



Metering Application Requirements STD-DC-000005 REVISION 06

Standard/Technical Content Owner: TEEL

DISTRIBUTION STATEMENT: Approved for public release

This document and its contents are to be controlled when obtained external to the Bonneville Power Administration (BPA) or its assigns. Do not reproduce or distribute.

This standard is a continually evolving document that may change without notice. It describes material, standards of quality, and requirements that are applicable to BPA planning, design, maintenance, and construction projects, and it was developed to serve and support BPA's electrical transmission system and infrastructure. Therefore, the requirements presented within may not be compatible with any other electrical utility's system or infrastructure.

TABLE OF CONTENTS

1. INTENT	2
2. CURRENT REVISION	2
3. DEFINITIONS, ACRONYMS, AND ABBREVIATIONS	2
3.1 Definitions	2
3.2 Acronyms and Abbreviations	6
4. BACKGROUND	6
5. STANDARD EXCEPTIONS	7
6. POLICY AND APPLICATION	7
6.1 General Meter Requirements	7
6.2 Revenue Metering	10
6.3 Meter Data Collection Communication	10
6.4 Interchange Metering	13
6.5 Generation Metering	15
6.6 BPA Data Sent Through SCADA	16
6.7 Exchanging Data with Customers	18
6.8 Polarity Convention	19
6.9 Instrument Transformers	21
6.10 Testing and Calibration	34
7. REFERENCES	35
7.1 Associated Design Templates Drawings	36

Figures

Figure 1.--- Calculating Total Overall Meter Error	7
Figure 2.--- Typical Revenue Metering Application	10
Figure 3.--- Typical Interchange Metering Application	14
Figure 4.--- Typical Generation Metering Application	16
Figure 5.--- Revenue Metering Power Flow Diagram	20
Figure 6.--- Revenue Metering Polarity Convention	20
Figure 7.--- Interchange Metering Polarity Convention	21
Figure 8.--- Generation Metering Polarity Convention	21
Figure 9.--- CT and VT Secondary Outdoor Connections	24
Figure 10.--- VT Meter and Relay Secondary Outdoor Connections	24

Figure 11.--- CT and VT Secondary Indoor Connections	25
Figure 12.--- Typical Test Switch.....	26

1. INTENT

The purpose of this standard is to enable Bonneville Power Administration (BPA) to provide a single application document 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. BPA expects customers to follow the intent of this metering guide as required by their customer contract.

This standard 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 voltage transformer requirements for metering, and all associated ownership, maintenance and testing issues of such meters.

This standard applies to both new and revised metering installations. Existing meter installations are grandfathered under previous standards and BPA will evaluate on a case-by-case basis, as necessary.

This standard will be revised as technologies change.

This document is owned and maintained by Substation Engineering at BPA.

2. CURRENT REVISION

Revision 06, 9/24/2024: Targeted Revision: Updated to specify PT's secondary voltage to be 120VAC when using VAC power. Affects Section 6.1.3.

For historical information on what has changed in all previous revisions or updates to this standard, please refer to the background document.

3. DEFINITIONS, ACRONYMS, AND ABBREVIATIONS

3.1 Definitions

Area Control Error (ACE): The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

Automatic Generation Control (AGC): A system that measures instantaneous loads at interchange points (boundaries with adjacent control area) and adjusts generation to follow load. It consists of continuous, instantaneous (i.e. real-time) load signals (kW), telemetered to AGC computers at a transmission control center.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.

Balancing Authority Area (BAA): The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Capacitor Voltage Transformer (CVT): Secondary voltage is obtained by voltage dividers in the capacitor stack between the line and ground.

Critical Infrastructure Protection (CIP): An effort to improve the North American power system's security. These efforts include standards development, compliance enforcement, assessments of risk and preparedness, and the dissemination of critical information and raised awareness regarding key security issues. NERC's standards for governing critical infrastructure apply to entities that "materially impact" the reliability of the bulk power system.

CT Burden: The CT secondary circuit impedance. For metering, this is the one-way wire impedance plus the meter AC current input burden. The CT secondary burden is predominately resistive. CT burden ratings are typically B0.1, B0.2, B0.5, B1.0, and B1.8. 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 secondary current is operating outside the rated accuracy range. Items that contribute to the burden of a current circuit are test switches, terminal blocks, intermediate conductors and meters. The most common source of excess burden in a current measurement circuit is the conductor between the meter and the CT.

CT 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 IEEE specification C57.13. When high 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.

CT Extended Range: Extended Range is operating beyond the normal IEEE 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 CT 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 ($1200 \text{ A} \times 0.005 = 6 \text{ A}$).

CT Rating Factor (RF): Also known as the CT Thermal Rating Factor or TRF is a number by which the nominal full load current of a CT can be multiplied to determine its absolute maximum primary current, maintain accuracy, and without exceeding the allowable temperature rise at a defined ambient temperature. For example, a 1200:5 CT with a TRF or RF of 3 could operate at the maximum 3600 A primary, which would produce 15 A in the CT secondary.

Current Transformer Ratio (CTR): Current transformer ratio of primary amps to secondary amps, such as 1200:5A.

Customer Contract: A contract between BPA and the customer that describes the duties and responsibilities of each party. Types include any contract to which BPA is a party, with the exception of Environment, Fish & Wildlife, Real Property, Supply Chain and Procurement Agreements.

Dial Automatic Telephone Switching (DATS): This is BPA's internal phone system operating over BPA communication circuits.

District Data Concentrator: This is a BPA communication device that exchanges information between remote sites and the control centers. Typically, there is one Data Concentrator per district.

Electric Industry Data Exchange (EIDE): A communications protocol for data exchange between control centers.

Generation Metering: Generation 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.

Ground Potential Rise (GPR): The voltage increase on some grounded object, or at some ground location, relative to a distant grounding point referred to as remote earth (zero-potential), due to current flowing through the earth between the two locations, to or from the grounded object.

Instrument Transformers (current and voltage): A transformer used to reduce the actual line currents and voltage to levels appropriate for operation indications, metering and control.

Interchange Metering: Interchange metering measures power crossing the boundary between BPA's Balancing Authority Area and another Balancing Authority Area.

Isolation: BPA meter analog or pulse outputs provided to on-site customers may be physically and electrically isolated from BPA equipment using appropriate isolation devices.

Magnetic Voltage Transformer (MVT): Copper wound around a steel core which is inductive by nature. They are used to provide a secondary signal that is proportional to the actual prevailing primary value. The secondary signal supply instruments, meters, relays and other similar devices.

Meter Data Collection (MDC): This term refers to BPA's billing data collection system. BPA used MV-90 to collect this billing data from meters until the year 2020. Now Primestone fulfills the same function as MV-90 for BPA.

The MDC is a translation system which interprets a variety of metering communication protocols used for data collection and analysis. BPA's MDC can poll interval pulse counts from recorders or meters, perform validation, editing, reporting and historical database functions.

Meter System: A metering system includes the instrument transformers, meter, terminal blocks, test switches, and communication equipment at the site.

MV-90™: The Multi-Vendor Translation System interprets a variety of metering communication protocols used for data collection and analysis. Data is retrieved over network or telephone lines by MV-90™. In addition to polling raw pulses from the recorders, MV-90™ can perform data validation, editing, reporting and historical database functions. MV-90 was first introduced in 1990, hence, the "90."

North American Electric Reliability Corporation (NERC): The North American Electric Reliability Corporation (NERC) is a not for profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards, annually assesses seasonal and long-term reliability, monitors the bulk power system through system awareness, and educates, trains, and certifies industry personnel.

Parasitic Load: All electrical power required by a generating facility for internal operation. These loads, sometimes referred to as “Station Service”, subtract from the gross generator output during generation, and must be supplied externally (often by back-feed from the connected transmission system) when there is no generation. These loads vary, depending on the status of the generation facility, such as when the generation is idle, preparing to operate, in the process of start-up or is generating.

Revenue Metering: Revenue Metering is used at points of electrical connection with BPA customers to measure demand and energy for providing a bill to the customer. Typical installations require 5 minute kWh IN and OUT, and kVARh IN and OUT data for billing purposes. BPA’s MDC is used to collect Revenue Metering data.

Revenue Metering System (RMS): RMS is the generic term used by BPA to describe the collection of data from Revenue Metering. RMS can refer to both the remote devices as well as the Metering Data Collection (MDC).

RMS Access Agreement: An RMS Access Agreement is an agreement in which BPA allows the customer direct access to the Revenue Metering System (RMS) meters/recorders at select sites, subject to certain restrictions. A BPA customer can access RMS data for their delivery points directly from the remote meter/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.

Station Service Load: The electrical power required by the customer's Interconnection Facility equipment loads.

Supervisory Control and Data Acquisition (SCADA): SCADA consists of local SCADA RTUs at substation sites; SCADA Masters are located at Dittmer Control Center and the Munro Control Center.

SCADA RTUs provide remote control and monitoring of substation power system equipment. Power system equipment quantities are developed by transducers or metering equipment and provided to the substation SCADA RTU. The SCADA Master polls substation RTUs every 2 seconds.

Telemetry: is the transfer of analog and digital data from one location to another. The data is typically “real-time” using high-speed communication systems such as microwave radio or fiber. Telemetry for AGC is the transfer of continuous instantaneous (i.e. real-time) kW load or generation data to the AGC system through the SCADA system.

Voice over IP (VoIP): Technology that allows telephone calls to be made over computer networks like the Internet. VoIP converts analog voice signals into digital data packets and supports real-time, two-way transmission of conversations using Internet

protocol rather than by traditional circuit transmission of the Public Switched Telephone Network (PSTN).

