 120 kA RMS.

B-2: 5.2.7 Mechanical short time current rating

The mechanical short time current rating varies with transformer rating as follows:

25/50:5 ratio, 3 kA RMS to 1500/3000:5 ratio, 90 kA RMS.

B-2: 5.3 Voltage Transformers

B-2: 5.3.1 Transformer windings consist of a single primary winding and one or more tapped secondary windings.

B-2: 5.3.2 Rated primary voltage, as specified by the CAISO Metered Entity, must be 34,500 volts through 138,000 volts, L-N.

B-2: 5.3.3 Rated secondary voltage must typically be 115/69 volts.

B-2: 5.3.4 The ratio of primary to secondary windings must be 300/500:1 through 1200/2500:1.

B-2: 5.3.5 Accuracy and burden

All voltage transformers have accuracy and burden (or better) of:

(a) Standard – plus-or-minus 0.3% through B. ZZ @ 90% through 110% of nominal voltage; or

(b) Optional – plus-or-minus 0.15% through B. Y 90% through 110% of nominal voltage.

B-2: 5.3.6 Thermal burden rating

All voltage transformers have a thermal burden rating (or better) of:

(a) 34.5 kV – 2500 VA, 60 hertz

(b) 60 kV & 69 kV – 4000 VA, 60 hertz

(c) 115 kV – 6000 VA, 60 hertz

(d) 230 kV – 12000 VA, 60 hertz

(e) 525 kV – 24000 VA, 60 hertz.

B-2: 5.4 Combination Current/Voltage Transformers (metering units)

Metering units maintain the same electrical, accuracy and mechanical characteristics as individual CTs and VTs. Physical dimensions may vary according to design.

B-2: 5.5 Grounding

The neutral terminal of the VT must exit the tank via a 5kV-insulated bushing and be grounded by means of a removable copper strap to a NEMA 2-hole pad.

B-2: 5.6 Primary Terminals

The primary terminals must be tin-plated NEMA 4-hole pads (4"x4").

B-2: 5.7 Paint

Exterior metal non current-carrying surfaces must be painted with a weather-resistant paint system consisting of one primer and two industry recognized gray finish coats. As an option, for high-corrosion areas, special corrosion-resistant finishes (e.g. zinc-rich paint, stainless steel tank) may be used.

B-2: 5.8 Porcelain

Porcelain must be of one-piece wet-process, glazed inside and outside. The outside color must be in accordance with industry recognized gray glaze. The minimum creepage and strike-to-ground distances for various voltages must be as follows:

Voltage (nominal kV)	Creepage (inches)	Strike (inches)
34.5	34	13
60 & 69	52	24
115	101	42
230	169	65
230 (1050 BIL)	214	84

B-2: 5.9 Insulating Oil

The nameplate must be of non-corroding material and must indicate that the dielectric fluid is free of polychlorinated biphenyls by the inscription:

“CONTAINS NO PCB AT TIME OF MANUFACTURE”.

B-2: 5.10 Accessories

All units must be equipped with the following standard accessories, if applicable:

- 1/2" brass ball drain valve with plug
- 1" oil filling opening with nitrogen valve
- Magnetic oil level gauge, readable from ground level
- Primary bypass protector
- Sliding CT shorting link
- Four 7/8"x 2-3/8" mounting slots
- Four 1" eyebolts on base for four-point lifting sling
- 1/4" threaded stud secondary terminals
- Two conduit boxes, each with three 1-1/2" knockout

B-2: 6 Testing

The CAISO Metered Entity must ensure that, before shipment, each transformer is subjected to testing as prescribed by recognized industry standards and other tests including:

- (a) Applied voltage test for primary and secondary winding withstand to ground;
- (b) Induced voltage test for proper turn-to-turn insulation;
- (c) Accuracy test for ratio correction factor and phase-angle verification to confirm 0.3% metering accuracy per recognized industry standards;
- (d) Ratio test;
- (e) Insulation Power Factor test;
- (f) Polarity test;
- (g) Leak test to assure integrity of gaskets and seals; and
- (h) Partial Discharge Test may be done in conjunction with applied voltage testing to assure proper line-to-ground withstand.

The certified tests must be submitted to the CAISO.

B-2: 7 Required Information

The following drawings and information are required:

-
- (a) One set of drawings showing physical dimensions including mounting holes and primary CT terminal details, nameplate. The CAISO Metered Entity must ensure that it receives a schematic of connections from its supplier; and
 - (b) A copy of quality controls/quality assurance (QC/QA) manuals applicable to production of the transformer(s).

Section C. Transformer and Line Loss Correction Factors

C1 Introduction

Transformer loss correction refers to the practice of metering electrical Energy delivered at a high-voltage billing point using metering equipment connected on the low-voltage side of the delivery point. The metering equipment is provided with a means of correction that adds to, or subtracts from, the actual active and reactive metered values in proportion to losses that are occurring in the transformer.

Transformer losses are divided into two parts:

- The core or iron loss (referred to as the no-load loss); and
- The copper loss (referred to as the load loss).

Both the no-load loss and the load loss are further divided into Watts and VAR components.

The no-load (iron) loss is composed mostly of eddy current and hysteresis losses in the core. No-load loss varies in proportion to applied voltage and is present with or without load applied. Dielectric losses and copper loss due to exciting current are also present, but are generally small enough to be neglected.

The load (copper) watt loss ($I^2 +$ stray loss) is primarily due to the resistance of conductors and essentially varies as the square of the load current. The VAR component of transformer load loss is caused by the leakage reactance between windings and varies as the square of the load current.

Line losses are considered to be resistive and have I^2R losses. The lengths, spacings and configurations of lines are usually such that inductive and capacitive effects can be ignored. If line losses are to be compensated, they are included as part of the transformer load losses (Watts copper).

The coefficients, which are calculated at the calibration point of the meter, are entered into the meter as Percent Loss Watts Copper (%LWCU), Percent Loss Watts Iron (%LWFE), Percent Loss VARs Copper (%LVCU), and Percent Loss VARs Iron (%LVFE).

Percent losses are three phase losses expressed as a percent of the full load on a meter.

The formulas used to determine the compensation values at a particular operating point are:

$$\text{Compensation Value} = \frac{\text{WATTS}}{\text{Value}} = \frac{\text{Measured Voltage}^2}{\text{Calibration Point Voltage}^2} * \%LWFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LWCU$$

$$\text{Compensation} = \frac{\text{VARs}}{\text{Value}} = \frac{\text{Measured Voltage}^4}{\text{Calibration Point Voltage}^4} * \%LVFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LVCU$$

C2 Calculating Transformer Loss Constants

Transformer loss correction calculations with electronic meters are accomplished internally with firmware. Various setting information and test data is required to calculate the four values which are to be programmed into the meter.

