BONNEVILLE
POWER ADMINISTRATION

Metering Application Guide
STD-DC-000005-00-03

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1 Intent

1. The purpose of this guide is to enable Bonneville Power Administration (BPA) to provide a single standard application guide for both BPA and customers for revenue, interchange, and generation integration metering. For interchange metering, installations will comply with current NERC Standards for Operating Interconnected Power Systems.

2. This guide covers the installation of revenue, interchange, or generation integration meters, in either customer or BPA sites, communications to such meters, use of outputs from such meters, current and potential transformer requirements for metering, and all associated ownership, maintenance and testing issues of such meters.

3. This guide applies to both new and revised metering installations.

4. This guide will be revised as technologies change.

5. This document is owned and maintained by the Remedial Action Scheme (RAS) and Data Systems Engineering Design group at BPA.

2 Definitions

ACB	Air circuit breaker
ACE	Area control error
AGC	Automatic generation control
ANSI Standard Accuracy (C57.13)	ANSI specifications call for 0.3% accuracy at 100% of load rating and 0.6% accuracy at 10% of rating. Operating below 10% of the CT Rating accuracy is undefined. Fortunately, most CTs perform much better than this, with 0.3% accuracy often extending down to 5% of CT Rating. But the ANSI standard by itself does not provide the 0.3% accuracy over the entire load range that BPA requires.
Area Control Error (ACE)	ACE is the instantaneous difference between net actual and scheduled interchange.
Automatic Generation Control (AGC)	AGC is a system that measure instantaneous load and interchange points and adjusts generation to follow load. Telemetered real time load signals (kW) are input to the AGC system.

Balancing Authority Area (formerly known as Load Control Area)	The electrical region within which a utility has the responsibility to balance load and generation while maintaining system voltages, frequency, generation reserves and meeting other mandated requirements. BPA performs these services for its customers that are inside the BPA balancing authority (or load control) area.
Basic Impulse Insulation Level (BIL)	Outdoor electrical distribution systems are subject to lightning surges. Even if the lightning strikes the line some distance from the transformer, voltage surges can travel down the line and into the transformer. High voltage switches and circuit breakers can also create similar voltage surges when they are opened and closed. Both types of surges have steep wave fronts and can be very damaging to electrical equipment. To minimize the effects of these surges, the electrical system is protected by lightning arresters, but they do not completely eliminate the surge from reaching the transformer. The Basic Impulse Level (BIL) of the transformer measures its ability to withstand these surges.
Burden	The burden in a CT metering circuit is essentially the amount of impedance (largely resistive) present. Typical burden ratings for CTs are B0.1, B0.2, B0.5, B1.0, B2.0 and B4.0. This means a CT with a burden rating of B0.2 can tolerate up to 0.2 Ω of impedance in the metering circuit before its output current is no longer a fixed ratio to the primary current. Items that contribute to the burden of a current measurement circuit are test switches, terminal blocks, meters and intermediate conductors. The most common source of excess burden in a current measurement circuit is the conductor between the meter and the CT. Often, substation meters are located significant distances from the meter cabinets and the excessive length of small gauge conductor creates a large resistance. This problem can be solved by using larger secondary conductors or locating the meter closer to the CTs.
CT	Current transformer
CT Burden Rating	The maximum secondary current circuit resistance, in Ohms, including wire leads and all connected equipment, at which the CT will maintain rated accuracy. The maximum standard burden rating normally available is B1.8, which is what BPA requires in BPA and in customer supplied CTs. Higher burden ratings will result in more “robust” CTs,

	better able to retain accuracy during challenging and varied conditions. This is why BPA specifies B1.8. The general design criterion for CTs is minimum burden, which increases accuracy. This may mean doubling up on conductors for long runs from the CT to the meter, or increasing conductor size, to minimize lead resistance.
CT Rating	The primary current at which the CT produces 5 A in the secondary circuit to the meters. For example, a CT with a rating of 1200 A would be expressed as 1200:5 ratio and would produce 5 A secondary current at a 1200 A primary current.
CTR	Current transformer ratio
CVT	Capacity voltage transformers
DATS	Dial automatic telephone switching
Direct-Service Industries (DSI)	Direct-Service Industries were large industrial customers served directly by BPA. As of October, 2006, BPA no longer markets power to DSIs.
EIDE	Electric Industry Data Exchange
EMI	Electro-magnetic interference
Extended Accuracy	Increased accuracy—usually 0.15% rather than the normal 0.3%—extends over most of or all of the range of the CT. Accuracy does not decrease as loads get smaller as allowed by ANSI specification C57.13. When extended accuracy is combined with extended range, CTs are available in some voltage classes that are 0.15% from 0.5% to 400% of CT Rating.
Extended Range	Extended Range is operating beyond the normal ANSI CT range of 10–100% of CT Rating. This increases the high and low range over which accuracy is maintained. Standard accuracy is extended to both the high end of CT rating (see Rating Factor) and to the very low end of the load range, often to 0.5% of CT rating. For a 1200:5 CT, low end would be extended to 6 A primary current (1200 A $\times$ 0.005 = 6 A).
Ferroresonance	Ferroresonance is the occurrence of an unstable high voltage, typically on three phase electrical systems, which only occurs under specific conditions. The nature of the overvoltage can cause the failure of equipment. Ferroresonance occurs when an unloaded 3-phase system consisting of an inductive and a capacitive component is interrupted by single phase means.

Generation Integration Metering	Generation Integration Metering is used where a generation facility in the BPA Balancing Area connects into the BPA transmission system, either directly or through transmission facilities owned by a third party. See Section 7 for more details
Ground Potential Rise (GPR)	Ground Potential Rise (GPR) is the product of ground electrode impedance, referenced to remote earth, and the current that flows through that electrode impedance. That is, $$E = I \times Z$$ where I is the fault or surge current, Z is the ground grid impedance (AC resistance), and E is the resulting Potential or Voltage rise. At electric power stations and power line transmission poles and towers, when a power system ground fault or lightning strike occurs, all or some of the current returns via the earth through the grounding electrode and produces a potential difference between the grounding electrode and remote earth. This potential difference is the ground potential rise (GPR). The fault current may be symmetrical or may have some degree of asymmetry, depending on such factors as voltage phase angle at fault initiation, location of the fault, impedance to ground and other power system characteristics. The impedance to ground depends primarily on the geometry of the grounding electrode, the connections to it, and the resistivity of the soil in the vicinity of the site. GPR is not an issue with Three Phase or Phase-to-Phase ground faults since there is no ground current flow, thus no potential rise possible. In both of these cases, the fault current flows through the conductors. For Ground mat Rise studies in substations, BPA uses the “GPR with DC offset” value to design appropriate telephone isolation/protection needs. **Note**: GPR with DC offset $\approx 2 \times$ GPR Peak Voltage. (Reference: IEEE Standard 487-2007; see Appendix A).
IME	Interchange meter error
Instrument Transformers	*Instrument Transformers* is a generic term which refers to either current transformer (CT) or voltage/potential transformer (VT/PT) as compared to power transformers. Instrument transformers reduce the line current and voltage being provided to the customer’s load to safe

	levels for input to solid state meters.
Interchange Metering	Interchange metering measures power crossing the boundary between BPA's load control area and the load control area of another balancing authority. Hourly kWh pulses and continuous kW analog data are required for interchange metering installations to verify that hourly power schedules across the boundary are met. Interchange Metering also includes utilizing analog values for AGC (automatic generation control).
Intertie Metering	"Intertie" is a generic term in the electrical industry for a connection between two large utilities or regions such as in reference to the North–South Intertie to California. "Tie Lines" are the actual physical connections to make this happen, and metering on a tie line could be called intertie metering. This is often a connection between what are called "balancing authorities areas."
IP	Internet Protocol
Isolation	Analog outputs or pulses repeated to customers will be physically and electrically isolated from BPA equipment.
MDM	Meter data management
Meter Inputs and Outputs:	Three-phase meters on the BPA system may be configured to produce two different kinds of external outputs: integrated kWh/ kVARh pulses and analog instantaneous signals. Internal meter registers can be accessed through a serial port. A pulse is an event produced inside the meter (like a contact opening and closing) that can be monitored and recorded by an external device such as a remote demand recorder. The meter may be scaled so that each pulse produced represents a certain number of Watt-hours (Wh) or VAR-hours (VARh). Pulses are produced by the meter when the set amounts of Wh or VARh are accumulated. The integrated pulses are summed and stored on an hourly basis by either an external recorder or in the registers of newer style meters. Analog milliamp (mA) output signals are proportional to the instantaneous load Watt and VAR values and will continuously change with the instantaneous level of the quantity being measured. The Watt or VAR analog signals are typically fed into SCADA or telemetering equipment and are used by control centers for balancing load between control centers. Analog signals are

	typically used only for interchange metering installations. Source inputs to meter devices are Current (CT) and Voltage (VT) transformer secondary circuits. Typical input ranges for meters are 0–10 Amperes per phase and 120 VAC line-ground.
MV-90	MV-90 is a Multi-Vendor Translation system which interprets a variety of metering communication protocols used for data collection and analysis. MV-90 can poll raw impulses from recorders or meters, perform validation, editing, reporting and historical database functions. MV-90 was first introduced in 1990; hence, the *90*.
MV-90 Master Computer System (BPA)	The MV-90 Master computer system is located with BPA's central computer system. The MV-90 Master computer collects data from remote recorders on an automatic poll cycle using telephone dial out and Internet connections.
MVTs	Magnetic voltage transformers
NIST	National Institute of Standards and Technology
Parasitic Load	All electrical power required by the Large Generating Facility when the Interconnection Customer's equipment is connected to the transmission system and prepared to operate, or is in the process of start-up, or is generating. When generating, Parasitic Load includes plant auxiliary power.
RAS	Remediation action scheme
Rating Factor (RF)	The multiples of the CT rating over which the CT will retain specified accuracy and not sustain damage. There is a corresponding increase in secondary current. For example, a 1200:5 CT with an RF of 3 would be good for 3600 A primary, which would produce 15 A in the CT secondary. **Check that the maximum anticipated secondary current will not exceed the meter rating (Class).** **Note**: BPA is currently using a Class 20 meter which will accommodate an RF of 4 (20 A secondary current). Since future meters may be a different class, such as Class 10 (10 A secondary current), the present practice is to limit the use of rating factors to RF 2.
Revenue Metering	Revenue metering is metering used at points of electrical connection with BPA customers to measure demand and

energy for the purpose providing a bill to the customer. Typical installations only require kWh/kVARh interval data for each hour for billing purposes.

Revenue Metering System (RMS)

RMS is the generic term used by BPA to describe the entire revenue metering system which captures the hourly real (energy) and reactive power flow between BPA and its customers. There are two forms of RMS systems, old and new technologies. Both are accessed using MV-90.

Old Technology: The RMS system remote unit is made up of two parts: 1) the revenue meter and 2) the demand recorder. Pulses for kWh and kVARh produced by the meter are accumulated for each hour (demand interval) and are stored electronically in the demand recorder.

Current Technology: The RMS system remote unit incorporates the meter and the recorder into a single unit.

The hourly data is retrieved by the MV-90 Master computer system over a dial-up telephone or functionally equivalent system. Data is typically not needed until the end of the customer billing period but can be downloaded more often to check system operations. Revenue metering data is used primarily for customer billing but can also be used for next hour power scheduling changes, generation management, and record keeping.

RMS

Root mean square

RMS Access Agreement

An RMS access agreement is an agreement in which BPA allows the customer direct access to the Revenue Metering System (RMS), subject to certain restrictions. A BPA customer can access RMS data for their delivery points directly from the remote demand recorder. The customer must supply its own master station.

Any direct meter access requires an Access Agreement, which is coordinated through Customer Service Engineering.

Scheduled Revenue Metering

Scheduled Revenue Metering is the same as revenue metering except the meters are polled more frequently than once per day. MV-90 polls critical meters frequently for scheduling and can provide customers with the data.