Voltage Transformer (VT): A device used to create a secondary voltage signal smaller than and in proportion to the voltage existing on a high voltage circuit.

3.2 Acronyms and Abbreviations

ACB: Air circuit breaker

CT: Current transformer

IP: Internet Protocol

NIST: National Institute of Standards and Technology

RTU: Remote Terminal Unit

4. BACKGROUND

Within the Northwest, Bonneville Power Administration meters load, generation, and interchange boundaries. Accurate metering of electricity generated or consumed provides key inputs for billing and settlement purposes. Direct measurement of generation and interchange with telemetry allows BPA to manage and control power generation in real-time to balance the system.

BPA also meters a wide diversity of customers from publicly owned utilities to independent power producers. The existing metering systems, new and old, are adapting to a changing market that requires a higher level of support with higher resolution (5 minute) and increased access to data.

To meet both reliability and industry technical standards, this standard describes the requirements needed by BPA to limit billing revisions for our customers and to achieve accurate and reliable metering.

Some additional resources that provide context for this standard are:

- STD-MC-R00003, AGC – Interchange MW Metering Common Source Verification Test Standard
- STD-MC-R00010, Revenue Metering Maintenance Standard
- STD-DS-000003, Outdoor Conduit Systems
- STD-DS-000021, Electromagnetic Interference (EMI) Mitigation Practices
- IEEE 487, Recommended Practice for the Protection of Wire-Line Communication Facilities Serving Electric Supply Locations
- Substation Ground Data List
- The North American Electric Reliability Corporation (NERC). www.nerc.com (a History of NERC and other related documents can be downloaded from the web site). Princeton, NJ.

5. STANDARD EXCEPTIONS

Any deviation from this standard must be requested and submitted in accordance with STD-P-000002, "Standard Compliance and Exception Policy."

6. POLICY AND APPLICATION

For power system metering, the division of responsibility, and financial terms and conditions must be specified in an agreement between BPA and the customer. Even if no money is changing hands a Customer Contract must be negotiated and executed to ensure both parties understand their obligations and to document the agreement.

6.1 General Meter Requirements

BPA's current standard meter is the SEL-735 for revenue, generation, and interchange metering applications.

Meters must be microprocessor-based, bidirectional and meet or exceed ANSI C12.20-2015 standards for 0.1% accuracy class. Meter inputs are derived from instrument transformers secondary circuits. Each meter must have the ability to measure three-phase, two- and three-element metering, and record at least bidirectional kilowatt-hours (kWh) and kilovolt-ampere reactive hours (kVARh) load profile data.

Meters must be able to provide data accumulated over a time interval, both 5-minute interval data for billing and 1-hour interval data for energy accounting. For 1-hour interval data, the meter must freeze the counters at the top of each hour. Meters must be able to store all accumulated data for 45 days minimum.

The meters must be able to provide data to a variety of users. Meters must be accessible by BPA's Meter Data Collection (MDC) software, formerly known as MV-90, for data retrieval via an internal dial-up modem, through an RS-232 port, or via an Ethernet IP port. There must be at least one additional serial or Ethernet port that supports DNP3.0 or Modbus for communication to SCADA. There must be at least three analog outputs and four digital outputs per meter in order to share data with a customer.

BPA requires that the overall metering accuracy error not to exceed $\pm 1\%$. This accuracy includes instrument transformers, meters, and data conversion. The Gaussian distribution method for total system error will be used.

$$\text{Total System Error} = \sqrt{\text{ECT}^2 + \text{EVT}^2 + \text{EMT}^2 + \text{EDT}^2}$$

ECT = current transformer percent error

EVT = voltage transformer percent error

EMT = meter percent error

EDT = data conversion percent error

Figure 1.--- Calculating Total Overall Meter Error

Meters must be located inside a climate-controlled permanent building or inside the cabinet used for outside pole or structure-mounted applications from BPA's cabinet meter template (see section 7.1).

6.1.1 *Ownership and Maintenance*

BPA design and construction standards will be followed for all BPA-owned metering. This is to ensure accuracy, reliability, reduced cost, and faster maintenance response.

BPA will own and maintain all metering equipment in BPA facilities. BPA requires physical access to BPA-owned meters and related equipment in customer facilities. Details of shared locks or other requirements to obtain means of unescorted access shall be defined in the Customer Contract.

The customer will be invited to witness all BPA-owned meter testing. BPA will furnish copies of test data and reports to the customer if requested.

The customer, as specified in a Customer Contract, may be granted permission to purchase, install, maintain, and own the metering system located in their facility. BPA will require that the meter be maintained and tested to BPA maintenance and testing 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 customer upon approval.

For customer-owned 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 in advance of installation.

6.1.2 *Loss Compensation*

BPA meters are not internally adjusted for losses. Any necessary loss compensation is factored into a specific loss adjustment in BPA's Agency Metering System. Loss adjustments are calculated using the physical characteristics of electrical facilities located between the contracted point of delivery and the point of metering specified in the Customer Contract. Customer cooperation is required to obtain any customer-owned transmission line characteristics and/or manufacturer's factory test reports of power transformers and voltage regulators. BPA Customer Service Engineering performs loss adjustment calculations and provides them to the customer for review before implementation.

6.1.3 *Power Requirements*

A BPA metering system can be 125 VDC or 120 VAC powered. When the meter rack is 120 VAC powered there is an automatic throw-over scheme that will transfer meter power to the A-phase voltage transformer during a loss of station service power. The A-phase voltage must be 120VAC for the meter to be powered. Therefore, when using 120 VAC power, the VT must be properly sized to accommodate the burden and the specification of the metering equipment.

Generally, metering equipment installed in a customer substation is 120 VAC powered and metering installed in a BPA substation is 125 VDC powered. If any metering system equipment can only be powered via AC or DC, then the preference is to power all the

equipment from that power type to avoid having to bring both AC and DC power into a meter rack.

6.1.4 *Customer Sites*

The following defines the requirements for BPA owned and maintained meters installed at a customer site:

- A Customer Contract shall be executed between BPA and the customer prior to the design and installation of the metering system.
- The meter must be designed per BPA standards and documented in an Ownership, Operations, and Maintenance Customer Contract.
- BPA requires a set of drawings that document the installation of the meter. The set of drawings should at least include a one line, schematics, and wiring. The drawings will be stored in BPA's file management system.
- BPA's preference is to have the metering systems installed in a standard BPA rack located inside a building. Customer shall provide indoor rack space. A standard BPA meter rack is 610 mm (24.0") wide, 483 mm (19.7") deep, and 2200 mm (86.6") tall. It requires a minimum of 36" of front and back access. Cable access can be from the top or bottom. As an alternative, BPA meters can be located in the outdoor cabinet used for pole- or building-mounted applications per BPA's cabinet revenue meter template (see section 7.1).
- Feed AC or DC rack power from a dedicated 20 Amp circuit.
- For revenue-only metering where the requested schedule is accelerated or BPA resources are limited, BPA may permit the customer to design, procure, and install the metering system; or install a BPA pre-built meter panel or cabinet and give ownership and maintenance to BPA. BPA will supply the customer with a meter drawing template and bill of material. The customer shall provide final as-built drawings in Microstation or CAD format, and send to BPA's Substation Engineering Design department. Any deviation from the design template or bill of material will need BPA approval prior to issuing for construction.

6.1.5 *Security*

BPA-owned meters will be installed in a secured area with controlled access, allowing only those personnel with a need to access the meters. If the meter is to be installed in an unsecured area, the meter will be installed in a locked cabinet.

6.1.6 *Validation of Meter Data*

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

Where applicable, revenue data may be checked against SCADA data for validation.

For interchange metering, hourly kWh data shall be shared with Adjacent Balancing Authorities via the Electric Industry Data Exchange (EIDE). If hourly kWh is being gathered by the customer using another method in addition to EIDE, then EIDE will be the trusted source.

BPA retrieves and validates all revenue meter data per BPA Policy 483-1 Revenue Quality Meter Data Management.

6.1.7 *GPS Clock*

All BPA interchange and generation metering requires a BPA GPS clock to keep the meter time accurate.

6.1.8 *Cyber Security*

For systems which include cyber assets, a System Security and Compliance Plan shall be developed to address applicable requirements of the Federal Information Systems Management Act (FISMA) and NERC Critical Infrastructure Protection (CIP).

6.2 Revenue Metering

Revenue Metering is installed at the location where the energy is metered between BPA and a customer for billing or settlement. Hourly or sub-hourly interval data is collected by BPA's MDC.

Revenue customers are typically billed on two factors:

- Total energy (kWh) used during the billing period. Total kWh is the summation of each hourly-recorded kWh quantity during the period.
- Demand (kW). Demand is the rate of power usage. Peak demand determines required system capacity.

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

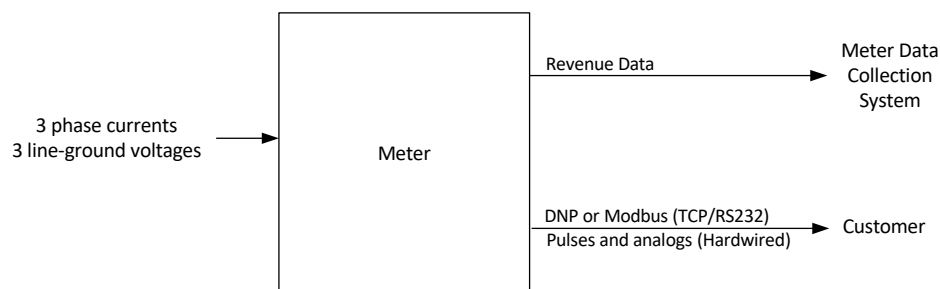


Figure 2.--- Typical Revenue Metering Application

6.3 Meter Data Collection Communication

BPA's MDC is a multi-vendor interval data collection system that BPA uses to collect 5-minute interval kWh and kVARh energy counters, instantaneous phase-to-ground voltage values, and/or voltage alarms from the meters. Data collected by the BPA MDC is used for billing, settlement, and/or scheduling purposes. BPA's MDC will call each meter either hourly or daily to collect the 5-minute interval data, set time in the meter (revenue-only meters), and monitor time drift. Revenue quality metering data is stored in BPA's Agency Metering System and is available to customers through the Customer Portal.