The following information is required about meter installations:

- The transformer high voltage (HV) voltage rating
- The transformer kVa rating
- The transformer high voltage (HV) tap settings
- The transformer low voltage (LV) tap settings
- The transformer connection (wye or delta)
- The transformer phases (1 or 3)
- The voltage transformer (VT) ratio
- The current transformer (CT) ratio
- The number of meter elements
- The following data from a transformer test report is required:
 - No-load (iron) loss
 - Full-load (copper) loss
 - Percent impedance
 - Percent excitation current

The test data required may be obtained from the following sources:

- The manufacturer's test report
- A test completed by a utility or independent electrical testing company

If the transformer bank is used to deliver power to more than one entity (that is, it is a joint use transformer bank) additional data is required, including the:

- Maximum available kVA from the transformer bank
- Contracted amount of load to be compensated in kW
- Contractual power factor amount to be used in calculations

C3 Calculating Line Loss Constants

Line loss correction calculations with electronic meters are accomplished internally with firmware. A variety of information about a radial line is required to calculate the value which is programmed into the meter. Resistance of the conductors are used to calculate a value which is added to the Watts copper loss value which is programmed into the meter. The following information is required about the radial line:

- The line type
- The AC Ohms per mile or per unit losses
- The length in miles of each type of line
- Lines shared with multiple resources

C4 Applications

Joint Use Transformers

Where a transformer bank is used to deliver power to more than one entity (that is, a joint use transformer bank), no-load iron losses are adjusted by the transformer percent use. This percent use is determined by dividing a negotiated contract kW load (*Contract kW*) at a negotiated power factor (*% Power Factor*) by the maximum available kVA from the transformer bank (*Max. Available kVA*).

$$\text{Percent Use} = \frac{\text{Contract kW} / \% \text{ Power Factor}}{\text{Max. Available kVa}}$$

Switched Lines

Line loss correction for radial lines which are switched, must be based on a negotiated average resistance based on the operating characteristics.

Transformer Load Tap Changer

Transformers equipped with a load tap changer (i.e., which has the capability to change transformer voltage tap positions or settings under Load) for regulating voltage, must have the corrections calculated at the median tap voltage. Differences in the corrections must be minimal and must even out over time as the bank operates above and below the median tap voltage.

C5 Worksheets

An example of a Transformer and Line Loss Correction Worksheet used to illustrate how the performance of the above calculations can be documented is available on the CAISO Website at:

<http://www.caiso.com/docs/2005/10/01/2005100119040822976.html>

Section D. Instrument Transformer Ratio and Cable Loss Correction Factors

D1 Background

All current transformers (CTs) and voltage transformers (VTs) (collectively, instrument transformers) have inherent errors due to their design and the physical properties of the materials used in their construction. These errors are manifested as a magnitude and phase angle difference between the "ideal" nameplate ratio and the waveform actually present on the secondary of the transformer. The terms used to denote these errors are Ratio Correction Factor (RCF) and Phase Angle Correction Factor (PACF).

The burden (load) connected to instrument transformer secondaries has an effect on the RCF and PACF of the units. All wiring and instrumentation of any kind is part of the burden. On a CT, the burden is designated in ohms and is represented by a number ranging from B-0.1 through B-1.8. On a VT, burden is measured in volt-amps and indicated by an alpha character, such as W, X, M, Y, Z or ZZ. The magnitude of these burdens must be known and kept within specified limits or additional errors occur in the metering.

Significant impedance in the leads between the VTs and the meter can be another source of error, where a voltage drop in the leads is caused by the load of the meter and any other connected devices between the VTs and the meter. Conductors which are too small or too long can cause metering error.

D2 Correction when the Burden Rating is exceeded

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet minimum CAISO accuracy requirements, then one of the actions listed below must be taken:

- i. The preferred action is to correct the problem by either replacing the instrument transformer(s) with higher burden rated revenue class units or reducing the burden on the circuit to comply with the name plate of existing instrument transformer(s).
- ii. An acceptable action is to apply CAISO approved correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The CAISO Metered Entity is responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meter to adjust for inaccuracies in the metering circuit. CAISO approved algorithms and spreadsheets for calculating correction factors are included in this Part.

D3 CT Ratio Correction Factor

Current transformers are usually tested by the manufacturer for the value of RCF and phase angle at both 5 and 0.5 amp secondary currents. The values for each CT in an installation would be averaged together to determine the CT Ratio Correction Factor (RCFI) and CT Phase Angle (b). If the current transformers used are revenue metering with an accuracy class of 0.3

% and are operated at or below their rated burden, then the correction factors may be disregarded.

D4 VT Ratio Correction Factor

Voltage transformers are usually tested by the manufacturer for the value of RCF and phase angle at rated voltage. The values for each VT in an installation would be averaged together to determine the VT Ratio Correction Factor (RCFE) and VT Phase Angle (g). If the voltage transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

D5 Cable Loss Correction Factor

The secondary voltage cables at an installation can be tested to determine the losses and phase angle of each. These values would then be averaged together to get the Cable Loss Correction Factor (CLCF) and the Phase Angle (a) for the installation. If the calculated connected burden of each phase do not exceed the VT burden rating, then the correction factors may be disregarded.

D6 Final Correction Factor

The PACF for an installation is determined by the following formula:

$$PACF = \frac{\cos(Q + b - a - g)}{\cos Q}$$

Where $\cos Q$ is the secondary apparent power factor.

The Final Correction Factor (FCF) can then be determined as follows:

$$FCF = RCFI * RCFE * CLCF * PACF$$

The Percent Error is the amount of error caused by the instrument transformers and cable loss, it is calculated as follows:

$$\text{Percent Error} = (1 - FCF) * (100)$$

The Percent Meter Adjustment is the adjustment to the meter required to compensate for the Percent Error, it is calculated as follows:

$$\text{Percent Adjustment Factor} = (FCF - 1) * (100)$$

The FCF is applied to the calibration of the meter, usually through adjustment of the calibration potentiometer or through a change in the programmed calibration values. After an adjustment to the meter is made, the meter should be tested at all test points to show that the meter is within calibration limits with the calibration values applied. A FCF which results in a correction of less than 0.6% can be disregarded since this is less than the required combined accuracy of

the instrument transformers. However, if any correction factor (full load, light load or power factor) results in a correction of more than 0.6%, they should all be applied.

D7 Applications

Typical Installation

The preferred meter installation would utilize revenue metering class instrument transformers (0.3 %) operated at or below rated burden. If this is not the case, one or more of the following actions may be used to correct the problem:

- Replace instrument transformers with higher burden rated units.
- Reduce the burden on the circuit to comply with the existing rated burden.
- Apply correction factors to the meter to compensate for inaccuracies.