Station Service Load

The electrical power required by the Interconnection Customer's Interconnection Facility substation

	equipment loads.
Supervisory Control and Data Acquisition (SCADA)	SCADA provides remote power equipment control and monitoring of power system parameters, equipment status and alarms at typically unattended substations. Controls use a “Select, Checkback, then Operate” protocol. Status and alarms are reported to the control centers. Power system parameters are developed by transducers or metering equipment in continuous form and are sampled at 2-second intervals by the SCADA terminal unit subsystem.
Telemetering	Telemetering is the transfer of data from one point to another, typically using high speed communication systems such as microwave radio or fiber. Telemetering for AGC is the transfer of continuous real time (instantaneous) kW data.
Thermal Rating Factor (TRF)	The Thermal Rating Factor is a factor by which the nominal full load current of a CT can be multiplied to determine its absolute maximum primary current without exceeding the allowable temperature rise at a defined ambient temperature.
Transient Recovery Voltage (TRV)	Transient Recovery Voltage is the voltage that appears across the contact terminals after current interruption. It is a critical parameter for fault interruption by a high-voltage circuit breaker. Its characteristics (amplitude, rate of rise) can lead either to a successful current interruption or to a failure (called re-ignition or restrike).
VT/PT	Voltage transformer/potential transformer
WECC	Western Electricity Coordinating Council

3 Background

1. This document takes precedence over any other metering application information given by BPA, either verbally or in written form.

2. This document complies with the more prescriptive requirements, rules and standards defined in the current versions of the referenced ANSI, IEEE, WECC and NERC documents. The referenced documents shall prevail should any part of this practice be found in conflict.

3. Any customer deviation from the directives in this guide must be requested in writing to BPA. All deviations must be approved by BPA in advance of installation.

4. Customers shall obtain advanced BPA approval for proposed changes from the Customer Service Engineer (or the Customer Account Executive) to customer owned metering systems or components thereof, both new and installed, including software, hardware and outdoor equipment. Changes could affect construction or energization schedules for new installations.

5. Four-wire, three element metering is accurate under all load conditions and is the BPA standard configuration. It will be used exclusively for new installations. This requires one current transformer (CT) and one voltage transformer (VT) for each phase. Refer to Section 12 for typical CT and VT connections.

6. The metering plan of service shall ensure that the instrument transformer primaries for metering and telemetering are not interrupted during possible switching configurations.

7. BPA does not allow unaccounted load in its balancing area.

8. For any customer-owned metering equipment (i.e., instrument transformers), the customer shall provide BPA with nameplate data including manufacturer's name, serial number, and type of device as well as class accuracy and pertinent input and output ratings (including impulse levels, where applicable, and necessary connection diagram and polarity designations). The customer shall also provide factory test results for each piece of equipment a minimum of 10 business days prior to energization.

9. BPA owned bidirectional revenue and interchange metering uses the BPA transmission system for power flow directional reference. For measurement purposes, *IN* is defined as energy flowing from a customer, generating station or other balancing authority area into the BPA system, and *OUT* is defined as energy flowing from the BPA transmission system to a customer, generating station, or other balancing authority area.

4 Metering Types, Ownership, and Maintenance

The division of responsibility and financial terms and conditions should be specified in an enabling agreement between BPA and the customer. Even if no money is changing hands, a letter or memorandum of understanding should be negotiated and executed to ensure both parties understand their obligations and to document the agreement.

4.1 Revenue Metering

1. Revenue Metering is the type of metering installed where the load being metered is power delivery, typically from BPA to a BPA customer, all within the BPA Balancing Area. Hourly interval data is collected by the BPA MV-90 system, using dial-up type phone communication. Data is typically retrieved daily. See Section 5 for more details.

2. BPA is responsible for the collection and accuracy of data. BPA will own the meter and associated terminal blocks and test switches in both BPA and customer owned stations to ensure better data, improved reliability, reduced cost and faster response.

3. BPA will maintain the meter and furnish copies of test data to the customer if desired. The customer will be invited to witness the testing (see Section 15, page 28).

4. BPA will require unrestricted and unescorted physical access to BPA owned meters and related equipment located in customer facilities. Details of shared locks or other requirements to obtain means of unescorted access shall be defined in an agreement.

5. BPA will provide terminal blocks for customer connections (KYZ dry contacts or instrument transformer connections).

4.2 Interchange Metering

1. Interchange Metering is the type of metering installed where BPA interconnects (interchanges) with another Balancing Area. Data requirements are continuous MW analog for input to the AGC systems of both Balancing Authorities, and hourly MWH collected at the top of each hour directly from the meter for schedule verification and as an accuracy check of the MW analog reporting system. See Section 6 for more details.

2. The meter owner must coordinate any meter changes with the other balancing authority prior to the change.

3. When the interchange meters are located in a BPA facility, BPA will own the meter at the point of interchange.

   a. Maintenance and testing will be performed by BPA and accomplished to BPA standards. The other balancing authority will be invited to witness testing and will be provided with a copy of the test results (see Section 15, page 28).

b. BPA will provide terminal blocks for external customer connections.

c. When the interchange meters are located in the facility of the other balancing authority, they shall own the meter at the point of interchange.

d. BPA will require that the meter conform to BPA's minimum specifications. Also, BPA will require that the meter be maintained and tested, at a minimum, to BPA standards. BPA will be invited to witness the testing and will be provided a copy of test data. BPA will provide its meter specifications and maintenance standards to the other balancing authority upon request.

e. The balancing authority will provide the terminal blocks for external BPA connections.

4. When interchange meters are located in a third party facility, the balancing authority for the third party customer involved will own the meter.

   a. If BPA does not own the meter, BPA will require that the meter conform to BPA's minimum specifications. Also, BPA will require that the meter be maintained and tested, at a minimum, to BPA standards.

   b. If the other balancing authority owns the meter, BPA will be invited to witness the testing and will be provided a copy of test results.

   c. If BPA owns the meter, the other balancing authority will be invited to witness testing and will be provided a copy of the test results.

   d. BPA will provide its meter specifications and maintenance standards to the other balancing authority.

   e. The owning balancing authority will provide the other balancing authority with terminal blocks for external connections.

   f. The balancing authority's meter will be the official meter of record.

4.3 Generation Integration Metering

1. Generation Integration Metering is used where a generation facility in the BPA Balancing Area connects into the BPA transmission system, either directly or through transmission facilities owned by a third party. See Section 7 for more details.

2. Generation Integration Metering can be installed at either the generation site (collector substation for wind generation) or where the transmission line from the generation site terminates at a substation.

3. Generation Integration Metering combines revenue and interchange metering types and combines data requirements from both revenue and interchange metering types.

4. BPA owns the indoor metering equipment, except when BPA's technical requirements for interconnection to the BPA grid allow the host utility to own the meter. Other aspects of maintenance and ownership depend on the situation but follow the guidelines set forth in Sections 4.1and 4.2 as appropriate regarding access, witnessing, etc.

4.4 Instrument Transformers

1. In BPA stations, BPA will own all instrument transformers.

2. In customer owned stations for revenue, interchange and generation integration metering, the customer typically owns the instrument transformers.

3. Where the customer owns the instrument transformers, BPA will require the following:

    - The customer shall purchase equipment that meets or exceeds standard specifications provided by BPA.
    - The customer shall perform a minimum of on-site acceptance testing of the instrument transformers to a standard provided by BPA, or the customer may ask that BPA perform this testing on a reimbursable basis (refer to Section 15, page 28).

4. BPA will provide the customer with standard wiring specifications and sketches to include the following:

    - Wire specifications.
    - Wire and terminal block configuration.
    - Test switches.
    - Secondary side protection.
    - Secondary side grounding.
    - Wire identification.

5. This information will be included on BPA As-Built prints.

4.5 Communication Equipment

1. For Public Switched Telephone Network (PSTN) equipment, the owner of the facility is typically responsible for making the arrangements and paying the cost for installation.

2. The owner of the facility is typically responsible for the cost and installation of ground mat potential rise (GPR) protection equipment.

3. For dedicated network solutions, such as cellular service or wireless Internet, the meter owner is the preferred owner of the communications equipment.

4. The interchange meter owner will have responsibility for any dedicated non-switched circuits (typically leased lines) or the functional equivalent.

5 Revenue Metering

1. The revenue meter shall be a solid state, bi-directional, true root mean square (RMS) measuring device that meets or exceeds ANSI C12.20 in effect at the time of design. The meter shall have the ability to record at least bidirectional kilowatt-hours (kWh) and kilovolt-ampere reactive hours (kVARh) load profile data.

2. The revenue meter must be able to provide data accumulated over a time interval. BPA's preferred interval is one (1) hour, beginning at the top of the hour. The meter shall be equipped with storage to contain all accumulated data for 40 days minimum.

3. The meter must be accessible for MV-90 data retrieval via an internal dial up modem or through an RS-232 or RS-485 port, depending on the selected communication path.

4. BPA owned revenue meters shall not internally compensate for line loss or transformer loss. Any necessary compensation is done by calculation.

5. Test blocks and switches will be located near the revenue meter. The test blocks are designed to provide a means to measure input quantities from the instrument transformers and to allow the application of test quantities (see also Section 9).

6. Revenue meters will be located inside a permanent building or inside a BPA-approved cabinet used for pole-mounted meter applications.

7. If the customer requests KYZ outputs for kWh In, kWh Out, kVARh In, and kVARh Out, dry contacts will be provided through isolating repeat relays.

8. BPA requires that the overall metering system be accurate to within ±1%.

9. Watt-hour meters should be accurate to ±0.1% at unity power factor for both full and light loads and to within ±0.3% for 0.5 power factor at full load. VAR-hour metering data should be accurate to ±0.2% at unity power factor and to within ±0.6% for 0.5 power factor. BPA will pursue correction of any suspected metering system inaccuracy of 1% or more.

10. Refer to *Technical Requirements for Interconnection to the BPA Transmission Grid* (see Appendix A).

11. BPA tariffs and individual customer contracts stipulate that metering data shall be derived from measurements obtained from instrument transformers located as near the point of delivery as practical.

12. The primary data requirements for revenue metering are kilowatt-hours (kWh) and kilovolt-ampere reactive hours (kVARh). From these quantities, the billing demand, energy, reactive consumption, and power factor are determined.

13. Revenue customers are typically billed based on three basic factors:

    - Total energy (kWh) used during the billing period. Total kWh is the summation of each hourly recorded kWh quantity during the period.
    - Reactive (kVARh). Reactive kVARh beyond an allowable dead band is billed as a penalty for poor average power factor (a function of kWh and kVARh).
    - Demand (kW). Demand is the rate of power usage. Peak demand determines required system capacity.

6 Interchange Metering

1. The interchange meters shall be solid state, bi-directional, true root mean square (RMS) measuring devices that meet or exceed ANSI C12.20 in effect at the time of design. Interchange meters also shall have the ability to record and report load profile data when used jointly as a revenue meter.

2. The interchange meter must be able to provide instantaneous analog and hourly integrated pulse data. The interchange meter must be able to scale either 0 to 1 mA or 4 to 20 mA analog outputs.

3. The meter data (kWh and kVARh) must be accessible through a port using DNP 3.0 or must be accessible by BPA via a dedicated circuit, or the customer must provide data to BPA through the Electric Industry Data Exchange (EIDE) link (control center to control center).

4. When used jointly as a revenue meter, the meter must have an RS-232 or RS-485 port or have an internal modem installed for MV-90 data retrieval by BPA.

5. Interchange meters will be located inside a permanent, climate controlled building.

6. Test blocks and switches will be located near the interchange meter. The test blocks are designed to provide a means to measure input quantities from the instrument transformers and to allow the application of test quantities.

7. BPA provides customer connections with the use of isolating equipment to electrically isolate and protect the metering data source. If the customer requests KYZ outputs for kWh In, kWh Out, kVARh In, and kVARh Out, dry contacts will be provided through isolating repeat relays. If the customer

requests analog data from BPA, either kW, kVAR or kV, it will be provided through current isolation transducers.

8. BPA requires that overall metering be accurate to within ±1%. For the meters themselves, both the BPA procurement and maintenance standards for kWh meters specify a minimum accuracy of ±0.1% at 10% and 100% full load.

9. Loads of 25 MW or less will be metered using a single combination Wh/VARh, bi-directional meter. Loads over 25 MW will be metered using two (2) Wh/VARh bi-directional meters. This is referred to as *redundant metering*.

10. A toggle switch, or selector switch, will determine which analog meter output is feeding BPA for Automatic Generation Control (AGC).

11. Interchange metering design must conform to NERC Standard BAL-005 Automatic Generation Control (AGC) and BAL-006 Inadvertent Interchange. Both continuous analog kW signals and integrated hourly kWh readings are required for interchange metering installations.

    a. The analog kW value is used by both Balancing Authority Areas (Control Areas) for AGC to maintain interconnection steady-state system frequency within defined limits by balancing real power demand and supply in real-time. Use of the kWh value is mandated as an hourly check on the accuracy and completeness of the telemetered analog value.

    b. A portion of the NERC Standard BAL-005-1 is inserted here for reference.

    > R13: Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.

    Note: ACE means Area Control Error (See Section 2, Definitions).

    c. A portion of the NERC Standard BAL-006-1 is inserted here for reference.