There are a number of communication options available for BPA's MDC to communicate to metering devices. Here are the options listed in order of preference:

- Public Internet: cellular gateway. BPA will own and maintain the cellular equipment at the substation. This has proven to be the simplest to install and the most reliable communication path to our metering systems. It requires cellular coverage in the area.
- Public Internet: customer network or public internet connection. BPA is dependent on the customer or public internet provider to keep this communication path operational. The field needs to know who to contact when the internet connection stops working.
- Land Line (PSTN/POTS). Excluding voice over IP (VoIP). This can be a good option when there is no cellular coverage. Land lines tend to be less reliable than a cellular gateway and require working with the local phone companies when the communication path fails or degrades. This option may require installing a line-sharing switch when a substation handset or other devices are sharing the phone line.
- Serial circuit extension. This option is useful when a meter is located in a station without cellular reception and the cost to install a land line is high. The meter is connected through a serial circuit to a remote site within the same district with cellular reception where a cellular gateway can be installed. The serial circuit will likely require fiber installed between the meter and remote sites.
- BPA network (BUD). BPA's MDC does not have access to the BUD network for meter data collection.
- BPA's private telephone system (DATS). This option is no longer available. Existing DATS connections are in the process of being moved.

Note: if a meter is being replaced and there is an existing land line with no history of complications, BPA may opt to keep MDC communications through the existing land line rather than moving to an internet connection.

For direct customer MDC access to the meter see section 6.7.5.

MDC communication over telephone and by network to a meter providing control signals (AGC) is considered connectivity to a critical cyber asset and is not allowed. Therefore, when a meter is required to provide both revenue and control data, BPA offers the following options:

- Install two meters for the single metering point, with one meter for AGC quantities and the other meter for MDC, or
- Install a recording device that will count hardwired pulses and communicate with the MDC.

6.3.1 *Cellular Public Internet*

Public Internet connections to meters are most commonly provided by cellular data gateways. There are several advantages to choosing digital cellular data service over

telephone, including ease of installation and isolation from the effects of Ground Potential Rise (GPR). One advantage to digital 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.

Digital cellular hardware at the site must support a serial or ethernet connection to the meter and must convert data between serial and IP across the public internet.

6.3.2 *Customer Public Internet*

For BPA to receive MDC data from a meter over a customer IP network:

- The customer's network must have public internet access.
- For non-VPN connections, the customer shall provide a solution through their firewall to allow BPA's public IP addresses to reach the meters and provide the meter IP address and TCP port number. BPA can only use a certain range of TCP port numbers, so the customer shall accommodate BPA's TCP port number requirements (usually in the 3000s).
- For VPN network connections the customer will provide the path using the public internet and work with BPA's server access team for installations.

6.3.3 *Direct Public Internet*

For BPA to receive MDC data from a meter using a direct public IP connection, BPA will install a serial port server in between the meters and the public internet to provide access control and encryption.

6.3.4 *Public Switched Telephone Network (PSTN)*

When using a PSTN metallic telephone line, proper GPR protection is required. See STD-DC-000038 Telecommunications High Voltage Protection Policy. The owner of the facility is typically responsible for the cost and installation of GPR protection equipment.

BPA dials out for meter query using a bank of standard public telephone modems. While a standard land line telephone service at the meter end will work, using VoIP at the meter end causes communication problems and is not a BPA approved option due to bandwidth limitations on most networks. VoIP is not specified to support analog telephone modems.

The owner of the facility is typically responsible for making the arrangements and paying the cost for installation and monthly charges.

6.3.5 *BPA's Network (BUD)*

MDC does not have access to the BUD network for meter data collection.

6.3.6 *DATS*

The DATS is BPA's private telephone system. It is designed for voice communications and is not intended for data use. Starting in 2021 no meter will be accessed through the DATS system.

6.3.7 *Meter Data Collection Communication Responsibilities*

For dedicated network solutions, the meter owner is the preferred owner of the communications equipment.

6.4 Interchange Metering

Interchange Metering is required where BPA has a Tie-Line, Pseudo-Tie, or Dynamic Schedule with an Adjacent Balancing Authority Area. BPA typically gathers instantaneous (also referred to as “real-time”) Watt (kW) and VAR (kVAR) analogs, hourly kilowatt-hours (kWh), and 5-minute kilowatt-hour (kWh) data from interchange metering. The meter owner supplies this data. The instantaneous kW analog quantity is supplied to both Balancing Authority AGC systems. The hourly kWh collected at the top of each hour is used for schedule verification and kW analog accuracy checks. The meter energy demand interval 5-minute registers are pulled by the BPA MDC. This data is used by BPA as the EIM Entity and Scheduling Coordinator Metering Entity for settlements in the Western Energy Imbalance Market (EIM). Refer to STD-N-000001, Technical Requirements for Interconnection to the BPA Transmission Grid for data requirements.

If the meter is customer-owned, the customer shall provide hourly kWh data to BPA through the EIDE link (control center to control center). AGC data will be provided to BPA either via hardwired data or via DNP3 to an on-site BPA SCADA or district data concentrator. If redundant meters are used, the customer/adjacent BA will switch between meters A and B; BPA will receive AGC data from whichever meter is primary. To access the 5-minute energy demand interval data, the meter must have an additional serial port, Ethernet port, or internal modem for data retrieval by BPA’s MDC.

Interchange metering design must conform to the NERC Standard BAL-005-1, “Balancing Authority Control” that establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirements for acquisition of the data and for providing the information to the System Operator.

From R7: Each Balancing Authority shall ensure that each Tie Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with:

- 7.1 a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE (Area Control Error); and,
- 7.2 a time synchronized common source to determine hourly megawatt-hour values agreed upon to aid in the identification and mitigation of errors.

In general terms this NERC standard stipulates 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. The method of obtaining data from the common metering source (i.e. via protocol or hardwired) may differ between both Balancing Authorities.

BAA to BAA Net kW power flow is used to calculate the Area Control Error that drives Automatic Generation Control in real-time.

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 (by calculation, not by applying compensation settings to the meter) to the actual point of interchange. There shall be no intervening transmission tap points.

6.4.1 Ownership and Maintenance

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

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

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

The balancing authority's meter shall be the official meter of record for interchange and billing data. Billing data may come from separate meters if the instrument transformers are in an electrically separate location to fulfill billing requirements.

The meter owner must coordinate any meter changes with the other balancing authority prior to the change. The adjacent balancing authority shall notify BPA customer service engineering of plans to modify interchange metering at least six months prior to making any changes.

6.4.2 Typical Interchange Metering

Figure 3 shows the typical interchange metering set up. See design template for more information (Section 7.1).

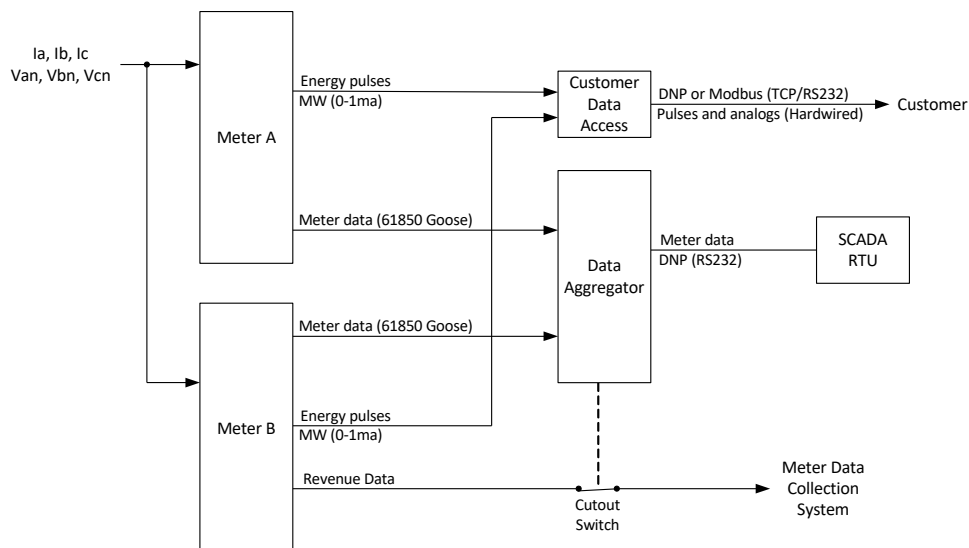


Figure 3.--- Typical Interchange Metering Application

6.5 Generation Metering

Generation metering is required when a generation facility is connected to the power system inside BPA's balancing authority. Most often generation metering is owned and maintained by BPA.

BPA typically gathers instantaneous Watt (kW) and VAR (kVAR) analogs, hourly kilowatt-hours (kWh), and 5-minute kilowatt-hour (kWh) data from generation metering. The instantaneous kW analog quantity is used in BPA's AGC system. The hourly kWh collected at the top of each hour is used for schedule verification and kW analog accuracy checks. The BPA MDC gathers the meter energy demand interval 5-minute registers, which BPA uses for billing purposes, and as the EIM Entity and Scheduling Coordinator Metering Entity for settlements in the Western Energy Imbalance Market (EIM). Refer to STD-N-000001, Technical Requirements for Interconnection to the BPA Transmission Grid for data requirements.