Paralleling CTs

In normal revenue metering, current transformers would not be paralleled, but there are some applications where paralleling is done because the cost of the installation is reduced and the possibility of reduced meter accuracy is acceptable. A typical installation of this type would be to meter the net output of a generating station on a single meter rather than metering gross generator output and auxiliary power separately. In these type of installations additional rules apply:

All of the transformers must have the same nominal ratio regardless of the ratings of the circuits in which they are connected.

All transformers which have their secondaries paralleled must be connected in the same phase of the primary circuits.

The secondaries must be paralleled at the meter and not at the current transformers.

There should only be one ground on the secondaries of all transformers. This should be at their common point at the meter. Each utility may use their established grounding procedures.

Modern current transformers with low exciting currents and, therefore, little shunting effect when one or more current transformers are "floating" at no load should be used. Three or more "floating" current transformers might have an effect that should be investigated.

The secondary circuits must be so designed that the maximum possible burden on any transformer does not exceed its rating. The burden should be kept as low as possible as its effects are increased in direct proportion to the square of the total secondary current.

A common voltage and frequency must be available for the meter.

If adjustments are made at the meter to compensate for ratio and phase angle errors, the ratio and phase angle error corrections used must represent the entire combination of transformers as a unit.

The watt-hour meter must be able to carry, without overload errors, the combined currents from all the transformers to which it is connected.

While servicing meters and equipment on parallel CT secondaries, all CTs must be by-passed (shorted). When work is completed all bypasses must be removed.

D8 Worksheets

An example of an Instrument Transformer Ratio and Cable Loss Correction Factors Worksheet used to illustrate how the performance of the above calculations can be documented is available on the CAISO Website at:

<http://www.caiso.com/docs/2005/10/01/2005100119040822976.html>

Section E. Distribution Compensation Factor (DCF)

E1 Overview

A Distribution Compensation Factor (DCF) is the term used in quantifying the effect a CAISO Metered Entity generation has to the distribution facilities to which it is electrically connected to and through which it must pass its registered energy delivery to the CAISO Point of Receipt (POR).

E2 Determination of Distribution Compensation Factor (DCF)

The Distribution Compensation Factor must be based on an engineering study that is not in conflict with any Tariff or Interconnection Agreements entered into between the CAISO Metered Entity and the UDC/Distribution Provider for which they are an Interconnection Customer. The engineering study must be an analysis of the effect the delivery of energy has on the distribution system to which it is interconnected from the CAISO metered entities generator. The analysis provides the accounting for any losses or credits attributed to delivery of the energy into that distribution system at that point of interconnection.

The CAISO will recognize an engineering study found in or supporting a Distribution System interconnection agreement or Distribution System access tariff or agreement as a valid, independent study for purposes of determining the Distribution Compensation Factor.

In the absence of an engineering study, the CAISO will accept a default Distribution Compensation Factor of 1.0.

E3 Application of Distribution Compensation Factor (DCF)

When a CAISO Metered Entity is connected to a Utility Distribution Company's (UDC)/Distribution Provider Distribution System, an approved Distribution Compensation Factor must be determined and must be programmed into the meter to reflect the point of delivery at the CAISO Controlled Grid.

Agreement of the Distribution Compensation Factor by all parties will be a pre-condition to CAISO meter certification.

E4 Engineering Study for Distribution Compensation Factor (DCF) Guideline

The Engineering study should provide the following:

- Methodology of how DCF, loss or credit, was derived.
- Detailed calculation on overall and system component losses.
- Diagrams and power flows overall system including the point of interconnects.
- Calculated sub-transmission energy loss multiplier and loss adjustments
- Executive summary of the results including approved DCF.

Attachment C

CAISO Authorized Inspector Initial Site Verification and Meter Test Procedures

Attachment C: CAISO Authorized Inspector Initial Site Verification and Meter Test procedures

The intent of the site verification is to verify the metering circuit meets CAISO criteria prior to issuance of a CAISO metering certification. The purpose of this site verification process is to identify the duties of the person that will carry out the verification process for initial transformer rated CAISO Metering sites. The person completing this procedure must have a working knowledge of the instrument transformers, meters, local data server, and other associated metering equipment as well as being knowledgeable of CAISO certification guidelines.

C1. Instrument Transformer Verification

In all cases, if the current transformers or voltage transformers (CT/VT) are not accessible due to energized components or extensive disassembly is required that may impact plant availability, the CAISO Authorized Inspector notes the unavailability and requests the owner to identify a scheduled outage when the current transformer nameplate may be accessed safely.

C1.1 Name Plate Accuracy (5)

The CAISO Authorized Inspector visually inspects the primary connections of the current transformers and voltage transformers, then reads and records all the current transformer and voltage transformer nameplate data on the Site Verification Data Sheet. The nameplate data should include the following information.

- Manufacturer
- Serial number
- Voltage class
- Type
- Instrument Transformer ratios
- Burden rating
- Rating Factor
- BIL

- ANSI Accuracy Class

The CT should comply with ANSI 0.3 Accuracy Class for metering current transformers for B0.1 through B1.8 and the VT for X through ZZ. CAISO approved correction factor algorithms are allowed to compensate for less than + - 0.3% accuracy.

C1.2 Phase and Polarity checks

CAISO Authorized Inspector verifies that the polarity mark on all CT/VT follow the same convention (i.e. all polarity marks connected using the same convention, e.g., facing the CAISO grid). If there is more than one primary conductor passing through the CT/VT, then the phasing must be verified.

C1.3 Ratio Check

CAISO Authorized Inspector verifies that the stated CT/VT ratio matches the manufacturer's nameplate ratio. Where it is determined that the ratio is greater than + - 0.3% or ratio accuracy cannot be verified, a ratio test is required.

C1.4 Burden Check

The calculated or measured burden from all the equipment in the CT/VT circuit, including the meter(s), should be less than the CT/VT burden designated on the nameplate (reference ANSI Standard Burdens for instrument transformers).

C1.5 Transformer Correction Factor

If a transformer correction factor is applied to the meter, the CAISO Authorized Inspector reviews the CT/VT data (ratio and phase angle test at the specified burdens at full load) and the calculations (TCF¹⁰ at actual applied burden) provided by the owner to verify the instrument transformers meet the 0.3 Accuracy Class requirements.

C2. Metering Service Verification

The purpose of the metering service verification is to verify the metering installation is wired and operating properly.

¹⁰ Transformer Correction Factor

The CAISO Authorized Inspector records the service information on the Site Verification Sheet. The information includes the following:

- Point of Receipt to the CAISO Controlled Grid and Service Voltage,
- Power Transformer Rating
- Type of Service (3W Delta, 4W Wye or single phase, etc).

C2.1 Recording at Meter Test Switch

CAISO Authorized Inspector reads and records the voltage and current at the meter test switch. Record the date and time from the revenue meter. Isolate at the test switch and remove the revenue meter. Install and program the solid-state test meter for the appropriate service type.