    > R3: Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with reading provided hourly to the control centers of Adjacent Balancing Authorities.

12. NERC Standards stipulate that metering data for both Balancing Authorities shall be derived from measurements obtained from a common metering source located at or near the point of interchange.

13. The primary data requirements for interchange metering are kilowatt-hours (kWh, the actual energy exchanged) and kilowatt demand (kW, the interchange power flow). Control Area to Control Area Net kW power flow is used to calculate the Area Control Error that drives Automatic Generation Control in real time.

14. In rare cases where it is impractical to place metering transformers and metering equipment immediately adjacent to the point where transmission ownership changes, the power system quantities measured at the nearest convenient location in the same line may be used to derive interchange quantities compensated to the actual point of interchange. There shall be no intervening transmission tap points.

15. When local supervisory control and data acquisition (SCADA) signals are not available at the metering site, the metering equipment must be monitored and alarmed in the telemetering signal. Typical alarms include, but are not limited to, the following:

    - Loss of meter potential
    - Loss of communication signals
    - Loss of metering DC supply

16. When local SCADA is available at the metering site, the three-phase loss of metering potential is monitored and alarmed directly to SCADA. For more information, refer to *Data Monitoring and Reporting Requirements for Event Recording, Annunciator, and SCADA Systems, a.k.a., Alarm Criteria* (see BPA Documents, Appendix A).

7 Generation Integration Metering

1. The integration of generation projects within the transmission system requires both bidirectional revenue metering and interchange metering. Generation plant revenue metering is further complicated by the requirement to measure relatively small amounts of energy from the transmission system to the generation plant when none of the generating units are synchronized to the grid. During these times, the local distribution utility, not BPA, is the contractual energy service provider to the generation plant customer.

2. When one or more generating units is synchronized to the transmission system, the generating plant is required to self-supply parasitic loads. Most generating units self-supply their parasitic loads when generating as a result of engineering design features that maximize generating unit reliability. Therefore, actual generating unit output is almost always the “net” of the gross unit power production minus the parasitic load.

3. BPA’s preference is for the generating plant to also self-supply non-parasitic generating plant loads, such as interconnecting substation equipment.

However, depending on physical location and engineering design, the generating plant's non-parasitic loads may be served from the local distribution utility.

4. At the customer's option, local power service provided by others may be utilized to supply electrical power required for support facilities such as administration, control room, maintenance and other buildings not incorporated within the generation facility. The distinction is defined in National Fire Protection Association (NFPA) 72, the National Electric Code. The customer is responsible for local power service and associated metering.

5. At the customer's option, an alternate power source provided by others may be utilized to maintain the generation plant when connection to the transmission system is interrupted. Separate metering is required. Arrangements for alternate power and associated metering are the customer's responsibility. However, when the plant is generating power, the parasitic load shall not be served from an alternate power source provided by others.

8 Terminal Blocks

1. Terminal blocks are required on each metering rack to provide a contact point for all external connections. Typical examples include voltage and current transformer secondary wiring and other digital and analog metering data circuits.

2. The potential and current circuits shall be wired on the terminal block in such a way that they can be readily extended to accommodate additional meters or portable instruments without taking the existing meters out of service.

3. The CT terminal block shall include provisions for shorting all terminals together where current circuits are terminated.

4. Terminal blocks shall be rated at 550 V minimum, and each shall be capable of accepting two 9 AWG copper conductors.

5. Refer to the CT and VT Connection Diagram in Section 12.

9 Test Switches

1. Each metering device shall be isolated by its own test switch.

2. Each test switch assembly shall provide three functions: meter isolation, connection points for calibration, and connection points for in-service measurement.

   a. **Voltage Elements**: Four single-pole black-handled switches shall isolate the metering device from three-phase voltage and neutral.

b. **Current Elements:** Three double-pole black-handled current switches shall first short circuit and then isolate each phase current from the metering device. Each double-pole switch shall contain an integral current test jack for measuring in-service current.

3. The typical test switch installation is shown in Figure 9-1.

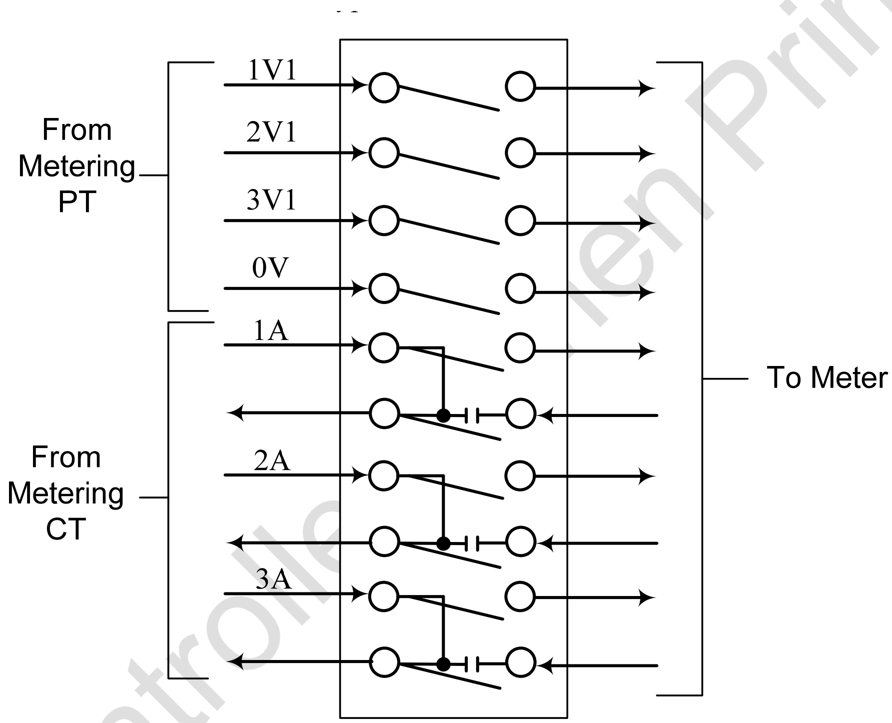

Figure 9-1.—Typical test switch

10 General Requirements for Current Transformers

1. Current transformers (CTs) shall be exclusively the metallic wound-type. Other CT types, such as optical CTs, are not presently authorized by BPA.

2. CTs should meet or exceed ANSI standard C57.13 and all applicable ANSI C12 Series standards that are in effect at the time of design. Refer to IEEE Standard C57.13.6 (2005) for high accuracy instrument transformers (see Appendix A).

3. When placing a BPA revenue meter on a customer-owned CT, the BPA meter should be first in the string of devices attached to that CT. This placement assures metering will not be inadvertently omitted from the current circuit because of testing or circuit revision.

4. Splices should be avoided in CT secondary wiring. If a splice must be made, soldered crimped splices shall be used.

5. CT secondary windings should not be connected in parallel, such as combining CTs for two lines into one metering point. Metering CTs should be located to measure line currents and should not be connected to the meter in a differential mode (where there is a difference between CTs in the substation bus located on each side of the line, as is common in a ring or breaker and a half bus configuration).

6. Three-metering-accuracy CTs, located in the line, one per phase, shall be used as the current source for interchange, generation integration and revenue metering systems. CTs shall be positioned so they measure line current for all conditions. For main-and-transfer-bus arrangements, line CTs enable proper measurement for both the normal service condition and the alternative service condition when the line breaker is bypassed. For ring-bus and for breaker-and-one-half arrangements, with breakers on each side of the line, in-line CTs avoid the problems of accuracy determination that would be encountered if a parallel connection of the breaker CT secondaries was used to get line current (differential mode).

7. Use terminal blocks with a shorting bar for all CT secondary terminations (see Section 8).

8. All CTs should conform to the ANSI standard C57.13.6 accuracy class for metering service of 0.3% or better and shall be provided with certificates of test stipulating the ratio and phase angle corrections at 10% and 100% of rating with the standard ANSI burden of B1.8 Ω (see Section 20 for CT ratio selection criteria).

9. Dual-ratio CTs can be used only if metering is connected to the full secondary ratio. The tapped down ratio does not provide rated accuracy.

10. Metering CTs at a metering point should be used exclusively for metering and AGC purposes. In cases where instrument CTs are not available, the metering CT may be used for indicating ammeters or other low-burden devices. Executed agreements must be in place before additional equipment can be added to the CT circuits.

11. The CTs shall use a shielded design in order to prevent unintentional energization of the transformer secondary during an insulation failure.

12. Section 20 discusses the process of selecting CT ratios for both BPA and BPA customers providing CTs for BPA metering points.

11 General Requirements for Voltage Transformers

1. The terms Voltage Transformer (VT) and Potential Transformer (PT) are used interchangeably.

2. All VTs shall conform to the ANSI standard C57.13.6 accuracy class for metering service of 0.3% or better and shall be provided with certificates of test stipulating the ratio and phase angle corrections at 100% rating with zero burden and with the rated maximum standard burden. VTs purchased for revenue metering with 350 kV basic impulse level (BIL) and below shall have a 0.3% accuracy class at burdens W through Z, inclusive; VTs purchased for revenue metering with 550 kV BIL and above shall have 0.3% accuracy class at burdens W through ZZ, inclusive (see Table 11-1).

Table 11-1.—Standard Burdens for VTs (or PTs)

Burden	Volt-Amperes at 120 V	Burden Power Factor
W	12.5	0.7
X	25.0	0.7
Y	75.0	0.85
Z	200.0	0.85
ZZ	400.0	0.85

3. Select VT ratios shall be consistent with the phase-to-ground voltage to be monitored. VT primaries are connected phase-to-ground. Transformer secondary voltage (meter potential) is nominally rated 120 volts phase-to-ground (1V1, 2V1, 3V1 and 0V).

4. VTs may be used as follows:

   - Above 230 kV: Capacitor voltage transformers (CVTs) shall be used.
   - 230 kV and below, main and transfer bus layouts: Magnetic voltage transformers (MVTs) shall be used for bus potential.
   - 230 kV and below, ring bus and breaker and a half: MVTs shall be used except where MVTs are susceptible to ferroresonance when applied to circuit breakers that contain grading capacitors or transient recovery voltage (TRV) capacitors. In this case, CVTs will be used.

5. Capacitor voltage transformer (CVT) outputs should be measured for drift periodically (typically every 6 months) for safety reasons. Secondary voltage drift is an indication of possible failure of the CVT. MVTs maintain accuracy over time and are therefore preferred unless safety issues prohibit their use.

6. The VT secondary circuit shall be protected by air circuit breakers (ACBs) (or cartridge fuses with plastic shells) installed at the VT pedestal junction box in the yard. The device shall also provide an isolating point for the purpose of lockout/tagout. The ACB trip rating or fuse element rating shall be 10 A.

7. A properly protected separate circuit shall be provided from the voltage transformer secondary for all other uses such as voltage and frequency transducers, panel mounted and recording voltmeters, synchronizing, etc. The circuits for metering and other equipment must be separately protected in the control building (see Figure 11-1).

8. The PTs shall use a shielded design in order to prevent unintentional energization of the transformer secondary during an insulation failure (see Table 11-1).