Generation metering is often 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.

Generation Integration Metering can be installed either at the generation site or, in the case of a dedicated transmission line, from the generation site to the transmission system.

6.5.1 *Ownership and Maintenance*

With BPA approval, and in accordance with BPA specifications and configuration, the host utility may install the generation metering in a non-BPA site. In these cases, BPA issues a design drawing package, inspects and tests the completed installation, and then takes ownership, operation and maintenance responsibility of the metering. The meter installer will redline the drawing package and send it to BPA. The drawings will be stored in BPA's drawing management system.

For small generation metering that requires 5 minute demand data only, the customer has the option of purchasing, installing, maintaining and owning the metering system. The meters must be accessible by BPA's MDC software for data retrieval via land line and internal dial-up modem or cellular modem.

6.5.2 *Typical Generation Metering Application*

Figure 4 shows the typical generation metering set up. See design template for more information (Section 7.1).

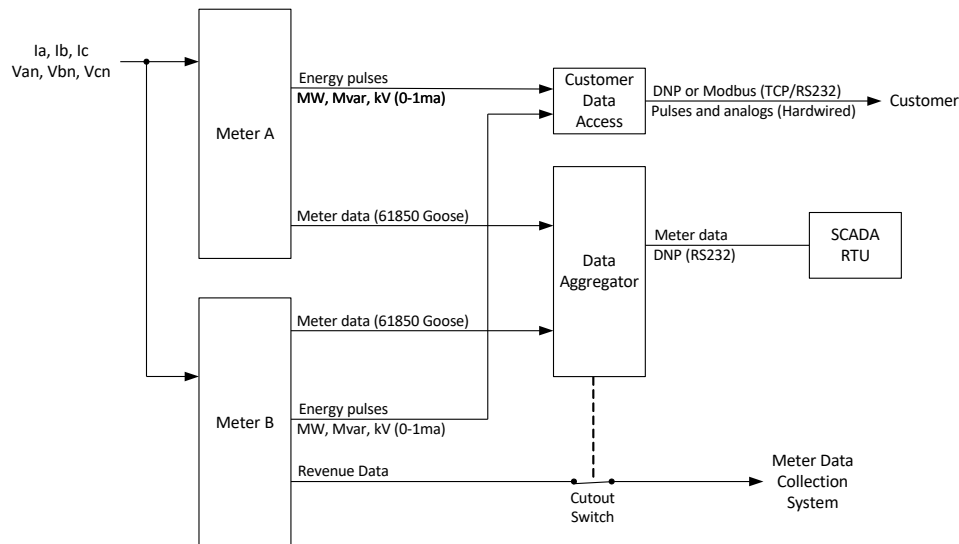


Figure 4.---Typical Generation Metering Application

6.6 BPA Data Sent Through SCADA

BPA interchange and generation meters provide alarms, analogs, and counters to a district data concentrator or on-site DNP master capable Substation RTU using DNP over serial (RS-232).

For Table 1 below, see STD-N-000001, Technical Requirements for Interconnection to the BPA Transmission Grid for more information on telemetry requirements for various MW thresholds.

Table 1.— AGC/Hourly kWh Data Collection: Use this decision matrix when installing a BPA-owned meter

Interchange or Generation Metering Size	Site Owner	Substation RTU Type	Data Polled By
Small (no telemetry required)	BPA or Customer	N/A, no AGC data needed	N/A, no AGC data needed
Small (telemetry required)	Customer	Not DNP Master Capable	District data concentrator with DNP master capability.
	Customer	None	District data concentrator with DNP master capability.
	BPA or Customer	DNP Master Capable	Substation RTU
	BPA	Not DNP Master Capable	District data concentrator with DNP master capability until substation RTU is replaced.
Large	Customer	Not DNP Master Capable	Install substation SCADA RTU with DNP master capability.
	Customer	None	District data concentrator with DNP master capability.
	BPA or Customer	DNP Master Capable	Substation RTU
	BPA	Not DNP Master Capable	Replace substation RTU with DNP master capability.

Communication circuit options include fiber, radio, and leased lines. Leased lines may require the same GPR protection as a PSTN. The Communications Planning group will identify the circuit in a Project Requirements Diagram (PRD).

The BPA SCADA master is set to poll data from each substation SCADA RTU every 2.0 seconds. Substation RTUs or district data concentrators will be set to poll data from each customer RTU or meter every 1.0 second. When the customer is passing data to BPA, the customer RTUs polling data from meters will be set to poll the data every 1.0 second.

6.6.1 *Hourly kWh Data*

A station RTU or district data concentrator polls BPA-owned interchange and generation meters for hourly kWh and kVARh counters. The SCADA master then polls the station RTU or district data concentrator for those counter values. Lastly, Energy Accounting polls the SCADA master for the counters shortly after the end of each hour interval. For the hourly kWh data register, 1 MWh = 1 count and Energy Accounting is limited to reading a 7-digit register. Historically the hourly kWh demand data was polled by BPA's kWh Master using DNP3 over a dedicated RS-232 communication circuit. The kWh Master is no longer accepting any new connections.

When BPA owns and maintains the official meter for the interchange or generation metering point, the value collected and adjusted by dispatch is the official kWh value of record. The owner of an interchange meter is required to collect the kWh data at the top of each hour and send it to the adjacent balancing authority within five minutes after collection. BPA control center sends this official value to other balancing authorities via EIDE.

For BPA metering, there is no physical cutout for hourly kWh at the meter site. Instead, to cutout kWh for a meter, a person needs to be on-site with the meter system and to use the pushbutton on the front of an AGC-only meter or, for redundant meters, the pushbuttons on the front of the meter aggregator to send a kWh cutout alarm to the BPA control centers. When the control centers receive this alarm, their software will flag the data as inaccurate. BPA is reading hourly kWh from both meters simultaneously when metering is redundant.

6.6.2 *AGC Analog Values*

Instantaneous kW data is used for Automatic Generation Control (AGC). This AGC data is collected by the control center from interchange and generation meters. The AGC data must be updated every 6 seconds maximum. This kW data allows the AGC software to automatically send generation adjustment requests in real-time to generation sites to balance generation with load. Direct interchange and generation meter connections are the primary sources for AGC. SCADA transducers and ICCP values are used as back-up sources only.

AGC kW is polled via a station RTU or district data concentrator. That data is then polled by the SCADA master, where it is passed to the AGC system.

For redundant BPA-owned meters, a software selector switch will determine whether meter A or meter B is sending kW to BPA for AGC. During normal conditions, meter A will provide the analog AGC quantity and meter B will be accessed by the BPA MDC for

energy interval data retrieval. In the event that meter A is out of service, meter B will provide the analog AGC quantity and the BPA MDC data retrieval access will be disabled.

AGC watt quantities come from revenue meters or metering accuracy transducers (+/- 0.5% of full scale) that are connected to metering accuracy current transformers (+/- 0.3%) and metering accuracy voltage transformers (+/- 0.3%).

6.7 Exchanging Data with Customers

BPA offers control center to control center, web portal, and direct meter system access to allow data sharing with customers. The options available depend on both the type of data to be exchanged and the type of metering system. Any request to access meters directly shall be made to BPA's Customer Service Engineering and are subject to approval.

BPA can share data between control centers using EIDE and/or SCADA ICCP; no other control center to control center options are available.

For sharing data directly from BPA metering systems, data may be provided to the customer/adjacent balancing authority using DNP3 or hardwired outputs. Alternative transducers can provide data access methods not provided by BPA's standard installation; however, data so obtained can be used for indication only. Billing/5-minute interval data can be obtained via BPA's web portal.

Where BPA does not own the metering, the adjacent balancing authority or utility shall provide data to BPA. The data shall be provided via hardwired analog outputs from the meters, DNP3 over serial, or Modbus over serial to an on-site BPA SCADA RTU or to the district data concentrator.

BPA Planning will identify the exchange of data requirements in the PRD and/or agreement as applies.

6.7.1 EIDE (*Electric Industry Data Exchange*)

BPA will use EIDE protocol to exchange hourly kWh between adjacent balancing authorities. EIDE is an XML-based communication protocol developed by the WECC Western Interconnection Tool working group. Per section 6.1.6, EIDE is the trusted source for interchange metering hourly kWh.

6.7.2 SCADA ICCP (*Inter-Control Center Communication Protocol*)

SCADA ICCP (ICCP) is used to exchange data (Watts, VARs, voltage, and equipment status) between control centers. ICCP is carried on private network circuits only. BPA does not allow ICCP as their primary source of telemetry for interchange instantaneous MW.

6.7.3 DNP3 (*Distributed Network Protocol V3.0*)

DNP3 is used to share kW, kVAR, kVOLT, kWh IN, kWh OUT, kVARh IN, and kVARh OUT data directly from a BPA meter system. BPA offers DNP3 data collection options for each type of metering system. For the redundant system, both meters send data via hardwired signals to an SEL-2411. The customer accesses the data via DNP3 over serial or DNP3 over TCP. The SEL-2411 switches data between meters A and B per a

manual switch operated by field personnel. Pulses are counted in the SEL-2411 using 1-65000 counters. These counters can be frozen and read by the customer.

For small generation/interchange meter systems (single AGC meter), the customer/adjacent BA can access the meter data directly via DNP3 over serial. DNP3 over TCP is not available per BPA policy.