C2.2 Recording Magnitude and Phase Angles

CAISO Authorized Inspector reads and records the magnitude and phase angles for each of the phase voltages and currents at the meter test switch even if the meter is not capable of producing angles.

C2.3 Required Method of Reading and Recording Voltage, Current and Phase Angles

C2.3.1 Preferred method for reading and recording voltage, current and all phase angles is to utilize the diagnostic capability of the meter that displays the necessary quantities.

C2.3.2 Read and record all current, voltage and phase angles readings on the Site Verification Data sheet. Also, complete the vector diagram to indicate the present phase relationships. Check for diagnostic errors.

C2.3.3 Check for diagnostic meter errors. If errors occur, analyze the site to correct error. Indicate on the remarks section of the Site Verification Data Sheet that a diagnostic meter error was detected.

C2.3.4 Complete the vector diagram with the recorded information. Compare the vector diagram with the given unity vector diagram found on the borders of the Site Verification Data sheet. Remember that the given vector diagrams are at the unit power factor, so the site vector diagram are shifted by a given angle.

C2.4 Accuracy Test

When possible, the meter accuracy testing must be performed when the unit is offline. If the meter accuracy test is performed when the unit is online it is prudent that the CAISO Authorized Inspector monitor the generation output using other plant instrumentation or have the plant operator maintain the generation at constant output.

C2.5 Instantaneous Demand

CAISO Authorized Inspector compares the instantaneous demand from the test meter to the instantaneous demand from the revenue meter and indicates the results on the Site Verification Data Sheet

C3. Revenue Meter

Upon successful completion of the Instrument Transformer Verification and the Metering Service Verification, the CAISO Authorized Inspector either performs or witnesses a test of the Revenue meter. The recommended practice is to test the meter in place using a CAISO approved watt-hour/var-hour standard and load box. The accuracy test should be performed in the test mode to prevent the registration of test data in the meter. Before taking the meter out of service, the CAISO Authorized Inspector verifies with CAISO Meter Engineering that all clearances and permits are in effect. The CAISO Authorized Inspector records the time the meter was taken out of service, the output level of the generator, if on-line, and the time that the meter was placed back in service. All of the following information is recorded on the Site Verification Data Sheet.

C3.1 Accuracy Test

CAISO Authorized Inspector either performs or witnesses the performance of a calibration test on the revenue meter for watt-hour and var-hour function for both directions of energy flow (delivered/received). Tests should be performed with and without compensation applied to get a true test of the metered site. Utilize a CAISO approved test set to perform the calibration test.

C3.2 Transformer and Line Loss Compensation Settings & Instrument Transformer Correction Factors

The Transformer and Line Loss Correction Factors compensation values, in addition to the correction factors from the meter are compared to the values found in the owner's documentation for the specific location. If the values

differ, the CAISO Authorized Inspector makes a note in the remarks section of the Site Verification Data Sheet.

C3.2 Distribution Compensation Factors

The Distribution Compensation Factors compensation values are compared to the values found in the owner's documentation for the specific location and those obtained by the CAISO. If the values differ, the CAISO Authorized Inspector makes a note in the remarks section of the Site Verification Data Sheet.

C3.3 Program and Input/Output Data check

The CAISO Authorized Inspector uses a laptop to verify correct programming (program ID) and programming constants for the revenue meter. The CAISO Authorized Inspector also verifies the proper operation of the KWh data output with a volt-ohm meter, if the output is being utilized.

C4. Communications Circuit Test

The purpose of this test is to verify that the CAISO RMDAPS system can communicate with the revenue meter. The communication circuit is typically either via a Frame Relay, ISDN, 56k digital circuit or switched phone circuit, etc.

CAISO Authorized Inspector requests the CAISO RMDAPS call the specific location and verify that the meter communicates. If the communication has not been installed, the CAISO Authorized Inspector uses a laptop or other test equipment to verify that the RS-232 ports of the meters are operational. Simulate an event that is programmed into the meter (such as power failure or threshold limit) and verify that the meter records and stores that event when polled by CAISO RMDAPS.

Attachment D

CAISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES FOR REVENUE QUALITY METER DATA (RQMD)

Attachment D: CAISO Data Validation, Estimation and Editing Procedures for Revenue Quality Meter Data (RQMD)

This procedure provides an overview of the process CAISO utilizes to VEE Meter Data received from CAISO Metered Entities and, where an exemption applies, Meter Data received from Scheduling Coordinators for Scheduling Coordinator Metered Entities.

D1 Timing of Validation

Meter Data is remotely retrieved from CAISO Metered Entities by RMDAPS on a daily basis. Validation is performed on the new Meter Data as it is retrieved from the meter in order to detect:

- Missing data
- Data that could be invalid based upon status information returned from the meter
- Meter hardware or communication failure

Additional validation is performed on an as needed basis to verify data against Load patterns, Backup Meters, Schedules, SQMDS load interval data and data obtained from SCADA.

D2 Data Validation Conditions of Metering/Communications Hardware

RMDAPS detects the following conditions so that erroneous data is not used for Settlement or billing purposes.

Validation detects the following metering/communication hardware failures:

- Meter hardware/firmware failures
- Communication errors
- Data which is recorded during meter tests
- Mismatches between the meter configuration and host system master files
- Meter changeouts (including changing CT/VT ratios)
- Gaps in data
- Overflow of data within an interval

- ROM/RAM errors reported by the meter
- Alarms/phase errors reported by the meter

D3 Validation Criteria

Validation criteria are defined by CAISO for each channel of SQMDS load interval data (kW/kVAR/kVa/Volts, etc.) depending on the Load characteristics for each meter location and the type of data being recorded.

For Loads that do not change significantly over time or change in a predictable manner, percentage changes between intervals is used.

For Loads that switch from no-Load to Load and for reactive power where capacitors are switched to control power factors, validation is based upon historical data for that meter location. If no historical data is available, data such as the rating of transformers or the maximum output from a Generating Unit is used to set maximum limits on interval data.

Validation is based upon reasonable criteria that can detect both hardware and operational problems with a high degree of confidence but is set so as to avoid unnecessary rejection of data.

D4 Validation of Stated Criteria

Data validation is performed only for the validation criteria that have been entered for each meter channel of data. For example, the number of intervals of zero Energy recorded by the meter for the channel indicated is validated only when a non-zero value is entered for these criteria.

Additional validation can be performed on a daily basis to verify data which is based upon load patterns, comparisons to Backup Meters, schedules, SQMDS load profiles or data obtained from SCADA.

D5 Validation Failure

Data that fails validation is flagged with the reason for the failure, where applicable. Data that fails checks is identified so that manual intervention can be used to estimate the correct values in order to edit the data or to manually accept the data.