9. Splices should be avoided in PT secondary wiring. If a splice must be made, soldered crimped splices will be used.

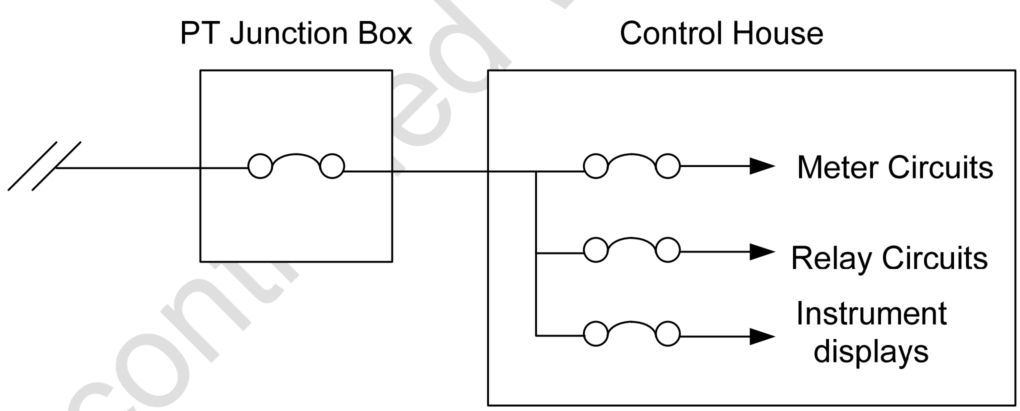

Figure 11-1.—Typical secondary PT protection

12 Instrument Transformer Connections

1. Typical CT and VT connections are shown in the following figure:

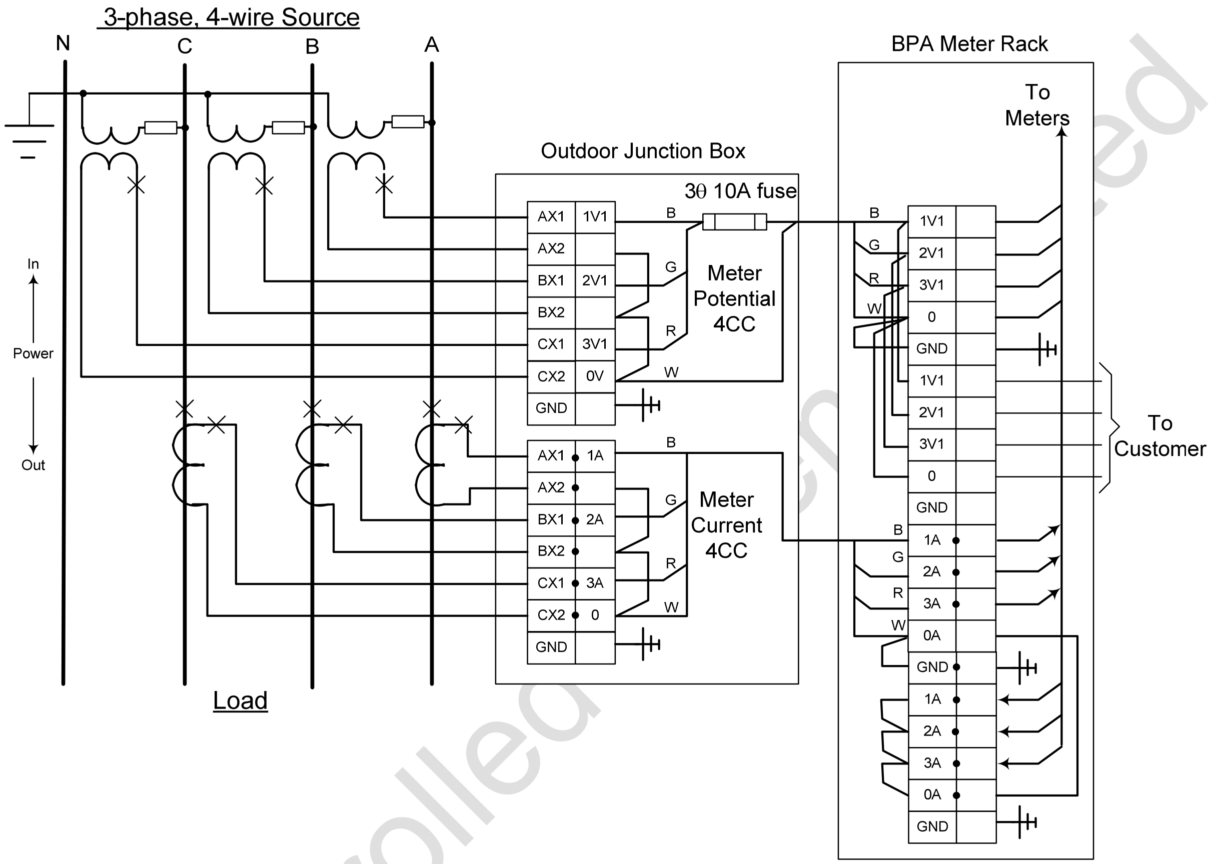

Figure 12-1.—An elementary wiring diagram utilizing four conductor cables

a. The neutrals in the CT and PT cables are grounded at only one point. BPA grounds this lead at the first entrance point in the control house.

   (1) Shielded cable is grounded at the junction box and at the entrance of the control house.

   (2) As shown, 1V1, 2V1, 3V1, 0V are nominal 120 VAC phase to ground.

   (3) Refer to EPADS reference drawing 274159, sheet 1, titled "230/115/69/34.5/14.4kV – 120V Revenue Metering Junction Box Wiring." Also refer to EPADS reference drawings 271019, sheet 1, titled "115/230kV Junction Box L/O for Synch. Pot. Ckt."

   (4) Fuses should be applied to the primary side of PTs for distribution voltages. Expulsion links should be used for transmission voltages.

13 Outdoor Cables and Wiring

13.1 Outdoor Secondary Cables

1. All outdoor PT and CT secondary cables between the junction box and the meter house shall be configured as follows:

   - Individual conductors shall be easily identifiable by color code or equivalent.
   - Copper shielded cable shall be rated at 600 volts or higher
   - For all single spans, all cables shall be 9 AWG or equivalent (0.8 Ω per 1000 feet). Non-BPA sites may use 8 AWG cable (0.62 Ω per 1000 feet) or 10 AWG cable (0.99 Ω per 100 feet).

13.2 CT Secondary Cables

1. The required number of conductors for CT secondary cables is listed in Table 13-1.

Table 13-1.—Required number of conductors per phase for CT secondary cables

Distance Between Junction Box and Meter House	Required No. of Conductors per Phase
0–600 ft	1
600–800 ft	2, in parallel *or* Equivalent larger conductor***** (6 AWG, 0.4 Ω per 1000 ft)
800 or more ft	3, in parallel *or* Equivalent larger conductor***** (4 AWG, 0.27 Ω per 1000 ft)

* The equivalent larger conductor must meet BPA burden ratings

13.3 Routing

1. Cable should be routed according to BPA's *Electromagnetic Interference (EMI) Policy* (see Appendix A).

2. Cable should be limited to the minimum length necessary to complete the circuit to the metering device.

13.4 Grounding

1. Cables between the instrument transformer and the junction box shall be run in a grounded metal conduit.

2. Shielded cable shall be used between the junction box and meter house.

3. Cable shields shall be grounded.

4. The meter rack/box/cabinet and junction box shall all be grounded.

5. Instrument transformer neutrals shall be grounded in only one location and as per the owning utility's practices.

13.5 Conduit

1. **Below Ground**: All conduit installed below ground must be plastic, typically polyvinyl chloride (PVC). Conduit shall have a minimum 2 inch diameter and shall contain a maximum of two (2) four-conductor cables. For installations that require a seven conductor cable for a CT circuit, the conduit diameter size should be a minimum of 2½ inches.

2. **Above Ground**: Use metal conduits, rated for electrical use, for all above ground installations. Conduit should be sized between ¾ inch and 1½ inch diameter.

13.6 Meter Cabinets

When air circuit breakers (ACBs) are placed in outdoor meter cabinets, the cabinet should be a NEMA 3R enclosure, with screened vents in two locations. In the majority of locations, the meter itself provides enough heat to prevent corrosion on the ACBs. When placing the meter cabinet in an exceptionally damp location, 10-W thermostatically controlled heaters should be installed in the cabinet.

13.7 Junction Boxes

1. Noncorrosive fuses shall be used inside PT (or VT) junction boxes.

2. The following figure shows a sample 10-A fuse approved for use in PT and VT junction boxes. The fuse reads 0.3 Ω when installed.

(a) (b) (c)

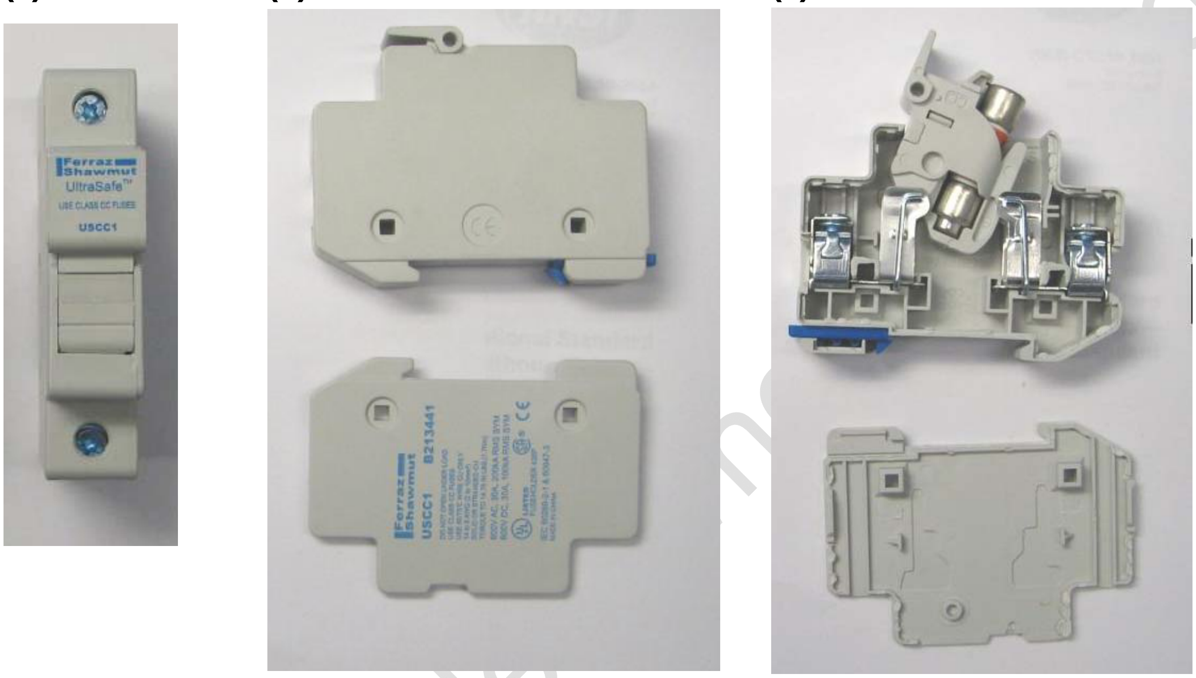

Figure 13-1.—A sample 10-A fuse: (a) front view, (b) exterior view of disassembled fuse, and (c) interior view of disassembled fuse

14 Validation of Data

14.1 Revenue Metering Data

1. BPA's meter will be the source of certifiable final data in installations where customers install their own measurement devices.

2. Where applicable, revenue data may be checked against SCADA data for validating reasons.

14.2 Interchange Data

1. BPA and the interconnecting Balancing Authority will comply with NERC Standard BAL-005 Automatic Generation Control and Standard BAL-006 Inadvertent Interchange.

2. A portion of the NERC Standard BAL-005-1 is inserted here for reference:

> R12.1 Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

3. A portion of the NERC Standard BAL-006-1 is inserted here for reference:

> R3 Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of adjacent Balancing Authorities.

15 Testing and Calibration

1. BPA will perform, or require the customer to perform, tests at least every two years on all revenue, generation integration and interchange meters, unless requested more frequently by the customer or required contractually. The testing party will contact the other party a minimum of 2 weeks in advance of the test date, when testing needs to be witnessed.

2. Customers will provide BPA with copies of test data. BPA will provide test data upon request.

3. For interchange meters, verification of the AGC signal emanating from a common, agreed upon source to both Balancing Authorities will be performed every two years during the meter test.

4. Standards used for meter calibration shall be calibrated yearly and traceable to the National Institute for Science and Technology (NIST) Standards.

5. BPA may install test equipment in parallel with customer test equipment or may compare standard tests.

6. BPA, in cooperation with the customer, shall make any necessary internal software scaling factor changes or channel changes.

7. In-service PT and CT checks will be performed at the time of initial meter energization and at the completion of meter calibration. In-service checks are measurements of amplitude and phase angle of actual load. CT in-service checks will be done with and without test burden.

8. During in-service tests, live quantities are being transmitted to kWh Master, AGC, etc. These tests require sufficient load be available to perform valid measurements.

9. All implemented meter outputs should be tested for accuracy and performance.

10. If the meter has internal compensation, the compensation settings data will be documented. Additionally, the compensated meter will be tested in both uncompensated and compensated configurations.

11. During initial installations, when the customer is responsible for testing instrument transformers, the standard baseline tests shall include the following:

    - Insulation resistance test
    - Nominal ratio check
    - Polarity test

12. The customer shall notify BPA a minimum of 2 weeks in advance of the test date. The customer shall provide BPA with all acceptance test records to verify the transformers meet required specifications.

13. During initial energization of interchange and integration meters, all digital and analog quantities are simulated to ensure the Balancing Authority(s) receives the correct indication(s).

14. For new installations, communication circuits will be verified for proper operation during a required 30-day burn in period.

15. Release to operations means that all work is complete and has been verified and that in-service tests are complete and the facility is available for dispatch.

16 Exchange of Information

16.1 Prior to Meter Installation

The customer shall provide all associated connection diagrams, nameplate ratings, secondary burdens, and test certificates for current and potential transformers used for revenue metering.