For revenue-only meter systems, the customer can access the meters directly via DNP3 over serial or TCP.

6.7.4 *Hardwired*

BPA's SEL-735 meter systems can provide up to seven different KY digital output values and four 0-1 mA analog outputs. If meters are redundant, pushbuttons on the front of the SEL-2411 meter aggregator are used to switch quantities between meter A and B. The pushbuttons control output contacts that activate or deactivate the coils of terminal block relays. The terminal block relays are made to switch data signals in/out of service.

KYZ outputs are available and require the addition of repeat relays to translate the meter's KY outputs to KYZ.

If the analog or pulse out wires between a BPA meter and customer equipment extends outside the meter building or extends through an area that puts the meter at risk for damage, then analog and pulse output isolation devices shall be installed.

6.7.5 *Meter Data Collection*

Primary access to the MDC data is through the customer portal. Upon request, and depending on the meter communication method (see Section 6.4), BPA may allow a customer to have a direct MDC connection to a BPA meter. Customer Service Engineering can establish the RMS access agreement necessary for a customer to get read-only direct access to a BPA meter.

6.8 Polarity Convention

The following defines BPA's metering polarity conventions for revenue, interchange, and generation metering.

6.8.1 *Revenue Metering*

The power flow diagram defines power flow polarity and direction for a revenue meter. Revenue metering systems will be designed to provide accurate power measurement in all four quadrants.

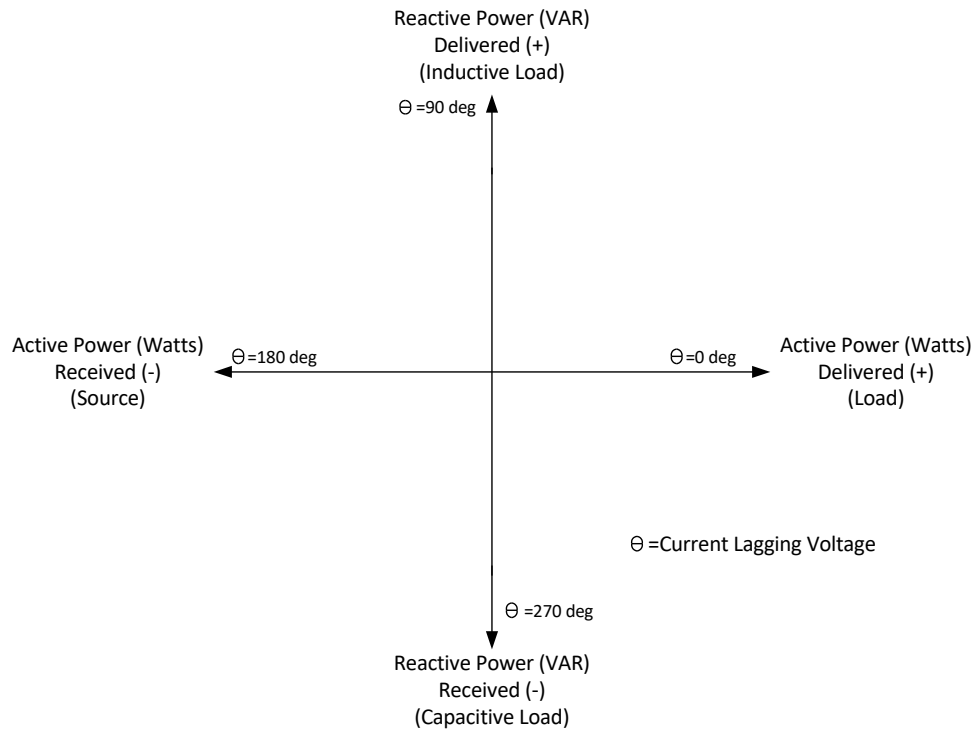


Figure 5.--- Revenue Metering Power Flow Diagram

Revenue metering CTs are connected such that current flow out of the BPA system is current into the meter. Power flow out of BPA's system is considered "OUT" to the MDC system.

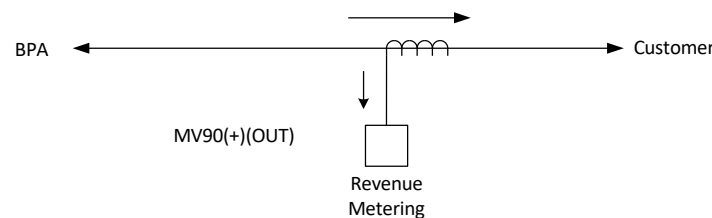


Figure 6.--- Revenue Metering Polarity Convention

6.8.2 Interchange Metering

Interchange metering CTs are connected such that power flow OUT of BPA results in current into the meter. This results in positive polarity data to kWh and kW (AGC) system, and power flow "OUT" to the MDC system.

If the interchange metering is provided by the adjacent balancing authority, kW and kWh quantities must be furnished to BPA using this data polarity convention. What is OUT to an Adjacent Balancing Authority is IN to BPA.

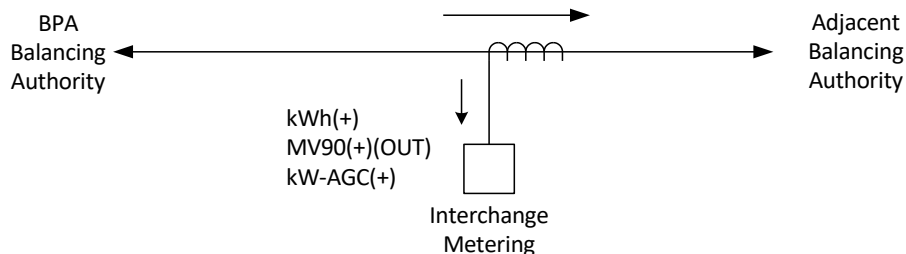


Figure 7.--- Interchange Metering Polarity Convention

6.8.3 Generation Metering

For generation metering that is only providing MDC/billing data, use the same polarity rules outlined for revenue metering. For generation metering providing both AGC data and MDC/billing data, the figure below illustrates the preferred metering CT connection. For proper data polarity, the MDC data will need to be reversed. When the meter is located in BPA's Balancing Authority, flow from the generator into BPA's system is considered "IN" from BPA's perspective.

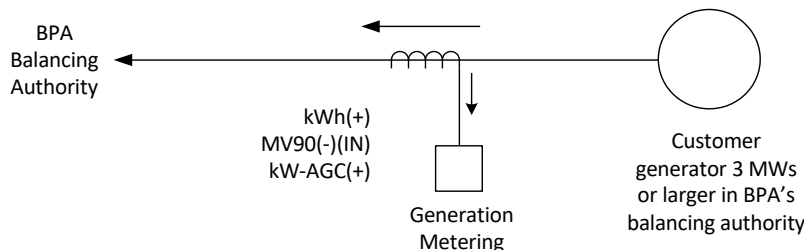


Figure 8.--- Generation Metering Polarity Convention

6.8.4 Meter Data Collection, kW, and kWh Data Reversal

When required, billing kWh, AGC kW, and control center hourly kWh data polarity can be reversed by modifying the SEL-735 configuration. Polarity for customer data can be reversed in the customer access SEL-2411 configuration.

6.9 Instrument Transformers

Instrument transformers include both current transformers (CTs) and voltage transformers (VTs).

6.9.1 Ownership and Maintenance

In BPA substations, BPA will own and maintain all instrument transformers.

In customer-owned substations, the customer typically owns and maintains their instrument transformers.

When the customer owns the instrument transformers, BPA will require the instrument transformers meet or exceed the requirements specified in this document.

Customer shall perform a minimum of on-site acceptance testing of the instrument transformers, as specified in this document. The customer may ask that BPA perform this testing on a reimbursable agreement.

6.9.2 *Secondary Connections and Outdoor Cables*

All CT circuit inter-rack wiring must be 12 AWG or larger.

Individual conductors shall be easily identifiable by color code or equivalent.

Copper-shielded cable shall be rated at 600 volts or higher. The cable shield shall be grounded per the owning utility's grounding practice.

In BPA substations, the CT outdoor cable design will follow standard STD-DC-0018 and the CT cable shall be 9 AWG or equivalent (0.8Ω per 1000 feet).

In non-BPA substations, the CT cable shall be 10 AWG (0.99Ω per 1000 feet), or better.

The CT secondary circuit DC resistance must never exceed 80% of the nameplate CT burden rating. The CT secondary circuit burden (DC resistance) equals the single-phase, one-way wire resistance plus the connected equipment resistance.

Where possible, control cables shall be routed perpendicular to high-voltage buses. When control cables must be run parallel to high-voltage or high-current buses, maintain maximum practical separation between the cables and the buses. Physical separation between a transient source and control cables is an effective means of transient control. Because mutual capacitance and mutual inductance are greatly influenced by circuit spacing, small increases in distance may produce substantial decreases in interaction between circuits.

Cables must be limited to the minimum length necessary to complete the circuit to the meter.

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

Voltage transformer secondary branch circuits shall be protected by a separate ACB or fuse. The secondary branch protection is generally located in the rack. BPA uses a 2.5 amp three-phase ACB for each secondary branch circuit.

The secondary neutral in the CT and VT cables is grounded at only one point per the owning utility's practice. BPA grounds their neutral wire at the first termination point where the cable enters the meter house.

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

Upon request to BPA Customer Service Engineering, BPA will consider allowing customer metering equipment on the same CT and VT circuits as the BPA meters. The following conditions apply to such considerations:

- The official meter of record is the BPA meter.
- VT secondary circuits shall be paralleled from rack to rack, with the BPA meter(s) on the first rack to touch the incoming secondary circuits after entering the building,

excluding a termination frame if one exists. Each rack shall have its own ACB or fuse protection. See Figure 11, CT & VT Secondary Indoor Connections.