D6 Validation Criteria

D6.1 Time of Application of Criteria

<u>Validation Criteria</u>	<u>Interval</u>
Meter Data vs. Recorder Data (Energy Tolerance)	Yes
Intervals Found vs. Intervals Expected	Yes
Time Tolerance Between RMDAPS and Meter	Yes
Power Outage Intervals	Yes
Missing Intervals (Gaps in Data)	Yes
High/Low Limit Check On Interval Demand	Yes
High/Low Limit Check on Energy	Yes
CRC/ROM/RAM Checksum Error	Yes
Meter Clock Error	Yes
Hardware Reset Occurred	Yes
Watchdog Timeout	Yes
Time Reset Occurred	Yes
Data Overflow In Interval	Yes
Parity Error (Reported by Meter)	Yes
Alarms (From Meter)	Yes
Load Factor Limit	Yes
Power Factor Limit	Yes
Main vs. Backup Meter Tolerance	Yes
Actual vs. Schedule Profile	Yes
Actual vs. SCADA Data	Yes
Comparison of Current Day to Previous Day	Yes
Percent Change Between Intervals	Yes

D6.2 Meter Data vs. Recorder Data (Energy Tolerance)

D6.2.1 Meter Readings

Meter readings are obtained from CAISO approved meters on a daily basis in order to validate interval Energy measurements. This Energy tolerance check is used to detect meter changeouts or changes in metering CT/VT ratios that have not been reflected in the RMDAPS

master files (meter configuration files). A “tolerance type” parameter is set in the RMDAPS system parameter to define the type of check to be performed.

The types of check that can be used include the following:

ID	Term	Description
M	Multiplier	Allows a percentage of the meter multiplier difference between the meter reading the recorded interval total energy.
P	Percent	Allows a percentage of the metered total energy difference between the metered total energy and the recorded total energy. The percent of allowed difference is defined by CAISO on an individual meter channel basis.
Q	Same as percent	Based on 30 days of data. If the data relates to a period less than 30 days then the total usage is projected to 30 days as follows: Projected Usage=Total Usage*(30/Total Days)
D	Dual Check	Percent Method (P) is the primary check. If it fails, then the Multiplier Method (M) is used.
E	Dual Method	Percent Method (Q) is the primary check. If it fails, then the Multiplier Method (M) is used.
N	None	No tolerance check

D6.2.2 Intervals Found vs. Intervals Expected

RMDAPS calculates the expected number of time intervals between the start and stop time of the SQMDS Load Profile data file and compare that number against the actual number of time intervals found in the RMDAPS data file. The calculation used to determine the expected number of time intervals takes into account the size or duration of the actual time intervals for the particular meter/data file (e.g., 5 min, 15 min, 30 min and 60-min interval sizes).

D6.2.3 Time Tolerance Between RMDAPS and Meter

When RMDAPS retrieves data from a meter, the RMDAPS workstation clock is compared against the meter’s clock. RMDAPS is configured to automatically update the meter closes within certain tolerances, limits and rules including:

- A time tolerance parameter (in seconds) that indicates the allowable difference between the RMDAPS workstation clock and the meter clock (if the meter clock is within that parameter, RMDAPS does not update the meter clock)
- An upper limit for auto timeset that is the maximum number of minutes a meter can be out of the time tolerance before RMDAPS performs an auto timeset

- RMDAPS does not perform auto timesets across interval boundaries
- The auto timeset feature supports DST changes and time zone differences. Since all CAISO Metered Entity's meters that are polled by RMDAPS are set to Standard Time, this rule does not generally apply

D6.2.4 Number of Power Outage Intervals

CAISO approved meters record a time stamped event for each occurrence of a loss of AC power and a restoration of AC power. During the Meter Data retrieval process, RMDAPS flags each RMDAPS interval between occurrences of AC power loss and AC power restoration with a power outage status bit.

D6.2.5 Missing Intervals (Gap in Data)

The RMDAPS validation process compares the stop and start times of two consecutive pulse data files for a meter and reports if a missing interval/gap exists.

D6.2.6 High/Low Limit Check on Interval Demand and Energy

The RMDAPS validation process compares the Demand and Energy High/Low Limits entered by the RMDAPS operator on a meter channel basis in the RMDAPS meter channel table against the actual values collected from the meter. This comparison is performed on an interval-by-interval basis. If the actual values are either less than the Low Limit or greater than the High Limit, then the RMDAPS validation process fails.

D6.2.7 CRC/ROM/RAM Checksum Error

This general meter hardware error condition can occur during an internal status check or an internal read/write function within the meter. This error code is not standard on some meters (reference must be made to the meter's user manual). When available, this internal status information is collected during the RMDAPS Meter Data retrieval process and stored for review/reporting purposes.

D6.2.8 Meter Clock Error

This meter hardware error condition can occur whenever an internal meter hardware clock error results in an invalid time, day, month, year, etc. This error code is not standard on some meters (reference must be made to the meter's user manual). When available this interval status information is collected during the RMDAPS Meter Data retrieval process and stored for review/reporting purposes.

D6.2.9 Hardware Reset Occurred

This meter hardware error condition occurs whenever an internal meter hardware reset occurs. This error code is not standard on some meters (reference must be made to the meter's user manual). When available this interval status information is collected during the RMDAPS Meter Data retrieval process and stored for review/reporting purposes.

D6.2.10 Watchdog Timeout

This error code is not standard on some meters (reference must be made to the meter's user manual). When available, this feature watches for meter inactivity, indicating a possible meter failure.

D6.2.11 Time Reset Occurred

This is a meter error code that indicates that the meter time has been reset. See Time Tolerance Between RMDAPS and Meter.

D6.2.12 Data Overflow in Interval

This error code occurs when the amount of data in an interval exceeds the memory capabilities of the meter to store the data. This alerts RMDAPS that there is corrupt data for the interval.

D6.2.13 Parity Error (Reported by Meter)

Parity error is another indicator of corrupted data.

D6.2.14 Alarms (From Meter)

CAISO RMDAPS operator evaluates all meter alarms to determine if the alarm condition creates data integrity problems that need to be investigated.

D6.2.15 Load Factor Limit

The RMDAPS validation process can compare the daily Load Factor to the limit entered by the RMDAPS operator. RMDAPS prompts the operator to investigate data integrity if the limit is out of tolerance.

D6.2.16 Power Factor Limit

The RMDAPS validation process can compare the actual Power Factor to the limit entered by the RMDAPS operator. RMDAPS prompts the operator to investigate if the limit is out of tolerance.

D6.2.17 Main vs. Backup Meter Tolerance

The main and check Backup Meters can be configured in RMDAPS to be compared on a channel by channel basis to the Backup Meter ID, channel number, percent tolerance allowance and the type of check. Interval or daily Meter Data is entered into the corresponding main meter RMDAPS meter channel table record. This information remains constant unless:

- A meter changeout occurs at the site
- The percent tolerance allowance needs adjusting
- The type of check is switched

If the percentage difference between the main channel interval Demand and the check channel interval Demand exceeds the Percent Tolerance allowed, the RMDAPS validation fails. If, after applying this validation test, the percentage difference between the main channel total Energy and the check channel total Energy for each Trading Day exceeds the allowed percentage, the RMDAPS validation fails. In both cases, if the percentage difference is less than the Percent Tolerance allowed, the RMDAPS validation is accepted.

