Subpart 3174—Measurement of Oil

SOURCE: 81 FR 81504, Nov. 17, 2016, unless otherwise noted.

§ 3174.1 Definitions and acronyms.

(a) As used in this subpart, the term:

Barrel (bbl) means 42 standard United States gallons.

Base pressure means 14.696 pounds per square inch, absolute (psia).

Base temperature means 60 °F.

Certificate of calibration means a document stating the base prover volume and other physical data required for the calibration of flow meters.

Composite meter factor means a meter factor corrected from normal operating pressure to base pressure. The composite meter factor is determined by proving operations where the pressure is considered constant during the measurement period between provings.

Configuration log means the list of constant flow parameters, calculation methods, alarm set points, and other values that are programmed into the flow computer in a CMS.

Coriolis meter means a device which by means of the interaction between a flowing fluid and oscillation of tube(s) infers a mass flow rate. The meter also infers the density by measuring the natural frequency of the oscillating tubes. The Coriolis meter consists of sensors and a transmitter, which convert the output from the sensors to signals representing volume and density.

Coriolis measurement system (CMS) means a metering system using a Coriolis meter in conjunction with a tertiary device, pressure transducer, and temperature transducer in order to derive and report gross standard oil volume. A CMS system provides real-time, on-line measurement of oil.

Displacement prover means a prover consisting of a pipe or pipes with known capacities, a displacement device, and detector switches, which sense when the displacement device has reached the beginning and ending points of the calibrated section of pipe. Displacement provers can be portable or fixed.

Dynamic meter factor means a kinetic meter factor derived by linear interpolation or polynomial fit, used for conditions where a series of meter factors have been determined over a range of normal operating conditions.

Event log means an electronic record of all exceptions and changes to the flow parameters contained within the configuration log that occur and have an impact on a quantity transaction record.

Gross standard volume means a volume of oil corrected to base pressure and temperature.

Indicated volume means the uncorrected volume indicated by the meter in a lease automatic custody transfer system or the Coriolis meter in a CMS. For a positive displacement meter, the indicated volume is represented by the non-resettable totalizer on the meter head. For Coriolis meters, the indicated volume is the uncorrected (without the meter factor) mass of liquid divided by the density.

Innage gauging means the level of a liquid in a tank measured from the datum plate or tank bottom to the surface of the liquid.

Lease automatic custody transfer (LACT) system means a system of components designed to provide for the unattended custody transfer of oil produced from a lease(s), unit PA(s), or CA(s) to the transporting carrier while providing a proper and accurate means for determining the net standard volume and quality, and fail-safe and tamper-proof operations.

Master meter prover means a positive displacement meter or Coriolis meter that is selected, maintained, and operated to serve as the reference device for the proving of another meter. A comparison of the master meter to the Facility Measurement Point (FMP) line meter output is the basis of the master-meter method.

Meter factor means a ratio obtained by dividing the measured volume of liquid that passed through a prover or master meter during the proving by the measured volume of liquid that passed through the line meter during the proving, corrected to base pressure and temperature.

Net standard volume means the gross standard volume corrected for quantities of non-merchantable substances such as sediment and water.

Outage gauging means the distance from the surface of the liquid in a tank to the reference gauge point of the tank.

Positive displacement meter means a meter that registers the volume passing through the meter using a system which constantly and mechanically isolates the flowing liquid into segments of known volume.

Quantity transaction record (QTR) means a report generated by CMS equipment that summarizes the daily and hourly gross standard volume calculated by the flow computer and the average or totals of the dynamic data that is used in the calculation of gross standard volume.

Tertiary device means, for a CMS, the flow computer and associated memory, calculation, and display functions.

Transducer means an electronic device that converts a physical property, such as pressure, temperature, or electrical resistance, into an electrical output signal that varies proportionally with the magnitude of the physical property. Typical output signals are in the form of electrical potential (volts), current (milliamps), or digital pressure or temperature readings. The term transducer includes devices commonly referred to as transmitters.

Vapor tight means capable of holding pressure differential only slightly higher than that of installed pressure-relieving or vapor recovery devices.