- The BPA meter should be first device in the string of devices attached to the CT secondary circuit. This placement ensures BPA metering will not be inadvertently omitted from the current circuit because of testing or circuit revision.
- Terminal blocks on BPA's meter rack shall be the official demarcation point for CT and VT circuits. A customer who requires access to VT and CT circuits shall wire from the BPA terminal blocks. CT and VT circuits shall be wired in accordance with Figure 9 CT & VT Secondary Outdoor Connections, Figure 10 VT Meter and Relay Outdoor Connections, and Figure 11 CT and VT Secondary Indoor Connections.
- The customer meter or equipment shall not be located on the BPA metering rack. Approval to deviate from the standard application may be granted by Customer Service Engineering and documented in a customer contract 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.
- 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.
- The customer is responsible for installation and maintenance of its metering equipment. Customer metering equipment shall be installed such that the operation and maintenance of this metering system does not affect the operation of the BPA meter(s).
- Customer metering equipment shall include test switches for equipment isolation. See section 6.9.4, Test Switches.
- Multi-conductor CT and VT secondary cable shall be used for rack-to-rack wiring.
- A written agreement shall be executed between BPA and the customer prior to extending metering circuits from the BPA metering system to the customer metering equipment. The purpose of this agreement is to ensure that extension of the CT and VT circuits is executed in agreement with BPA's engineering practices and does not jeopardize the BPA metering system in any way. This agreement shall address all the conditions stated above.

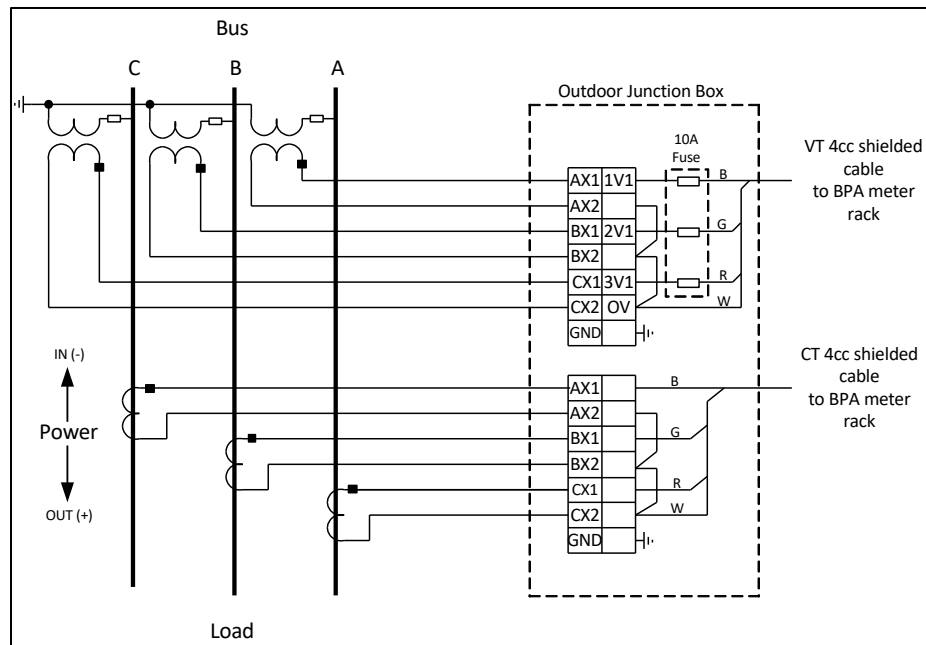


Figure 9.--- CT and VT Secondary Outdoor Connections

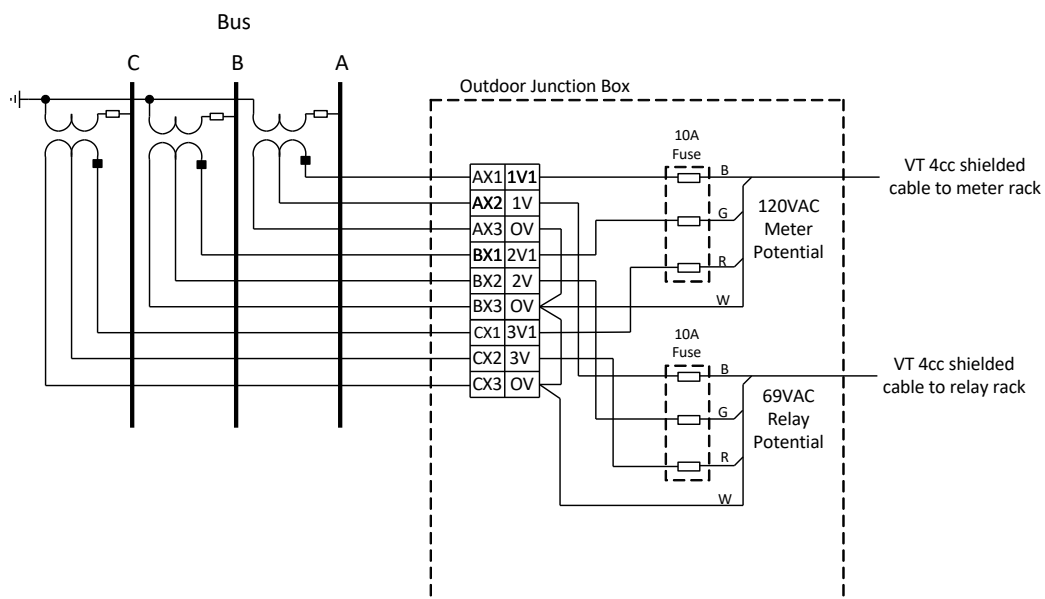


Figure 10.--- VT Meter and Relay Secondary Outdoor Connections

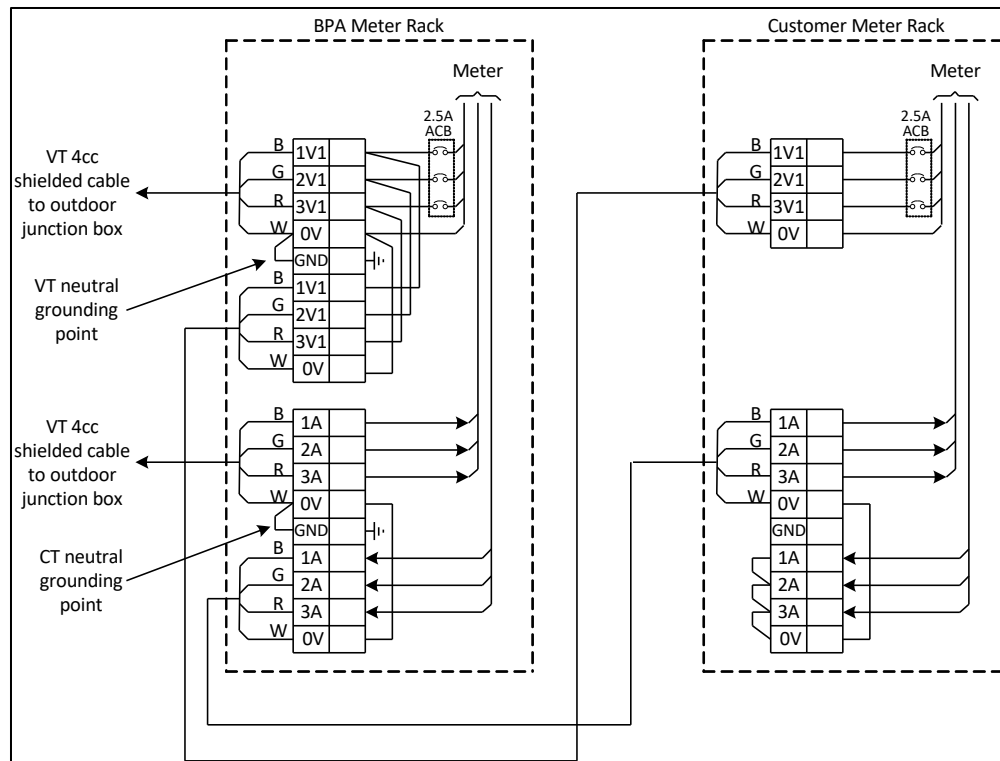


Figure 11.--- CT and VT Secondary Indoor Connections

6.9.3 Terminal Blocks

Terminal blocks are required on each metering rack, near the metering equipment, to provide a contact or interface point for all external wire connections. External wire connections include equipment power, voltage transformer and current transformer secondary wiring, energy pulse contact outputs, analog 0-1 mA outputs, equipment alarms, and grounding.

BPA prefers using ring lug type terminal blocks for CT circuits. For safety reasons the use of compression only terminal blocks should be avoided.

The potential and current circuits shall be wired on the terminal blocks 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.

The CT terminal blocks shall include provisions for safely shorting all terminals together.

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

6.9.4 Test Switches

Each metering device shall be wired to its own test switch located near the meter. This test switch assembly shall provide three functions: meter isolation from in-service VT and CT circuits, connection points for calibration, and connection points for in-service measurement. See Figure 12 below.

- **Voltage Elements:** Four single-pole switches for isolating the metering device from three-phase voltage and neutral.
- **Current Elements:** Three current double-pole switches shall first short-circuit and then isolate each phase current from the metering device. Each current switch shall contain an integral current test jack for measuring in-service current and isolation for meter testing.