D6.2.18 Actual vs. Schedule Profile

Data can be compared on an interval by interval basis like main meter vs. Backup Meter.

D6.2.19 Actual vs. SCADA Data

Data can be compared on an interval by interval basis like main meter vs. Backup Meter.

D6.2.20 Comparison of Current Day To Previous Day

The RMDAPS validation process compares the last complete days' Demand and Energy in the validation time period to one of the following parameters configured by the RMDAPS operator:

- Previous day
- Same day last week
- Same day last month

Validation failure

If the percentage difference between the Demand and Energy exceeds the tolerance setup in the RMDAPS validation parameters, the data subjected to the validation process fails.

D6.2.21 Percent Change Between Intervals

The RMDAPS validation process uses the Interval Percent Change Tolerance set by the RMDAPS operator on a meter channel basis in the RMDAPS meter channel table to compare the percentage change in the pulses for the channel between two consecutive intervals. If the percent change exceeds the Interval Percent Change Tolerance set for that channel, the RMDAPS validation process fails.

D7 Data Estimation Criteria

When interval data is missing due to there not being any response from the meter or the meter reports it as missing, RMDAPS supplies estimated data for the missing intervals based on the guidelines discussed below.

If a certified Backup Meter is available and that data is valid, the data from the Backup Meter is used to replace the invalid or missing data from the main meter. When reading meters on a frequency basis, the point-to-point linear interpolation method is used to estimate the current interval(s) of data. This method is normally only used when estimating one hour or less of contiguous missing interval data when the previous and next intervals are actual values from the meter. If data is missing for an extended timer period, historical data, schedules, load profiles or data obtained from SCADA can be used as the reference data so that data can be matched to time of day and day of week.

D7.1 Data Estimation Methods

The following data estimation methods are configurable by the RMDAPS operator on a meter-by-meter basis. The algorithms for each method are described below in order of precedence as implemented by the RMDAPS automatic estimation application software. The SQMDS operators can alter this order by simply not activating a certain method. In addition, the RMDAPS operator can manually select each data estimation method at any time during the data analysis process.

D7.1.1 Main vs. Backup Meter

The global primary and Backup Meters can be configured in the RMDAPS meter channel table to be compared on a channel-by-channel basis. The Backup Meter ID and channel number must be entered into the corresponding primary meter RMDAPS meter channel table record. This information remains constant unless a meter changeout at the site occurs. During the RMDAPS automatic estimation process, if missing data is encountered and actual values from a certified Backup Meter are available, the values for the corresponding intervals from that Backup Meter is substituted into the data file for the primary meter. All copied intervals are tagged as an edited interval. In order for actual values from the Backup Meter to be deemed

acceptable for use in the data file that passed the validation criteria preferred to earlier in this attachment and no error codes or alarms can be set on the interval values. Meter Data from Backup Meters is only used where Meter Data is not available from the primary meter.

D7.1.2 Point-to-Point Interpolation

When reading meters on a frequency basis, the Point-to-Point Linear Interpolation Algorithm described below can be used to estimate the missing intervals of data. This method is normally only used to estimate a maximum of one hour of contiguous missing interval data when the previous and next intervals are actual values from the meter. Even though this method is not normally used above that maximum of one hour, the RMDAPS allows this maximum threshold to be set by the RMDAPS operator on a meter-by-meter basis. The same rules for defining acceptable actual values apply as detailed in main vs. Backup Meter description above. All estimated intervals are tagged as an edited interval.

Point-to-Point Linear Interpolation Algorithm

$$\text{Estimated Interval} = (\text{Next Actual} - \text{Previous Actual Interval}) / (\text{Number of Missing Intervals} + 1) + \text{Previous Actual Interval}$$

D7.1.3 Historical Data Estimation

Historical data estimation is the process of replacing missing or corrupt interval data in the RMDAPS data files. The data is replaced using historical data as a reference. There are two basic requirements when estimating data to be inserted or replaced:

- The amount of data to add or replace
- The shape or contour of the data over the time span requested

D7.1.4 Estimation Parameters

The following estimation parameters are required on a per meter basis:

Auto Plug (Y/N)	Controls the option to perform automatic estimation
Auto Plug Option (W/C/P/L)	Indicates where to get the reference data used in the estimation process: W - use the previous week as the reference data (all data for the week must be present). C - use the current month as reference data. P - use the previous month as reference data. L - use the current month of last year as reference data.
Reference ID	ID from which the reference data is retrieved. The

	contour of the data is determined from this ID. The Reference ID can be the same as the meter ID (i.e. use historical data from the same meter) or a different Reference ID.
Auto Plug Missing Days Limit	Verifies that the number of missing days of data is less than the missing day limit in order to invoke automatic estimation
Auto Plug Reference Data %	Identifies a percent adjustment for situations where there is a need to factor the reference data by a percent increase or decrease. If this value is set to "0", the adjustment is not performed.
Auto plug Power Outage	Indicates if intervals with a power outage status are to be estimated/replaced automatically.
Reference Tim Span	Identifies the reference time span for the historical data.

D7.1.5 Total Data

The estimation algorithm used depends on the total amount of data to be added or replaced and the shape of that data. The RMDAPS operator can give the total data or that can be calculated to balance the meter usage in the file. The shape of the data is defined with the use of the reference data.

D7.1.6 Reference Data

The reference data is based on the day of the week. All reference data is averaged and stored into a seven day table of values for each interval. The table includes a day's worth of intervals for each day of the week (Sunday-Saturday). When the shape of a day's data is needed, this weekly table is referenced. Two data tables are set up to use in the algorithm. One stores the number of times that an interval value is needed from there reference data, while the other table maps the interval value in the reference data to the correct data in the update file. The data from the reference must be scaled up or down to match the magnitude of the data needed for the update file. This is determined by comparing the data total from the reference file with the data needed for the update file. This ratio is used when getting reference data to use the update file.

D8 Editing

All estimated intervals are tagged as an edited interval in RMDAPS. The CAISO RMDAPS operator notifies the Metered Entity of the edited interval start and stop times, new value and technique used to estimate the data.

If estimation and editing is frequently required for the Meter Data received from a particularly metered entity, CAISO may require recertification and or facility maintenance or repair to correct the continued provision of erroneous or missing data.