16.2 Revenue Billing

16.2.1 kWh and kVARh Data

(1) The kWh and kVARh data is gathered at least every 24 hours from revenue meters by BPA's MV-90 system. Revenue billing data is stored in BPA's MDM (Meter Data Management) system and is available to customers over the Internet.

(2) Any direct meter access requires an Access Agreement, which is coordinated through Customer Service Engineering.

16.3 Interchange Accounting

16.3.1 kWh Data

(1) At interchanges, the owner of the meter should collect the kWh data and send it to the other control area within five (5) minutes after the top of the hour.

(2) The kWh data from interchange meters is gathered by BPA's kWh Master via dedicated communication circuits.

(3) BPA will use EIDE protocol to exchange kWh data. EIDE protocol has been developed by the Western Electricity Coordinating Council (WECC), Western Interconnection Tool working group. EIDE is an XML based communication protocol. Utilities can use the EIDE system to exchange the hourly data.

16.3.2 *kW and kVAR Data*

(1) BPA exchanges with other utilities real time data (megawatts) that has been directly telemetered to both BPA control centers.

(2) Each control area interconnection (i.e., interchange) shall be equipped with a common kW meter, with readings provided to a control center for exchange between utility control centers.

(3) For generation integration metering, kW and kVAR data is made available for the generation owner via isolating transducers.

16.4 Meter Test Data

Refer to Section 15, Testing and Calibration.

16.5 Sign Conventions

16.5.1 *IN and OUT Definitions*

(1) *IN* and *OUT* and their equivalent terms (see below) refer to electrical power flowing towards or away from a reference. Typically, that reference is the serving utility (BPA in this case), so power flow to BPA from a source is IN and from BPA to a load or customer is OUT.

(2) Also typically, the substation bus represents BPA so power flowing into the substation is IN and away from the substation to a customer is OUT. Since the bus is the usual reference, metering CTs for the attached transmission lines are connected with their polarity such that power flowing out of the bus (out of BPA) to the line will cause the meter to read in the OUT direction and store data in the meter's OUT data registers.

16.5.2 *Equivalent Terms*

(1) Common usage and meter manufacturers' terminologies for power flow directions have resulted in multiple terms meaning the same thing as shown below:

- IN: *Minus* (-), *Received*, and *Reverse* all mean the same—flow into the reference.
- OUT: *Plus* (+), *Delivered*, and *Forward* all mean the same—flow out of the reference.

16.5.3 *Revenue and Interchange Metering INs and OUTs*

(1) Both revenue metering (MV-90 dial-up data access) and interchange metering/telemetering use the "BPA is the center of the world" view for metering data direction as described in definitions above.

(2) Power flow away from BPA, either to a customer load or to another Balancing Authority, is OUT or plus (+). Power flow into BPA from either a customer or another Balancing Authority is IN or minus (-).

(3) If the interchange metering is provided by the other balancing authority, usually because the interchange point is in their facilities, kW and kWh data must be furnished to BPA in a suitable manner. The IN and OUT polarity of the data must be checked at Dittmer because it may be furnished to BPA with the same polarity that is used by the other party, which is the reverse of what BPA needs. What is OUT to the other balancing authority is IN to BPA.

16.5.4 Generation Integration INs and OUTs

(1) Integrating a generation source into the BPA system requires both revenue and interchange type metering and data. For revenue metering the normal laws apply, and generation is seen as coming into the BPA system and so has an IN or minus (-) designation.

(2) For reasons somewhat lost in history, generation MW and kWh, even though they come into the BPA system, must be treated at the BPA Dittmer Control Center for control purposes as being a plus (+) or OUT quantity.

(3) This raises obvious data difficulties since the data direction requirements for revenue and for Dittmer interchange-type data are opposite but come from the same meter. The meter, depending on CT polarity connections, will see generation as being either IN or OUT but not both. The solution is in how the data is processed after the meter records it.

- For revenue metering, the BPA Meter Data Management (MDM) system assigns a direction to the data after it is retrieved from the meter by MV-90. Thus, if generation data is recorded on a meter register called “delivered” (OUT) because of CT polarity, the data sign could be reversed by assigning a “received” (IN) label in MDM.
- For Dittmer MW and kWh data:
  - MW direction (polarity) can be reversed at the site if necessary by rolling the inputs to the SCADA (reversing plus [+] and minus [-]) or at the Dittmer SCADA Master in the data base.
  - For kWh to the Dittmer kWh Master, there is a data option in the KWh Master that automatically reverses plus (+) and minus (-) as received from the meter when needed.

(4) The most common, and the preferred, CT polarity connection will see the generation as being an input to the local station bus and will register generation as being IN. This means the data reversal is most commonly applied to interchange data, not revenue/MV-90 data.

(5) All these things must be carefully explained in the BPA Metering and Telemetering Requirement Memo, issued by Design for each metering project.

17 Communication Circuits/Paths

17.1 Communication Path Options

17.1.1 Revenue Metering Requirements

(1) The Revenue Metering System (RMS) requires one of four (4) communication paths in order to be accessed by MV-90:

- DATS (Dial Automatic Telephone Switching) – BPA's private telephone system
- Voice grade commercial telephone line (PSTN - Public Switched Telephone Network) or its functional equivalent
- Cellular service
- Internet Protocol access

17.1.2 Installation

(1) A PSTN telephone line, with proper ground mat rise protection, will normally be installed unless the cost is prohibitively expensive.

(2) Digital cellular, because of ease of installation, is becoming more common and is a suitable alternative to a land-line PSTN.

17.1.3 Interchange and Generation Integration Metering Requirements

(1) Generation Integration and select Interchange metering require support for MV-90 (see 17.1.1).

(2) Both Generation Integration and Interchange metering require continuous communication paths required for real time data (kW and kWh, occasionally kVAR, kV and Loss of Meter Potential). The following paths qualify:

- Utility-owned fiber
- Utility-owned radio
- Leased line (dedicated circuit)

17.2 DATS

RMS may use existing DATS phone lines (part of BPA's telecommunications system) if available at the metering site. New communications channels will not be provided to add DATS solely in support of RMS. Since it uses radio or fiber circuits, DATS is unaffected by ground mat potential rise (GPR). Use of DATS does not permit direct customer access to metering data from the meter.

17.3 Leased Lines

1. For metering purposes, the typical leased line is an analog voice-grade circuit (see Appendix A for the Leased Line Technical Specification, BPA, *Requirements for Multi-tone Circuit – Voice Grade*).

2. Leased lines will require the same GPR protection as a PSTN (see Section 17.4).

17.4 PSTN (Commercial Telephone)

17.4.1 Protection

(1) PSTN metallic circuits must have proper protection from GPR based on the expected maximum GPR (GPR Peak V) or GPR with DC offset at each site (refer to BPA, *Grounding Data List* in Appendix A). A ground mat rise study will be needed to determine the level of protection. Protection responsibility will be defined in the agreement between BPA and the customer. Protection may be provided by either the commercial telephone company or by BPA. All metallic lines entering the station must be protected to the same voltage level. Protection presently provided by BPA is a Telephone Isolation Device/Shelf (typically, Positron isolation equipment and cabling). PSTN cable sheath shall be grounded only at the central office cable interface. The cable sheath shall not be grounded to the substation ground mat (see also IEEE Standard 487-2000 in Appendix A).

(2) PSTN protection is not necessary when the PSTN line enters a pole mounted meter cabinet.

17.4.2 Installation

The design for new substations will include a dedicated, buried, schedule 80, 4-inch diameter PVC conduit with long radius bends from the control house/meter house/ meter cabinet to a location at the 300-V point outside the substation fence for telephone line entry. The telephone cable shall not be direct buried. Metallic conduit shall not be used anywhere in the conduit run, to avoid bridging between the ground mat and offsite locations. The large diameter conduit is necessary to allow long uninterrupted telephone cable installations with multiple bends. Further, the cable typically has a high-voltage insulated jacket and is quite stiff. Separate isolation device cards (typically, Positron) will be used for each PSTN line and dedicated circuit entering the substation.

17.5 Cellular

1. The coverage area of cellular service is constantly expanding and now reaches many remote substation sites. There are several advantages to choosing cellular data service over telephone. The main advantage of cellular is the isolation from the effects of GPR. The cost of installation and monthly usage is also often less than a PSTN line with the required protection (see above) and rate structure. A second advantage to cellular data is fast connection time such as 5 seconds versus 45 seconds per meter poll. Connections using serial over IP eliminate the analog conversion stages at

central master stations and meter sites. New meters with IP connections will not impact the central master station's modem-telephone line capacity.

2. Cellular hardware at the site must support a serial connection to the RMS and must convert data to serial over IP across the public Internet. The cellular option should be evaluated at each new RMS site, even in urban areas where standard PSTN phone service is available.

3. Cellular hardware that provides analog telephone signals to the RMS modems and uses circuit switched data should not be proposed for new projects.

17.6 Internet Protocol (IP)

1. In order to plan for the adoption of Internet Protocol (IP) access of revenue meters, all new revenue meters will be required to have a serial port or Ethernet port option as an alternative to the telephone modem.

2. For interchange metering, BPA requires DNP3 access using the primary serial port. A second serial port or telephone modem can support customer access to read the meter profile from public Internet or dial out modems.

17.7 Utility-Owned Fiber

For metering purposes, Communications Planning determines the use of utility-owned fiber.

17.8 Utility-Owned Radio

For metering purposes, Communications Planning determines the use of utility-owned radio.

18 Typical Applications

18.1 Typical Revenue Metering Application

1. In a typical revenue metering application (see Figure 18-1), BPA's MV-90 Master reads internal meter pulse registers to obtain hourly demand information.

2. Upon customer request, BPA will install isolating repeat relays to provide hourly kWh and kVARh pulses, both IN and OUT quantities. These pulse outputs are in the form of dry contacts.

3. Any request to access revenue meters directly shall be made to BPA's Customer Service Engineer.

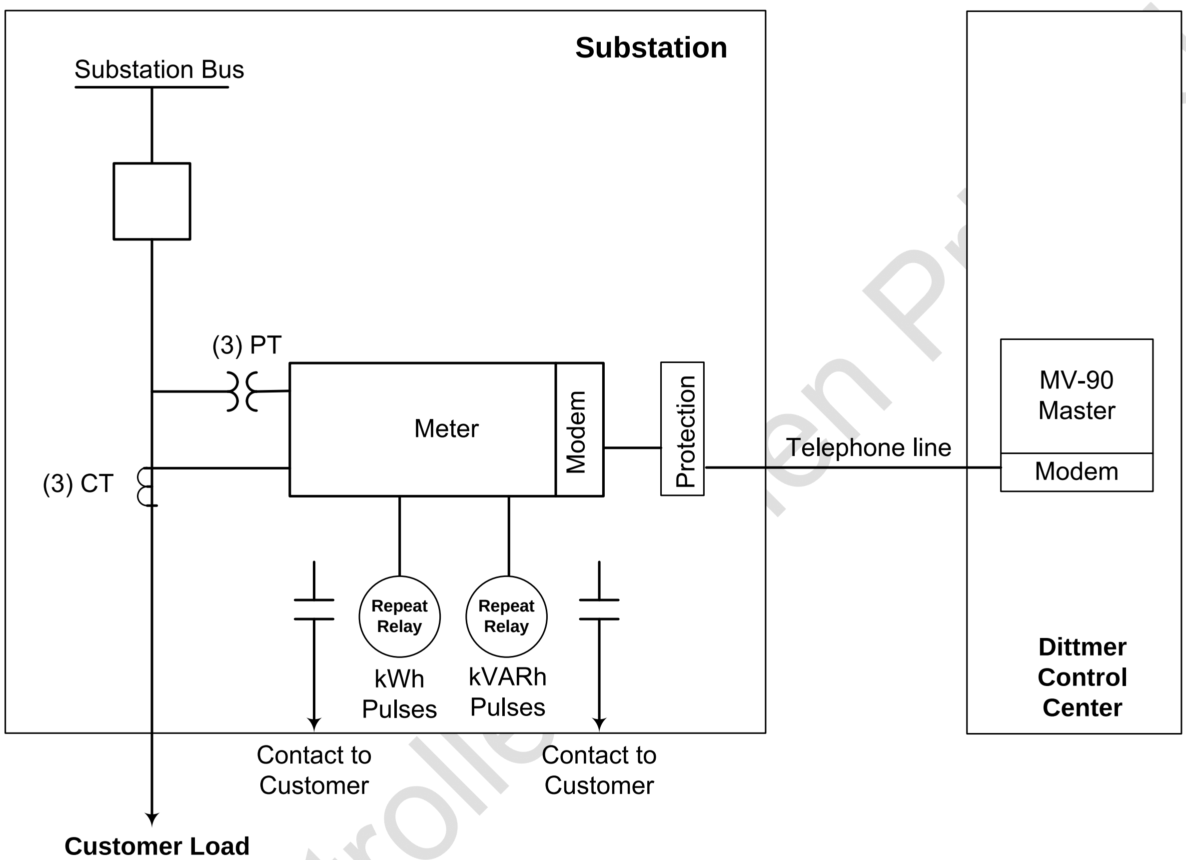

Figure 18-1.—The typical revenue metering application

18.2 Typical Interchange Metering Application

1. Typical interchange metering installations (see Figure 18-2) utilize Watt and VAR analog outputs from the meter, which are used as BPA's AGC source via BPA's SCADA system. If BPA does not have a SCADA system at the metering location, then these instantaneous quantities are telemetered to BPA's nearest SCADA-monitored facility. Conforming to NERC regulations, the telemetered kW quantity is also made available to the adjoining Balancing Authority.