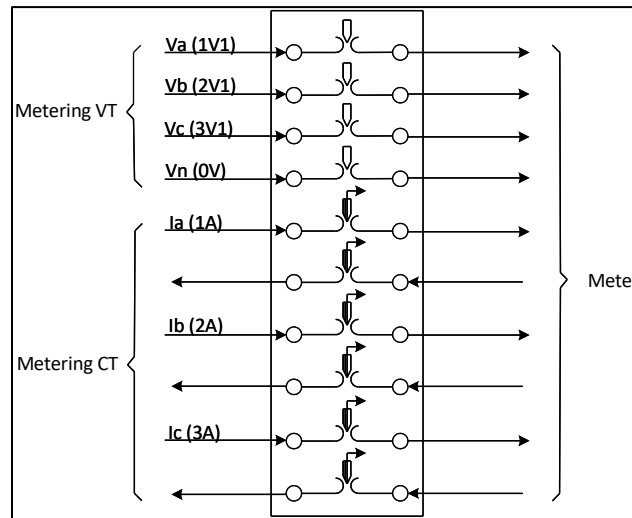


Figure 12--- Typical Test Switch

6.9.5 Conduit

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 and a four-conductor cable, the conduit diameter size must be a minimum of 2½ inches.

Above Ground: Use metal conduits or liquid-tight metallic flexible conduit to provide shielding for all above-ground installations. Conduit must be sized adequately for the cable fill and properly grounded.

6.9.6 Outdoor Junction Box

An outdoor junction box is required between the instrument transformers and meter house to allow for CT secondary circuit shorting and VT secondary circuit isolation without having to take a CT or VT primary outage at the station.

The outdoor junction box must be adequately sized for CT shorting blocks, VT secondary protection, and a minimum 6-inch gutter space for cable terminations.

The outdoor junction box shall be properly grounded.

Grounded metal conduit shall be used between the instrument transformer and outdoor junction box.

6.9.7 *Current Transformer Requirements*

Current transformers shall be the magnetic type. Other CT types, such as optical CTs, are not presently authorized by BPA.

All metering accuracy current transformers must meet or exceed IEEE standard C57.13 and all applicable ANSI C12 series standards that are in effect at the time of design. The CTs must be 0.3% accuracy class or better, 1.8 ohm burden, up to 3.0 load rating factor.

CT load rating factor must not exceed 3.0 to limit the secondary current to 15 amps. This will limit the stress on the secondary equipment, connections, and wiring.

BPA prefers to use high accuracy and extended-range metering current transformers in 230 and 525 kV applications, and under conditions in which the load is over a wide range. Refer to IEEE Standard C57.13.6 (2005) for high accuracy instrument transformers. These CTs shall be 0.15% accuracy class, 1.8 ohm burden, up to 3.0 load rating factor, and an extended accuracy range.

CT secondary windings must not be connected in parallel, such as combining CTs for two lines into one metering point. Metering CTs must be located in the line to measure line currents. The CTs must not be connected to the meter in a differential mode, in which the meter secondary current is the difference or sum between two or more CTs in the substation, as is common in a ring or breaker and a half bus configuration.

The meter current source shall be three metering accuracy CTs, located in the line, and one per phase. The CTs shall be positioned so they measure line current for all operational conditions. For main-and-transfer-bus arrangements, line CTs enable proper measurement for both the normal service condition using the line breaker and the alternative service condition when the line breaker is bypassed.

The CTs shall include certificates of tests that specify the ratio and phase angle corrections for the accuracy range with the standard IEEE burden of B1.8 ohms.

Dual- or multi-ratio CTs may be used only if the meter is connected to the full secondary ratio unless the tapped-down (intermediate) ratio(s) also provide full-rated accuracy.

Metering accuracy CTs must be used exclusively for revenue and AGC metering systems. In cases where instrument CTs are not available, the metering CT may be used for indicating ammeters or other low-burden devices. Executed customer agreements must be in place before additional equipment may be added to the CT circuits.

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

6.9.8 *Current Transformer Technical Application*

Customers who elect to supply CTs for BPA metering in customer-owned facilities must use BPA's selection philosophy. They need to demonstrate the CT selection made shall meet the 0.3% accuracy at burden B1.8 Ω over the expected load range of the customer facility being metered. This requirement applies to all voltage classes.

The following shall be specified when purchasing CTs:

- Accuracy Class: BPA requires 0.3% accuracy or better
- Burden: BPA requires B1.8 Ω
- Nominal System Voltage Rating: the nominal phase-to-phase voltage
- Physical Feature: Dry, oil-filled, gas insulated
- Rating Factor (3.0 or less): 1.0, 1.5, 2.0 or 3.0; do not exceed 3.0
- Ratio: XXXX:5

6.9.9 *Current Transformer Ratio Selection*

The following shall be followed when selecting a CT ratio for a typical metering application.

Maximum Load Current:

- The maximum load current should be based on equipment ratings. In some cases, the maximum load current may need to be determined from the customer historical energy demand data and estimating future load growth.
- The maximum current for a transmission line is assumed to be 120% of the emergency or -30 degree C current rating.
- The maximum current for a transformer is assumed to be 130% of the maximum MVA rating.
- The maximum current for a generator is assumed to be 100% of the MVA rating.

Minimum Load Current:

- The minimum load current should be based on equipment ratings.
- The minimum load current for a transmission line or transformer is assumed to be 10% of the maximum load current.
- For generation metering assume the minimum current is 5% of the maximum rated MVA.
- In some cases, the minimum load current may need to be determined from the customer historical energy demand data. In these cases, the minimum load is assumed to be 30% of the peak demand.
- Minimum current requirements for large generation meter applications need to be carefully analyzed where the metering system is required to measure both the generation energy output and back-feed station service load when the generation is down. BPA will select a CTR that satisfies the maximum generation output with as much low current accuracy as possible. It is assumed the minimum station service load is 10% of the maximum station service equipment rating. If greater plant station service load accuracy is necessary, additional station service metering or the use of high accuracy, extended range CTs may be required.

CT Ratio Selection:

- The current transformer ratio (CTR) selection ensures metering accuracy over the expected metered load range. The load range is considered to be between the maximum and minimum load current determined above. The CT ratio, rating factor, and accuracy class determines the overall CT accuracy operating range. A high accuracy CT may also be required to extend the accuracy operating range. BPA typically uses 0.15% accuracy class and extended range CTs on all 230kV and above applications and 0.3% accuracy CTs on all 115 kV and below applications.
- For the best CT performance and accuracy, the CT ratio and rating factor should be selected to meet the following:
 - The minimum load current should not be less than the CT minimum accuracy range. For a 0.3% accuracy class CT, the accuracy range is assumed to be 10-100% of the full load rating (e.g. for a 1000:5 CT, the full load rating would be 1000A). For a 0.15% accuracy class CT the accuracy range is assumed 5-100% of the full load rating, unless otherwise noted on the nameplate.
 - Verify the meter will operate accurately throughout the load range. The SEL-735 meter requires 0.01 amps minimum to function accurately.
 - The maximum load current should be between 80-95% of the CT primary current rating multiplied by the CT rating factor. The CT secondary current must not exceed 15 amps, and thus the CT rating factor must not exceed 3.0.
- High accuracy and extended range CTs should be considered for loads routinely less than 10% of the CT current rating.

6.9.10 BPA Standard Current Transformers

The following table shows the 69 kV through 230 kV typical BPA meter accuracy of current transformers and specifications. These CTs types will cover a majority of applications.

Table 2.— Standard BPA Meter Accuracy Current Transformers

Voltage	Ratio	Specifications	BPA Catalog No.
69 kV	1000:5	0.15% accuracy; extended range, 2.0 rating factor; 1.8 ohms burden; accuracy range 0.5-2000 amps primary	1022677
69 kV	100/200:5	0.3% accuracy; 2.0 rating factor; 1.8 ohms burden; accuracy range 10-200/20-400 amps primary	1022681
115 kV	1000:5	0.15% accuracy; extended range, 2.0 rating factor; 1.8 ohms burden; accuracy range 0.5-2000 amps primary	1022682
230 kV	2000:5	0.15% accuracy; 2.0 rating factor; 1.8 ohms burden; accuracy range 1-4000 amps primary	1021816
230 kV	1000:5	0.15% accuracy; 2.0 rating factor; 1.8 ohms burden; accuracy range 10-2000 amps primary	1023038
500kV	1000:5	6 cores, one metering core; 0.15% accuracy; 3.0 rating factor; 1.8 ohms burden; accuracy range 10-3000 amps primary	1022877
500kV	2000:5	6 cores, one metering core; 0.15% accuracy; 2.25 rating factor; 1.8 ohms burden; accuracy range 20-4500 amps primary	1022878
500kV	3000:5	6 cores, one metering core; 0.3% accuracy; 1.0 rating factor; 1.8 ohms burden; accuracy range 300-3000 amps primary	222898

6.9.11 CT Selection Examples

Below are four metering installation examples for determining the best current transformer.

6.9.11.1 Example 1: Revenue Metering

Situation:

Metering Primary Voltage: 12.5 kV

Maximum equipment rating (bank rating): 25 MVA (1155 A)

Maximum Load Current: 130% of bank rating = $(1.3)(1155 \text{ A}) = 1502 \text{ A}$

Minimum Load Current: 10% of maximum load current = $(0.1)(1502) = 150 \text{ A}$

Solution:

Based on the maximum transformer load of 1502 A, an 800/5, rating factor = 2.0 gives the best performance for this application. This CT will provide accuracy between 80 – 1600 A. The minimum load of 150 A is greater than 10% (80 A) of the CT rating. The 800:5 ratio and rating factor of 2.0 will serve for future load growth up to the transformer rating.

It is always important to check the CT nameplate ratings and manufacturer's test data to verify the CT performance range.