Attachment E

**CAISO AUDIT OF CERTIFIED METERING
FACILITIES**

Attachment E: CAISO Audit of Certified Metering Facilities

CAISO representatives audit Metering Facilities to ensure revenue data reliability. CAISO audit of Metering Facilities is a SAS-70¹¹ Type II audit standard. Site audits involve mandatory visits to CAISO Metered Entity sites. CAISO Metered Entity meters include all meters designated as CAISO meters, regardless of their polled status.

- 1) CAISO requests a clearance to the Metering Facility in order to conduct a site audit.
- 2) CAISO conducts the mandatory audit by comparing values and information against data on file with the CAISO. CAISO Meter Engineer performs the following:
 - a) Record and compare seal numbers with the last site inspection or audit. Verify that CAISO approved seals are used where seals are required.
 - b) Compare the register constant, current and voltage ratios in the meter's program to ensure the integrity of the data
 - c) Verify the values that the meter uses to communicate the data to the CAISO RMDAPS system
 - d) Verify the password on polled meters
 - e) Change the password on non-polled meters
 - f) Perform meter time correction if the meter's time is off more than +/- (1) minute (time verification are made before a site visit and compared with the United States Naval Observatory and updated on the Meter Engineer's laptop).
 - g) Conduct comparison of the load and or the generation to verify the display, recorder files and the RMDAPS channel.
 - h) Affix a CAISO Revenue Metering audit sticker on all meters audited.
- 3) Meter Maintenance

¹¹ Statement on Auditing Standards No. 70

CAISO reports damaged meters, or meters requiring maintenance, and any other meter-related problem found during an audit to the Metering Facility contact.

4) Meter Site Security

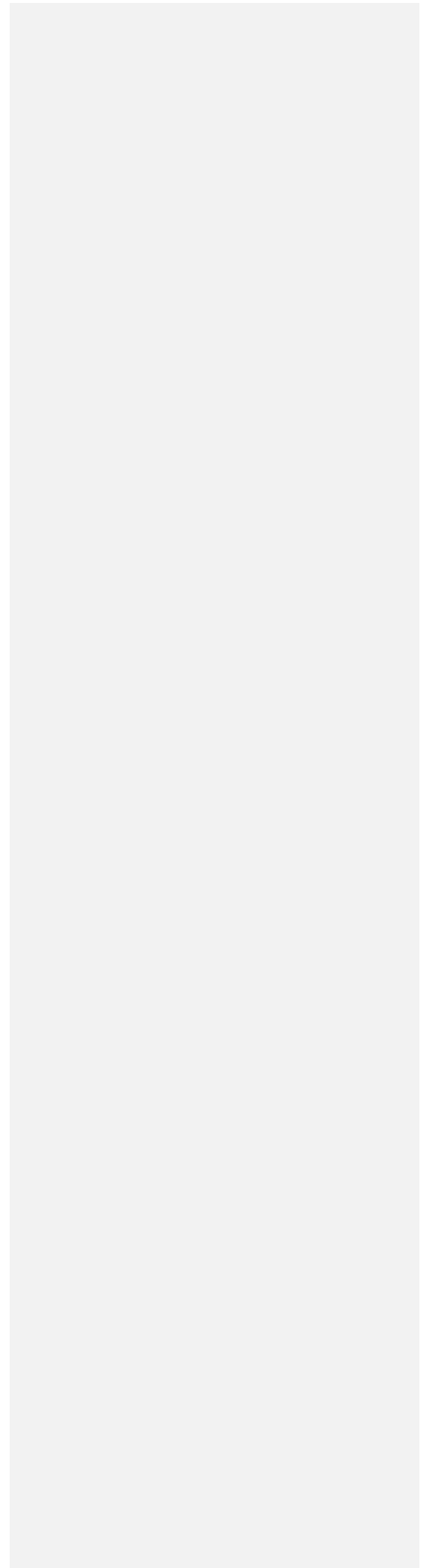
CAISO reports any revenue meter test switches or shorting switches for the current circuit and the voltage circuit (if one exist) found unsealed. CAISO ensures that the meter meets the meter site security requirements as detailed in section 5.1.4 of this BPM.

5) Audit Results

CAISO completes an internal Metering Site Audit Form and updates the Metering Facility file for each meter audited.

Attachment F

STATION POWER REALLOCATION EXAMPLE



Attachment F: Station Power Reallocation Example

The following is an example assuming a Netting Period of 10 time periods with a Station Power Portfolio including 3 sites all separated by CAISO Controlled Grid where each site has a Station Power Load meter and an on-site generating facility. For a calendar month with 30 days, there 4,320 time periods for a unit in a Station Power Portfolio (6 ten-minute intervals per hour * 24 hours* 30 days)

METER DATA REALLOCATION PROCESS																	
ASSIGNMENT OF REMOTE SELF-SUPPLY AND THIRD PARTY SUPPLY TO SITES AND TIME PERIODS																	
Netting Period in this example is 10 Time Periods																	
Time Period																	
Sites: Gen/Load	1	2	3	4	5	6	7	8	9	10	(1) Monthly Net Generation	(2) Total Station Power Draws	(3) Rank for Allocation	(4) Allocation of Third Party Supply	(5) Remote Self-Supply	Sum of Net Load	
Site 1 Ch 1	1.3	2.4	2.1	1.9	2.3	2.4	2.0	2.0	2.0	2.0	13.6	20.4	NA	0	0	19.1	
Site 1 Ch 4	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Site 1 Net Load	0.0	2.4	2.1	1.9	2.3	2.4	2.0	2.0	2.0	2.0							
Site 2 Ch 1	1.0	2.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	-21.0	23.0	1	21	0	22.0	
Site 2 Ch 4	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Site 2 Net Load	0.0	2.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0							
Site 3 Ch 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	-20.0	20.0	2	6.4	13.6	20.0	
Site 3 Ch 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0							
Site 3 Net Load	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0							
Portfolio	Total										-27.4	63.4		27.4	13.6	61.1	
(6) On-Site Self-Supply Load ID																	
Time																	
Period	1	2	3	4	5	6	7	8	9	10	Total						
Site 1	1.3	2.4	2.1	1.9	2.3	2.4	2.0	2.0	2.0	2.0	20.4	Meter Data Assumptions					
Site 2	1.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	2.0						
Site 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0						
											Total	22.4					
(7) Third Party Supply Load ID																	
Time																	
Period	1	2	3	4	5	6	7	8	9	10	Total						
Site 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0						
Site 2	0.0	1.9	2.9	1.9	1.9	2.9	2.9	1.9	1.9	2.9	21.0						
Site 3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	6.4						
											Total	27.4					
(8) Remote Self-Supply Load ID																	
Time																	
Period	1	2	3	4	5	6	7	8	9	10	Total						
Site 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0						
Site 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0						
Site 3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	13.6						
											Total	13.6					
Notes:																	
(1) Monthly Net Generation is Gross Generation less Gross Load over the Netting Period. If the value is positive for an individual site, then On-Site Self Supply is attributed to serving that site's Station Power load for the month. If the value for any individual site is negative, then Station Power load exceeded On-Site Self Supply in the Netting Period for each such site (i.e., a deficit in On-Site Self Supply existed). If the Total for the portfolio is positive, then Remote Self Supply is attributed to serving any deficits in On-Site Self Supply. To the extent that the Total for the portfolio is negative, then Third Party Supply has served Station Power in the portfolio.																	
(2) The Station Power Draw is net Station Power load when a unit is off line, or generating less than its Station Power load. Total Station Power Draws represent the total Station Power Load excluding the Station Power that is netted under Permitted Netting.																	
(3) When Third Party Supply is used, the magnitude of the Total Station Power Draws in the Netting Period is used to allocate Third Party Supply to each site. The site with the highest Total Station Power Draws will be allocated Third Party Supply until its negative Monthly Net Generation is fully served. If Third Party Supply remains to be allocated, then it is allocated to the site with the second highest Total Station Power Draws, and so on until the Third Party Supply is completely allocated.																	
(4) The result of the assignment of Third Party Supply to each site as described in Note 3 is shown here.																	
(5) Remote Self-Supply is attributed to serving any remaining Monthly Net Generation that is not assigned Third Party Supply as described in Note 3.																	
(6) When Monthly Net Generation for an individual site is positive, then all of Station Power load is recorded onto the On-Site Self-Supply Load ID for each period in the Netting Period. Zero load values should be recorded on that site's Remote Self-Supply and Third Party Self-Supply Load IDs.																	
(7) The amount of Third Party Supply assigned to each site is distributed pro rata to the time periods in which each such site had a Station Power Draw. The assignment to each time period is: (Station Power Draw in that time period / Total Station Power Draws for that Site) X Allocation of Third Party Supply to that site. The site/time period allocation is to be used for rebating the cost of wholesale power.																	
(8) Remote Self-Supply is assigned to each hour in the Netting Period as the difference between the Station Power load to be served and the amount of Third Party Supply assigned in that hour.																	