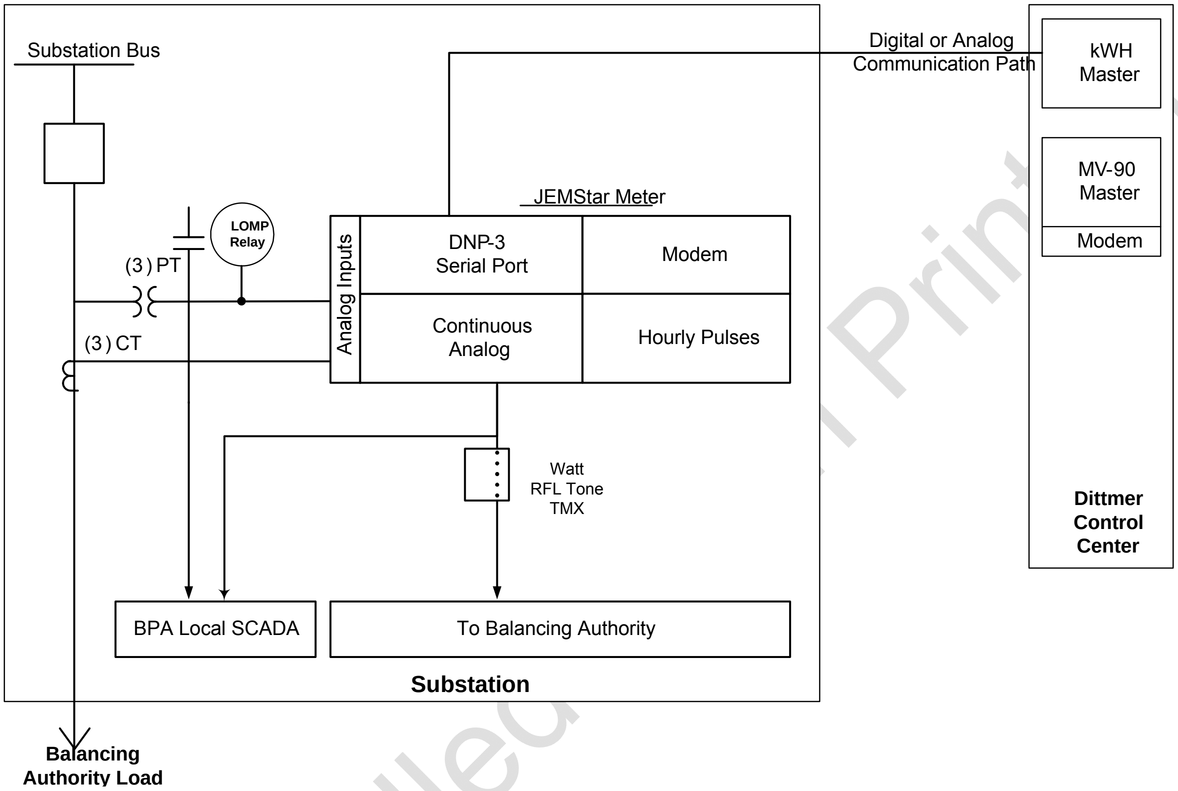

Figure 18-2.—The typical interchange metering application

2. The hourly kWh demand information is collected directly from the meter's internal registers by BPA's kWh Master. This operation occurs shortly after the end of the demand interval. A dedicated communication circuit is assigned for this function.

3. If the meter point serves both as an interchange and revenue point, then BPA's meter can be equipped to provide data for both functions. The MV-90 Master will then poll the meter for hourly data.

4. Upon request, BPA will provide analog signals through an analog isolating transducer(s). Similarly, the meter pulse outputs can be provided through isolating relays. Alternative transducers can provide data access methods not provided by BPA's standard installation; however, data so obtained can be used for indication only.

18.3 Typical Generation Interchange Metering Application

1. Figure 18-3 shows the typical large generation integration metering application.

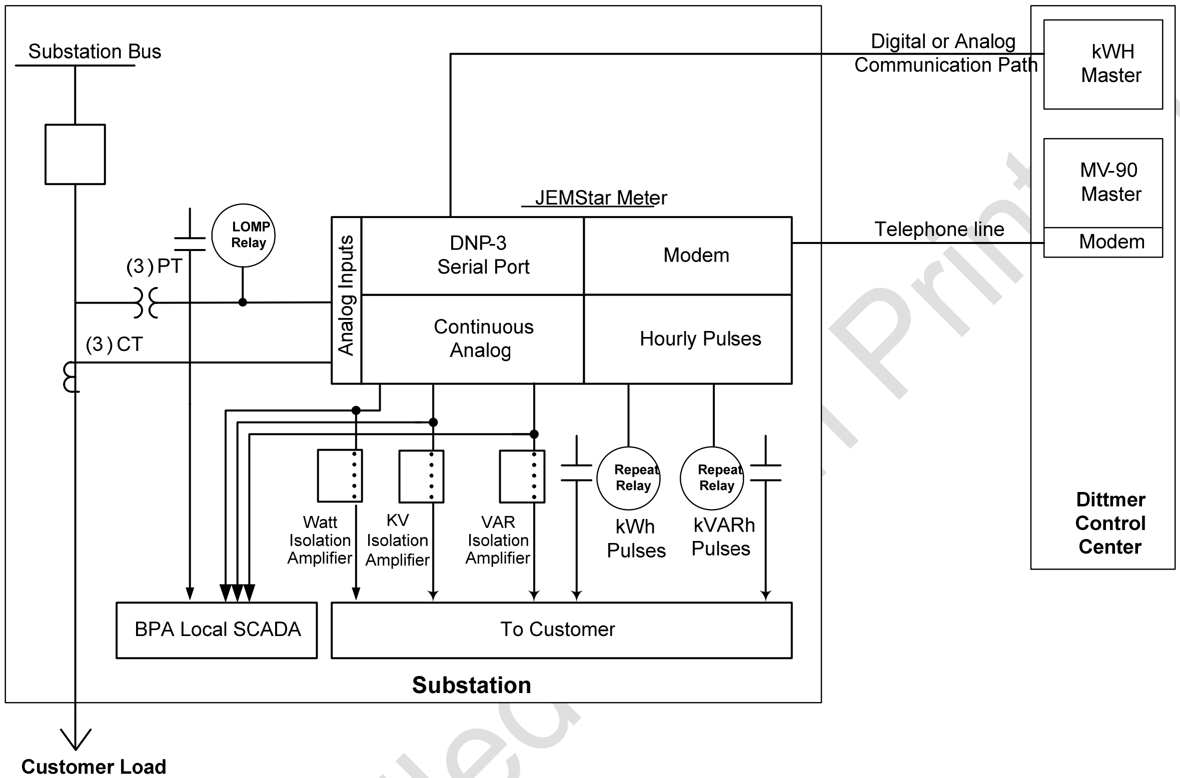

Figure 18-3.—The typical large generation Integration metering application

19 Special Considerations

19.1 Replacement Metering

Replacement metering may match the existing configuration, although upgrading from two-element to three-element metering is highly desirable to yield greater accuracy.

19.2 Loss Compensation

BPA meters are not adjusted for loss compensation. Necessary loss compensation is factored into the specific billing calculation for the point of delivery. Loss factors are calculated using the physical characteristics of any transmission lines, power transformers and voltage regulators located between the contracted Point of Delivery and the actual meter location. Customer cooperation is required to obtain transmission line characteristics and manufacturer's factory test reports of power transformers and voltage regulators. BPA Customer Service Engineering performs loss factor calculations and provides them to the customer for review.

19.3 Customer Metering and Indoor Equipment

1. Upon request to BPA Customer Service Engineering, BPA will consider allowing customer metering equipment in addition to the BPA meters on BPA-metered points. The following conditions apply to such considerations:

    a. The official meter of record is the BPA meter(s).

b. The BPA meter(s) is (are) the “first in line” for CT and PT secondary wiring.

c. The Customer meter will not be located on the BPA metering rack. An exception may be granted if it is physically impossible (not just inconvenient) to locate the Customer metering equipment anywhere else and if BPA has no known future plans for the rack space.

d. Should BPA have need in the future for rack space granted under the above condition for Customer metering equipment, the Customer metering equipment must be relocated at the Customer’s expense.

e. The Customer is responsible for installation and maintenance of its metering equipment. Customer metering equipment shall be installed such that activity upon stated equipment shall not affect the operation of the BPA meter and vice-versa.

f. A written agreement shall be executed between BPA and the Customer prior to extending metering circuits from the BPA meter(s) to the Customer metering equipment. This agreement has the general purpose of ensuring that metering circuit extensions are done in agreement with BPA practices and do not jeopardize the BPA meter(s) in any way. This agreement will address all the issues stated above.

g. The Customer is responsible for any communication systems needed by its metering equipment.

19.3.1 Extending BPA Metering Circuits to Customer Metering Equipment

(1) Figure 19-1 illustrates the methods and requirements to extend BPA metering circuits to Customer owned metering equipment.

- Currents shall be run in series from rack to rack.
- Metering potentials shall be paralleled from rack to rack with ACB or fuse protection.
- Customer metering equipment shall be isolated with test switches (refer to Section 9 on Test Switches).
- Multiconductor cable shall be used for inter-rack wiring.
- Terminal blocks on BPA’s meter rack shall be the official demarcation point.
- Terminal blocks shall be wired in accordance with the Section 8 (Terminal Blocks).