6.9.11.2 Example 2: Interchange Metering

Situation:

Metering Primary 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 Load Limit (line rating): 150 MVA (753 A) -30 degree C line rating

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:

Will the load ever reach the transmission line current rating during a contingency due to an outage of another facility? (Wide swing of load range must be accommodated.)

Will the load regularly alternate between plus and minus and often hover around the zero point? (Light load performance is an issue.)

Will the load be strong in one direction and then switch (seasonally or on/off or due to generation schedules) to be strong in the other direction, with little time at zero? (Light load performance may not be an issue.)

Solution:

The CT should cover the -30 degree C line rating of 753 A, maximum current = $753(1.2) = 904$ A.

A standard BPA 115 kV, 1000:5, rating factor 1.0 CT provides 0.3% or better accuracy from 100 A to 1000 A.

For better low-end performance an 800:5, rating factor 1.5 will provide 0.3% or better accuracy from 80 A to 1200 A. Alternatively, a 500:5, rating factor 2.0 will provide 0.3% or better accuracy from 50 A to 1000 A.

If light load accuracy is necessary a high accuracy 1000:5, rating factor 1.0 provides 0.15% accuracy nameplate rating 1 A to 1000 A.

It is always important to check the CT nameplate ratings and manufacturer's test data to verify the CT performance range.

6.9.11.3 Example 3, Large Load Interchange Metering

Situation:

Interchange between BPA and another balancing area.

Metering Primary 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, -30 degree C line rating

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:

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?)

Will the load regularly go bi-directional and often hover around the zero point? (Light load performance is an issue.)

Will the load be strong in one direction and then switch (seasonal or on/off or due to generation schedules) to be strong in the other direction, with little time at zero? (Light load performance may not be an issue.)

How important are near zero readings?

Solution:

The CT should cover the -30 degree C line rating of 3000 A, maximum current = $3000(1.2) = 3600$ A.

A standard BPA 230 kV, 3000:5, rating factor 1.5 CT provides 0.3% or better accuracy from 300 A to 4500 A.

For better low-end performance a 2000:5, rating factor 2.0 will provide 0.3% or better accuracy from 200 A to 4000 A.

If light load accuracy is necessary a high accuracy 2000:5, rating factor 2.0 provides 0.15% accuracy from 1 A to 4000 A.

It is always important to check the CT nameplate ratings and manufacturer's test data to verify the CT performance range.

6.9.11.4 Example 4: Generation Metering

Situation:

Metering must be accurate at both the high and low end.

Metering Primary 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)

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) backfeeds the generation site to supply the parasitic loads. This sets up a very wide swing between the maximum generation and the backfeed 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 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 1.25 A OUT (backfeed) for zero generation. This places an extreme range requirement on the CT specification.

Solution:

Based on a load swing of 1.25 A to 251 A primary, this application requires extended range and high accuracy CTs. Selecting a CT with a ratio of 200:5, rating factor 1.5, and high accuracy and extended range will provide 0.15% accuracy from 1.00 A to 300 A primary.

Always check the CT nameplate ratings and manufacturer's test data to verify the CT performance range.

6.9.12 *Current Transformer Testing Requirements*

Commission testing a new current transformer must include a ratio, polarity, secondary circuit burden, and insulation test. Freestanding CTs of 115 kV and above must also be power-factor tested.

6.9.13 *Voltage Transformer Requirements*

All voltage transformers (VTs) shall conform to the IEEE 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.

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 degree C with a 55 degree C rise while maintaining rated accuracy.

The VTs shall be positioned so they measure the voltage at the meter point for all possible switching configurations.

During the loss of AC station service power and when SEL-735 metering systems are 120VAC powered, the SEL-735 metering system will automatically switch its power source to the VT adding the following burden:

- For a redundant metering system, the VT burden is 190 VA.
- For a redundant metering system with no AGC back-up meter (small generation template) the VT burden is 110VA.
- For a single metering system, the VT burden is 60 VA.
- For cabinet meters with a convenience outlet, no additional burden needs to be added for the convenience outlet when calculating total VT burden. The field will need to check available capacity prior to using the convenience outlet.

Voltage transformers specified for revenue metering will follow the standard burden table below.

Table 3.— Standard Burden for Voltage Transformers

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

Selected VT ratios shall be consistent with the phase-to-ground voltage to be monitored. For typical wye-grounded power systems, VT primaries are connected phase-to-ground. Transformer secondary meter potentials are nominally 120 volts phase-to-ground. Acceptable secondary voltage is 67 – 300 volts line to ground. For 480 (277 line to ground) volt potential circuits, a 2.5:1 revenue-accuracy step down voltage transformer will be installed to lower the meter potential to a safer working level.

Customer-supplied VTs connected phase to phase for 2-element metering shall be considered on a case-by-case basis. The customer request for 2-element metering and BPA approval must be documented in writing.

The application of capacitor voltage transformers (CVT) and magnetic voltage transformers will follow STD-DS-000041 Instrument Transformers Design Standard.

MVTs maintain accuracy over time and are therefore preferred unless safety issues prohibit their use. MVTs are required when the metering is also being used to provide power quality data.

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

6.9.14 *Voltage Transformer Technical Application*

The following are to be specified when purchasing VTs:

- Accuracy Class: BPA requires 0.3% accuracy over name plate burden range
- Burden: W, X, Y, Z , and ZZ
- Nominal System Voltage Rating: the nominal phase-to-phase voltage
- Type: magnetic voltage transformer or capacitor voltage transformer
- Ratio: XXXX:1

Typical voltage transformer ratios for metering are listed in the following table.

Table 4.— Typical Voltage Transformer Ratios

0-0 Voltage	Voltage 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	577:1
230 kV	1150:1
525 kV	2500:1

6.9.15 *Voltage Transformer Testing Requirements*

Commission-testing a new VT must include a ratio, polarity, secondary circuit burden, and insulation test. Power factor test will be included on VTs 115 kV class and above.

6.10 Testing and Calibration

BPA will perform calibration tests at least every two years on all revenue, generation, and interchange meters.

Witness testing by BPA or customer will occur for meter commissioning, calibration, or replacement. When testing is to be witnessed, the testing party shall contact the other party a minimum of 2 weeks in advance of the test date. The witness party shall receive a copy of the test data from the testing party upon request.

The AGC kW signal provided from a common, agreed-upon source meter to both balancing authorities must be verified every two years during the meter test.

BPA test instruments used for meter calibration shall be calibrated yearly and traceable to the National Institute of Standards and Technology (NIST) Standards.

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

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

In-service potential and current checks must be performed at the time of initial meter energization and at the completion of each meter calibration. In-service checks are measurements of amplitude and phase angle of actual current and voltage quantities. Current in-service checks must be done with and without current test burden.

During in-service tests, live hourly kWh and AGC quantities are being transmitted to the Control Center. These tests require sufficient load be available to perform valid measurements.

All implemented meter outputs must be tested for accuracy and performance.

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

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).

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

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

7. REFERENCES

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.

American National Standards Institute (ANSI). ANSI C12.20, "Electricity Meters 0.1, 0.2, and 0.5 Accuracy Classes". Washington, D.C.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. "Requirements for Leased Multi-Tone Circuit – Voice Grade" (Technical Specification No. 10A-1, source: BPA Telecommunications Design Group TECT). Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. STD-DS-000003, "Outdoor Conduit Systems". Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. STD-DS-000021, "Electromagnetic Interference (EMI) Mitigation Practices". Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. STD-DS-000041, "Instrument Transformer Design Standard". Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. SPC Maintenance Standard: STD-MC-R00003, "AGC – Interchange MW Metering Common Source Verification Test Standard". Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. SPC Maintenance Standard: STD-MC-R00010, "Revenue Metering Maintenance Standard". Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. STD-N-000001, "Technical Requirements for Interconnection to the BPA Transmission Grid". Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Department of Energy (DOE). STD-P-000002, "Standard Compliance and Exception Policy." Portland, Oregon.

Bonneville Power Administration (BPA), U.S. Dept. of Energy. "Substation Ground Data List". Portland, Oregon.

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

Institute of Electronics and Electrical Engineers (IEEE). IEEE Standard C57.13.6, "IEEE Standard for High-Accuracy Instrument Transformers". New York, New York: 2005.

Institute of Electronics and Electrical Engineers (IEEE). IEEE Standard C57.13, "Requirements for Instrument Transformers". Washington, D.C.

North American Electric Reliability Corporation (NERC). NERC Standard BAL-005-1– "Automatic Generation Control". Princeton, NJ.

Western Electrical Coordinating Council (WECC). "Electric Industry Data Exchange (EIDE) Communications Protocol Documents" 1.0.5, Proposed by WECC DEWG 11/22/2006.

7.1 Associated Design Templates Drawings

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

Outdoor Junction Box:

325808 Layout and Wiring

24" Rack Mounted Revenue Meter:

336087 Block Diagram

336088 Schematics

336089 Layout and Wiring

336090 Bill of Material

24” Rack Mounted Large Interchange & Large Generation Metering:

335702 Block Diagram

335703 Logic Diagram

335704 Schematics

335705 Layout and Wiring

335706 Bill of Material

24” Rack Mounted Small Interchange & Small Generation Metering:

337250 Block Diagram

337251 Schematics

337254 Layout and Wiring

337253 Bill of Material

Cabinet Revenue Meter:

336087 Block Diagram

337260 Schematics

337262 Layout and Wiring

337261 Bill of Material

19” Rack Mounted Fast Track Revenue Meter Panel:

336087 Block Diagram

343052 Schematics

343053 Layout and Wiring

343054 Bill of Material