Attachment G

Proxy Demand Resource (PDR)

~~And Reliability Demand Response Resource (RDRR)~~

Baseline Calculation Example

Attachment G: PDR ~~and RDR~~ Baseline Calculation Example

The following is an example of a Baseline, Load Point Adjustment, PDR Energy Measurement and Default Load Adjustment applicable for both a PDR ~~and RDR~~ Resource. (NOTE: does not include RT UIE adjustment as it is not applicable for this DA award only example)

Baseline Calculation

Example: PDR Resource id PGEB_1_PDRC01 with following assumptions

- DA awards for Trade Dates 4/26/09 and 4/27/09 HE14
- DA award occurs in HE14 for TD 5/1/09
- No other event hours for 5/1/09
- Data used for calculating the Raw Baseline_{reh} = $(1 / (d)) * \sum_d \text{Load}_{rdh}$

Date	Type	Event	HE14
4/15/2009	WD	N	15.00
4/16/2009	WD	N	15.75
4/17/2009	WE	N	10.50
4/18/2009	WE	N	9.50
4/19/2009	WD	N	13.75
4/20/2009	WD	N	14.00
4/21/2009	WD	N	14.75
4/22/2009	WD	N	14.00
4/23/2009	WD	N	13.75
4/24/2009	WE	N	6.00
4/25/2009	WE	N	15.75
4/26/2009	WD	Y	14.80
4/27/2009	WD	Y	15.50
4/28/2009	WD	N	14.00
4/29/2009	WD	N	14.00
4/30/2009	WD	N	13.80

Date	MWH	Selection
4/15/2009	15.00	10
4/16/2009	15.75	9
4/19/2009	13.75	8
4/20/2009	14.00	7
4/21/2009	14.75	6
4/22/2009	14.00	5
4/23/2009	13.75	4
4/28/2009	14.00	3
4/29/2009	14.00	2
4/30/2009	13.80	1
10 Day Avg (Raw Baseline)	14.28	

Selection Criteria Type=WD
 Event=N
 Where WD = Week Day
 WE = Week End
 Event = Y if DA schedule, RT/AS dispatch or Outage

Load Point Adjustment

The following is an example for the load point adjustment calculation:

	Raw Baseline	Metered Load
HE 10	13	12
HE 11	13	11
HE 12	13.4	12.5
SUM	39.4	35.5

Load Point Adjustment (Morning Adjustment) =
 Max(.8, Min(1.2, sum load/sum raw baseline) =
 Max(.8, min(1.2, 35.5/39.4)) = .90

PDR Energy Measurement

Example: PDR Resource id PGEB_1_PDRC01 (continued)

- Assumptions:
 - DA award occurs in HE14 for TD 5/1/09
 - Real time adjustment not applicable since RT dispatch was not during the event hour
 - No other event hours for 5/1/09
 - HE 14 SQMD submitted for PDR Registration 1 underlying load = 11.90 MWH
 - Load Point Adjustment = *Morning Baseline Adjustment* = .90

Raw Baseline		Load Point Adjustment	=	Baseline	-	Metered Load	=	PDR Generation Measurement
14.28	x	0.90	=	12.85	-	11.90	=	0.95 MWH

Default Load Adjustment (DLA) Example: PDR Resource id PGEB_1_PDRC01 (continued)

- Assumptions:
 - Four PDR resources have event on TD 5/1/09 HE14

Effective Date	Registration	Resource	DRP	DRP's SC	LSE's SC	LSE Load Resource ID	Metered Load	10 day Avg Load	Morning Adjustment	Baseline	PDR Gen
4/1/09 - 5/31/09	Reg1	PGEB_1_PDRC01	DRP1	SC1	SC5	DLAP_PGAE_SC5	11.90	14.28	0.90	12.85	0.95
6/1/09 - 9/30/09	Reg2	PGEB_1_PDRC01	DRP1	SC1	SC5	DLAP_PGAE_SC5	n/a	n/a	n/a	n/a	n/a
5/1/09 - 5/1/2020	Reg5	PRMN_6_PDRC01	DRP2	SC1	SC9	DLAP_PGAE_SC9	9.00	10.80	0.94	10.15	1.15
4/1/09 - 9/1/09	Reg11	AMRG_1_PDRC01	DRP3	SC2	SC5	DLAP_PGAE_SC5	9.00	10.80	1.00	10.80	1.80
3/1/2009-3/1/2020	Reg13	ROSE_6_PDRC01	DRP3	SC3	SC2	DLAP_SCE1_SC2	7.00	8.40	1.02	8.57	1.57

Therefore, a DLA is calculated for 3 separate LSE's for PDR Generation in their DLAP

Default Load Adjustment (DLA)	
DLAP_PGAE_SC5	.95 + 1.80 = 2.75
DLAP_PGAE_SC9	1.15
DLAP_SCE1_SC2	1.57