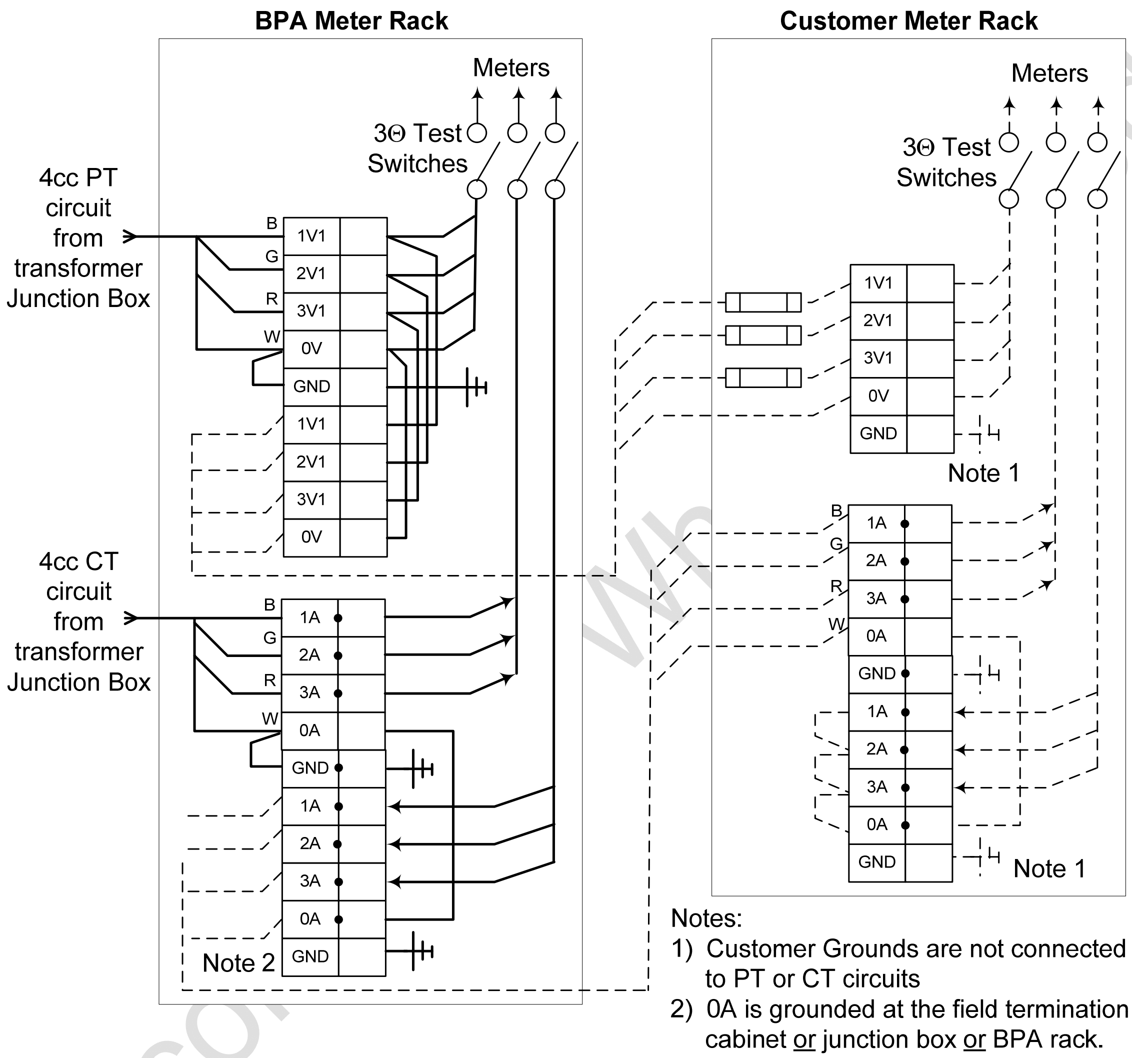

Figure 19-1.—Extending BPA metering circuits to customer metering equipment

20 Technical Application of Current Transformers

Note: BPA has revised CT purchasing specifications for 69 kV through 230 kV CTs (the voltages at which BPA most commonly supplies CTs) so that by using commercially available combinations of extended range and accuracy, one CT ratio at each voltage level will meet seismic requirements while providing 0.3% or better accuracy at Burden B1.8 over the entire normally expected load range at these voltage levels. This same philosophy will apply should BPA purchase CTs at other voltage levels. Refer to Table 21-1.

Customers supplying CTs for BPA metering in Customer owned facilities must use this same selection philosophy. They may select the same CT ratio and combination of extended range and accuracy as used by BPA or demonstrate that the CT selection that is made will meet the 0.3% at burden B1.8 criteria over the expected load range of the Customer facility being metered. This requirement applies to all voltage classes, not just the ones at which BPA has standardized CT purchases.

20.1 CT Applications for Metering

20.1.1 Definitions for This Section

The following definitions are used in the CT ratio selection and calculations and bear repeating here.

CT Rating	The primary current at which the CT produces 5 A in the secondary circuit to the meters. For example, a CT with a rating of 1200 A would be expressed as 1200:5 ratio and would produce 5 A secondary current at a 1200 A primary current.
CT Burden Rating	The maximum secondary current circuit resistance, in Ohms, including wire leads and all connected equipment, at which the CT will maintain rated accuracy. The maximum standard burden rating normally available is B1.8, which is what BPA requires in BPA and in customer supplied CTs. Higher burden ratings will result in more "robust" CTs, better able to retain accuracy during challenging and varied conditions. This is why BPA specifies B1.8 The general design criterion for CTs is minimum burden, which increases accuracy. This may mean doubling up on conductors for long runs from the CT to the meter, or increasing conductor size, to minimize lead resistance.
Rating Factor (RF)	The multiples of the CT rating over which the CT will retain specified accuracy and not sustain damage. There is a corresponding increase in secondary current. For example, a 1200:5 CT with an RF of 3 would be good for 3600 A primary, which would produce 15 A in the CT secondary. **Check that the maximum anticipated secondary current will not exceed the meter rating (Class).** **Note**: BPA is currently using a Class 20 meter which will accommodate a RF of 4 (20 A secondary current). Since future meters may be a different class, such as Class 10 (10 A secondary current), the present practice is to limit the use of rating factors to RF 2.

Extended Range	Extended Range is operating beyond the normal ANSI CT range of 10–100% of CT Rating. This increases the high and low range over which accuracy is maintained. Standard accuracy is extended to both the high end of CT rating (see Rating Factor) and to the very low end of the load range, often to 0.5% of CT rating. For a 1200:5 CT, low end would be extended to 6 A primary current (1200 A $\times$ 0.005 = 6 A).
Extended Accuracy	Increased accuracy—usually 0.15% rather then the normal 0.3%—extends over most of or all of the range of the CT. Accuracy does not decrease as loads get smaller as allowed by ANSI specification C57.13. When extended accuracy is combined with extended range, CTs are available in some voltage classes that are 0.15% from 0.5% to 400% of CT Rating.
ANSI Standard Accuracy (C57.13)	ANSI specifications call for 0.3% accuracy at 100% of load rating and 0.6% accuracy at 10% of rating. Operating below 10% of the CT Rating accuracy is undefined. Fortunately, most CTs perform much better than this, with 0.3% accuracy often extending down to 5% of CT Rating. But the ANSI standard by itself does not provide the 0.3% accuracy over the entire load range that BPA requires.

20.1.2 The following are to be specified when purchasing CTs:

- Accuracy Class (such as 0.3%, which is what BPA requires)
- Burden (BPA requires B1.8)
- Nominal System Voltage Rating (such as 115 kV)
- Basic Impulse Level (BIL) (such as 550 kV)
- Physical Feature (such as oil filled)
- Thermal Rating Factor (such as 2.0)
- Transformation Ratio (such as 1200:5)

20.2 CT Ratio (CTR) Selection Criteria

1. The overall intent of CT ratio (CTR) selection for both BPA and for customers providing CTs is to maintain 0.3% metering accuracy at burden B1.8 over the entire expected load range being metered. Tools to accomplish this include judicial CT ratio selection, the use of CTs with expanded low current and high accuracy capability and using CT rating factors as needed.

2. The following items should be considered when selecting a CT ratio for a typical metering application (Also see Section 10 for more general CT requirements).

3. Minimum Load

   a. For standard CTs, minimum load should not be less than 10% of CTR due to loss of CT accuracy. For loads that routinely will be less than 10% of CTR, use of CTs with extended low current capability is required.

   b. For planning purposes, unless other data is available, the average load for a new, general purpose (not commercial/industrial) metering point is assumed to be 60% of peak demand, and minimum load is assumed to be 30% of peak demand. A temporary minimum load of less than 10% may be tolerated if projected load growth shows that a rapid load increase is expected.

4. Peak Loads

   a. Peak loads should not exceed 100% of CTR multiplied by the CT rating factor because of CT thermal limitations. When using Class 20 meters, CTs with rating factors up to 4 can be used for loads that have a very wide light load to heavy load spread, or for loads that have a large contingency load compared to normal loads.

   b. Note that the use of CTs with expanded low current and high accuracy capability may allow use of higher CT ratios and lesser rating factors because of improved low end CT performance.

5. Transmission Line Loading Factor: On transmission line applications, CTs should be selected to operate continuously at the long-term emergency thermal rating of that transmission line without exceeding the thermal capacity of the CT and while maintaining 0.3% or better accuracy unless other information, such as the maximum output of a connected generator or transformer, would indicate otherwise.

6. Asymmetric Flow: For applications such as metering generation which have both the generation output and very small quantities of station service reverse flow during non-generation periods, CTs should be of extended range, extended accuracy type to maintain 0.3% or better accurately for meter loads at the station service levels.

20.3 CT Tables and Design Considerations

20.3.1 BPA Purchasing Standards

The following table shows the 69 kV through 230 kV meter purchasing specifications that BPA is using for all CTs in those voltage ranges. These CTs are all 0.15% B1.8, have extended accuracy, extended range (RF2), and are all seismically qualified per IEEE 693-2005, high level. Note that there are no 500 kV CTs listed, as seismic qualification has been a problem. Should there be a future need for 500 kV metering CTs, the engineering issues will be addressed at that time.

Table 20-1.—Standard BPA CT Ratios for 69 kV, 115 kV, and 230 kV

Voltage and Type	Ratio	Span of 0.3% or Better Measurement Accuracy	BPA Catalog No.
69 kV; Oil Type	1000:5	0.8 A to 2000 A primary current 0.096 MW to 239 MW	1010857
69kV; Dry Type	1000:5	0.8 A to 2000 A primary current 0.096 MW to 239 MW	1011048
115 kV; Oil Type	1000:5	0.8 A to 2000 A primary current 0.16 MW to 398 MW	1010940
230 kV; Oil Type	2000:5	1.6 A to 4000 A primary current 0.637 MW to 1593 MW	101076

20.3.2 CT Selection Design Process Considerations

(1) Once a metering point's maximum and minimum load points are determined, the next step is to select a CT that will provide metering accuracy (0.3% or better) over that load range. BPA will use CTs per the new Purchasing Standard set forth in 20.3.1 in all cases where it applies. Otherwise, a selection process must be undertaken as described in the following.

(2) Standard CTs may be adequate in many situations, but manufacturer's test data will probably be needed to confirm 0.3% accuracy, particularly at the lower end of the rating. Or, it may be necessary to balance different combinations of ratios, extended ranges and extended accuracies to obtain the best result. This is all part of the design process.

(3) Table 20-2 shows the effects on a typical 1000:5 CT that can be obtained by applying various combinations of extended range and extended accuracy to a standard CT. The same procedures applied to different CT ratios will yield different primary amps.

Table 20-2.—Typical Metering CT, 1000:5 A
(what may be considered when selecting a CT for a specific application)

Percent of Rating	Primary Amps	Comments
0.5%	5 A	Requires extended range (this is less than normal10% of rating) and extended accuracy.
5%	50 A	Standard CT MIGHT provide 0.3% accuracy at 5% of rating. Check manufacturer's test data to verify. Otherwise extended range and accuracy CT required.
10%	100 A	ANSI Spec guarantees only 0.6% accuracy at 10% of rating. Standard CT might provide 0.3% accuracy. Check manufacturer's test data to verify.
100%	1000 A	ANSI Spec guarantees 0.3% accuracy at 100% of rating.
200%	2000 A	Requires extended range, rating factor RF2
300%	3000 A	Requires extended range, rating factor RF3
400%	4000 A	Requires extended range, rating factor RF3

20.4 CT Ratio Calculation Examples

The following examples of installation include

- Typical revenue meter located at a non-generating facility (refer to Example 1).
- A revenue meter located at a generating facility (refer to Example 4).
- An interchange meter located at a point of interchange (refer to Examples 2 and 3).
- An interchange/revenue meter located at a generating facility (refer to Example 4).

20.4.1 Example 1: Revenue Metering

Situation:

- Typical customer service point of metering.
- Metering Voltage: 12.5 kV

- Maximum capacity (bank rating) 25 MVA (1155 A)
- Expected peak load: 10 MW (462 A)

  where

$$\frac{10\ \text{MW} \times 1000}{12.5\ \text{kV}\ \sqrt{3}} = 462\ \text{A}$$

- Estimated minimum load (30% of Peak): 3 MW (139 A). Note that other information may indicate a different minimum.

Metering Requirements:

- MV-90 accessible
- Hourly data retrieved once daily. Certain selected sites may be polled more often.

Discussion:

Based on the maximum transformer capacity of 1155 A, this application will need a CT Ratio of 1200:5. The minimum load of 139 A is greater than 10% of the CT rating. The 1200:5 ratio will serve for future load growth up to the transformer rating. The customer substation would be physically small, minimizing burden problems caused by long CT leads. This application would require a 15 kV insulation rated CT. A standard thermal rating factor of 1.5 is acceptable.

Solution:

This type of installation would typically get a standard meter accuracy 0.3% B1.8 CT with a 1200:5 ratio and thermal rating factor (TRF) of 1.5, Consult manufacturer's data to determine that accuracy is still 0.3% down to the anticipated minimum of 139 A and below.

Options:

For better low end performance, select smaller ratios and specify rating factors of 2 or 3. This tactic is useful in cases where normal loads are light but the occasional contingency load can be large.

20.4.2 Example 2: Interchange Metering – 115 kV

Situation:

- Interchange between BPA and another balancing area.
- Metering Voltage: 115 kV
- Peak Load OUT (BPA to other utility): 100 MW (502 A)

- Peak Load IN (Other Utility to BPA): 75 MW (377 A)
- Minimum Load: Periods when power flow is changing direction: 0 MW (0 A)
- Maximum Capacity (bank or line rating): 150 MVA (753 A)

Metering Requirements: Interchange kW/kWh

- Loss of metering potential alarms
- kVAR and kV analogs are not usually provided by the metering

Discussion:

Interchange loads are bi-directional, meaning that power can flow between utilities in either direction, depending on conditions. Some questions to consider when selecting a CT are the following:

1. Will the load ever reach the rating of the limiting system component during a contingency due to an outage of another facility? (Wide swing of load range that must be accommodated.)
2. Will the load regularly alternate between plus and minus and often hover around the zero point? (Light load performance is an issue.)
3. Will the load be strong in one direction and then switch (seasonally or on/off or because of generation schedules) to be strong in the other direction, with little time at zero? (Light load performance may not be an issue.)
4. How important are near zero readings?

Solution:

Referring to Table 20-1, a CT purchased per the new BPA purchasing standards for 115 kV provides 0.3% or better accuracy from 0.16 MW to 398 MW. This will certainly cover this situation if BPA is supplying the CTs.

If a customer is supplying the CTs and does not wish to follow the BPA example, then there are a series of things to consider.

For the CT to have the capability to cover the bank or line rating of 150 MW (753 A), a CT ratio of 800:5 or 600:5 with RF1.5 would do. If the load will hover around zero, or switch directions often, consider a 400:5 with RF2 for better low end performance. Accuracy at expected load levels must be verified by manufacturer test data. If light load accuracy is extremely important, or if the load swing is extreme, then use of CTs with extended range and accuracy may be required.

20.4.3 *Example 3, Interchange Metering - 230kV*

Situation:

- Similar to Example 2, but with a larger load.
- Interchange between BPA and another balancing area.
- Metering Voltage: 230 kV
- Peak Load OUT (BPA to other utility): 1200 MW (3012 A)
- Peak Load IN (Other Utility to BPA): 800 MW (2008 A)
- Minimum Load: Periods when power flow is changing direction: 0 MW (0 A)
- Maximum Capacity (line rating): 3000 A

Metering Requirements:

- Interchange kW/kWh
- Loss of metering potential alarms
- kVAR and kV analogs are not usually provided by the metering

Discussion:

Interchange loads are bi-directional, meaning that power can flow between utilities in either direction, depending on conditions. Some questions to consider when selecting a CT are the following:

1. Will the load ever go to line rating such as during a contingency due to an outage of another facility? (Is there a wide swing of load range that must be accommodated?)
2. Will the load regularly go bi-directional and often hover around the zero point? (Light load performance is an issue.)
3. Will the load be strong in one direction and then switch (seasonal or on/off or because of generation schedules) to be strong in the other direction, with little time at zero? (Light load performance may not be an issue.)
4. How important are near zero readings?

Solution:

Referring to Table 20-1, a CT purchased per the new BPA purchasing standards for 230 kV provides 0.3% or better accuracy from 0.637 MW to 1593 MW. This will certainly cover this situation if BPA is supplying the CTs.

If a customer is supplying the CTs, and does not wish to follow the BPA example, then there are a series of things to consider.

For the CT to have the capability to cover the load and transmission system rating of 1200 MW (3000 A), a CT ratio of 3000:5A or 2000:5 with RF1.5 would do. If the load will hover around zero, or switch directions often, consider a 1500:5 A with RF2 or 1000:5 A with RF3 for better low end performance. Accuracy at expected load levels must be verified by the manufacturer's test data.

The light load may be a small portion of the maximum load. If light load accuracy is extremely important, or if the load swing is extreme, then use of CTs with extended range and accuracy may be required. In other words, why not use the standard BPA CT?

20.4.4 Example 4, Wind Generation Integration Metering

Situation:

- Metering must be accurate at both the high and low end.
- Metering Voltage: 230 kV
- Maximum Capacity and Peak Load (generation output): 100 MW (251 A)
- Minimum Load: Reverse flow from system to generator during non-generation periods: 0.5 MW (1.25 A)

Metering Requirements:

- MV-90 accessible, hourly data retrieved once daily.
- Interchange kW/kWh
- kVAR and kV analog quantities (possibly)
- Loss of metering potential alarms

Discussion:

Generation at a wind farm varies from the maximum rating of the combined turbines to zero, depending on the wind. Each wind turbine has a parasitic load, and the wind farm has a station service load associated with the interconnecting substation. If there is generation, these loads are self-supplied by the farm.

When generation is zero, the interconnecting transmission system (BPA) back-feeds the generation site to supply the parasitic loads. This sets up a very wide swing between the maximum generation and the back-feed to the loads, both of which need to be measured accurately.

The right to serve the load does not belong to BPA but rather to the local utility, which typically is a BPA customer. When there is reverse flow, the metering point is a delivery point from BPA to the local utility and also a revenue metering point for the utility to bill the generation facility. This makes accurate metering at very low loads essential.

In this example, load ranges from 251 A IN at full generation to 1025 A OUT (back-feed) for zero generation. This places an extreme range requirement on the CT specification.

Based on a load swing of 1.25 A to 251 A primary, this application requires extended range and extended accuracy CTs. Selecting a CT with a CT Ratio of 200:5, an RF 2.0 and extended accuracy of 0.15% will result in accurate metering. The accurate metering range will be 0.5% (1.25 A) to 200% (400 A) of rating.

The generation interconnection substation could be physically large; therefore, burden problems caused by long CT leads must be examined. Refer to Section 13 on Outdoor Cables and Wiring. This application would require CTs rated for 230 kV service.

Solution:

The BPA 230 kV CT per the new purchasing standard would almost satisfy the requirements, but has a slightly higher minimum current rating. Most wind developers metering at 230 kV opt for the solution discussed above: 200:5 A extended range and accuracy.

If metering is done on the 34.5 kV low side of the step-up transformer, a 1500:5 A CT, also with extended range and accuracy, is commonly used.

Options:

The above solution should cover most cases. If different extremes of coverage are needed, adjust the CT ratio and rating factors to get the needed span of accuracy.

21 Technical Application of Voltage Transformers

21.1 Selection of the voltage transformer is based on primary voltage and the maximum volt-ampere burden which may be connected to its secondary at a standard ambient temperature rating above 30°C with a 55°C while maintaining rated accuracy.

21.2 Potential transformers purchased for revenue metering shall be rated as follows:

- 350 kV BIL (69 kV) and below: 0.3% accuracy class at burden W through Z inclusive
- 550 kV BIL (115 kV) and above: 0.3% accuracy class at burden W through ZZ inclusive

21.3 Transformer primary connections should be as follows:

- Electromagnetic type of PT (above 230 kV) should be connected directly to the bus or the line.
- Electromagnetic type of PT (38 kV to 230 kV) should be connected to the bus or the line with expulsion fuse link.
- Electromagnetic type of PT (36 kV and below) shall be protected by a non-expulsion type of fuse.

21.4 Typical potential transformer ratios are listed in the following table.

Table 21-1.—Typical Potential Transformers ratios

θ-θ Voltage	Potential Transformer Ratio
12.5 kV	60:1
13.8 kV	70:1
20.8 kV	100:1
34.5 kV	175:1
69 kV	350:1
115 kV	600:1
230 kV	1200:1
500 kV	2500:1

22 Revenue and Interchange Metering Standards Committee

The information within this document was collected by all members of the Revenue and Interchange Metering Standards Committee. The following members of the Committee created and approved the Guide in accordance with BPA policies and procedures. The members, in alphabetical order, are as follows:

Ken Ballou – SPC Maintenance Engineer

Brent Bischoff – SPC District Engineer

Paul Fiedler – Customer Service Engineer

Bob France – PSC Central

Lois Jane Lugg – SPC District Engineer

Chance Moe – SPC Craftsman

Tommy Ngov – Metering Design and Team Lead

Rich North – Planning Engineer

Ants Realica – Planning Engineer

Minh Ta – Substation Engineer

Steve Trad – PSC Representative and Standards Engineer

Roger Whittaker – Standards

Tom Wolf – Metering Design

Appendix A: Reference Documents

A.1 NERC Documents

The North American Electric Reliability Corporation (NERC**)**. *NERC Standard BAL-005-0-1b–Automatic Generation Control.* Princeton, NJ: 2009 or latest revision.

———. *NERC Standard BAL-006-1.1–Inadvertent Interchange.* Princeton, NJ: 2008 or latest revision.

———. www.nerc.com (a History of NERC and other related documents can be downloaded from the web site). Princeton, NJ: latest revision.

A.2 American National Standards Institute (ANSI) Documents

American National Standards Institute (ANSI). *ANSI C12 Series Standards, Compliance Testing Standard for Utility Industry Metering Communications Protocol Standards* (IEEE draft standard). Washington, D.C.: latest revision.

———. *ANSI C12.20, Electricity Meters 0.2 and 0.5 Accuracy Classes*. Washington, D.C.: latest revision.

———. *ANSI Standard C57.13, Requirements for Instrument Transformers* (IEEE standard). Washington, D.C.: latest revision.

A.3 Institute of Electronics and Electrical Engineers (IEEE) Documents

Institute of Electronics and Electrical Engineers (IEEE). *IEEE Standard 487-2007 IEEE Recommended Practice for the Protection of Wire-Line Communication Facilities Serving Electric Supply Locations*. New York, New York: 2007.

———. *IEEE Standard C57.13.6-2005 IEEE Standard for High-Accuracy Instrument Transformers*. New York, New York: 2005.

A.4 Bonneville Power Administration (BPA) Documents

Bonneville Power Administration (BPA), U.S. Dept. of Energy. *Data Monitoring and Reporting Requirements for Event Recording, Annunciator, and SCADA Systems, a.k.a., Alarm Criteria* (Al_Criteria_rev8.xlw, current document available from BPA Operations Information). Portland, OR: latest revision.

———. *Electromagnetic Interference Policy (EMI).* Portland, Oregon: latest revision.

———. *Grounding Data List* (a substation design document, 2007datlst.xls). Portland, Oregon: 2007. For BPA readers the hyperlink is

http://internal.bpa.gov/sites/sysdata/General%20Documents/2008%20Substation%20Ground%20Data%20List.xls

———. *Requirements for Leased Multi-tone Circuit – Voice Grade* (the Leased Line Technical Specification is available on the TECT Telecommunications Design SharePoint website).Portland, OR: latest revision.

———. *Substation Engineering Policy for Conduit Systems* (the EPADS document d2conpol.doc). Portland, OR: latest revision.

———. *Technical Requirements for Interconnection to the BPA Transmission Grid*. Portland, Oregon: Latest revision.

A.5 Superseded Documents

Bonneville Power Administration (BPA), U.S. Dept. of Energy. *Substation Engineering Policy for Revenue Metering* (the EPADS document d2revmtr.doc, which has been superseded by this guide). Portland, OR: latest revision.

———. *Substation Engineering Policy for Instrument Transformers* (the EPADS document, d4instra.doc). Portland, Oregon: latest revision.

Appendix B: Standard Drawings

All drawings listed below refer to the latest revisions of Standard Drawings published by Bonneville Power Administration (BPA), U.S. Dept. of Energy (Portland, OR).

Item	Drawing No. and Sheet No.	Title
1	Drawing 274159, sheet 1	230/115/69/34.5/14.4kV – 120V Revenue Metering Junction Box Wiring
2	Drawings 280707, sheet 1	Standard Block Diagram, Large Generation Integration Metering
3	Drawings 280708, sheets 1, 2, 3	Standard Layout and Wiring, Large Generation Integration Metering
4	Drawings 280415, sheet 1	Standard Block Diagram, Small Generation Integration Metering and Telemetering
5	Drawings 280416, sheets 1, 2, 3	Standard Layout and Wiring, Small Generation Integration Metering and Telemetering
6	Drawings 281317, sheet 1	Standard Block Diagram, Revenue Metering (land line)
7	Drawings 281316, sheets 1, 2, 3	Standard Layout and Wiring, Revenue Metering (land line)
8	Drawing 283966, sheet 1	Pole Mount Meter Standard Block Diagram
9	Drawing 283967, sheet 1	Standard Layout and Wiring, Pole Mount Metering
10	Drawings 183257, sheets 1, 2	EPADS Schematic Diagram, Relay Circuits
11	Drawing 271019, sheet 1	EPADS Assembly diagram, 115/230kV Junction Box Layout
12	Drawing 274159, sheet 1	EPADS Installation, 230/115/69/34.5/15kV – 120V Revenue Metering Junction Box Wiring
13	Drawing 287767, sheet 1	Standard Block Diagram, Revenue Metering (cell phone)
14	Drawing 287766, sheets 1, 2, 3	Standard Layout and Wiring, Revenue Metering (cell phone)