(b) As used in this subpart, the following acronyms carry the meaning prescribed:

API means American Petroleum Institute.

CA has the meaning set forth in §3170.3 of this part.

COA has the meaning set forth in §3170.3 of this part.

CPL means correction for the effect of pressure on a liquid.

CTL means correction for the effect of temperature on a liquid.

NIST means National Institute of Standards and Technology.

PA has the meaning set forth in §3170.3 of this part.

PMT means Production Measurement Team.

PSIA means pounds per square inch, absolute.

S&W means sediment and water.

§ 3174.2 General requirements.

(a) Oil may be stored only in tanks that meet the requirements of §3174.5(b) of this subpart.

(b) Oil must be measured on the lease, unit PA, or CA, unless approval for off-lease measurement is obtained under §§3173.22 and 3173.23 of this part.

(c) Oil produced from a lease, unit PA, or CA may not be commingled with production from other leases, unit PAs, or CAs or non-Federal properties before the point of royalty measurement, unless prior approval is obtained under §§3173.14 and 3173.15 of this part.

(d) An operator must obtain a BLM-approved FMP number under §§3173.12 and 3173.13 of this part for each oil measurement facility where the measurement affects the calculation of the volume or quality of production on which royalty is owed (*i.e.*, oil tank used for tank gauging, LACT system, CMS, or other approved metering device), except as provided in paragraph (h) of this section.

(e) Except as provided in paragraph (h) of this section, all equipment used to measure the volume of oil for royalty purposes installed after January 17, 2017 must comply with the requirements of this subpart.

(f) Except as provided in paragraph (h) of this section, measuring procedures and equipment used to measure oil for royalty purposes, that is in use on January 17, 2017, must comply with the requirements of this subpart on or before the date the operator is required to apply for an FMP number under 3173.12(e) of this part. Prior to that date, measuring procedures and equipment used to measure oil for royalty purposes, that is in use on January 17, 2017 must continue to comply with the requirements of Onshore Oil and Gas Order No. 4, Measurement of oil, §3164.1(b) as contained in 43 CFR part 3160, (revised October 1, 2016), and any COAs and written orders applicable to that equipment.

(g) The requirement to follow the approved equipment lists identified in §§3174.6(b)(5)(ii)(A), 3174.6(b)(5)(iii), 3174.8(a)(1), and 3174.9(a) does not apply until January 17, 2019. The operator or manufacturer must obtain approval of a particular make, model, and size by submitting the test data used to develop performance specifications to the PMT to review.

(h) Meters used for allocation under a commingling and allocation approval under § 3173.14 are not required to meet the requirements of this subpart.

§ 3174.3 Incorporation by reference (IBR).

(a) Certain material specified in this section is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. Operators must comply with all incorporated standards and material, as they are listed in this section. To enforce any edition other than that specified in this section, the BLM must publish a rule in the FEDERAL REGISTER, and the material must be reasonably available to the public. All approved material is available for inspection at the Bureau of Land Management, Division of Fluid Minerals, 20 M Street SE., Washington, DC 20003, 202–912–7162; at all BLM offices with jurisdiction over oil and gas activities; and is available from the sources listed below. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030 or go to *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*.

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005; telephone 202–682–8000; API also offers free, read-only access to some of the material at *http://publications.api.org*.

(1) API Manual of Petroleum Measurement Standards (MPMS) Chapter 2—Tank Calibration, Section 2A, Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method; First Edition, February 1995; Reaffirmed February 2012 (''API 2.2A''), IBR approved for § 3174.5(c).

(2) API MPMS Chapter 2—Tank Calibration, Section 2.2B, Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method; First Edition, March 1989, Reaffirmed January 2013 (''API 2.2B''), IBR approved for § 3174.5(c).

(3) API MPMS Chapter 2—Tank Calibration, Section 2C, Calibration of Upright Cylindrical Tanks Using the Optical-triangulation Method; First Edition, January 2002; Reaffirmed May 2008 (''API 2.2C''), IBR approved for § 3174.5(c).

(4) API MPMS Chapter 3, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products; Third Edition, August 2013 (''API 3.1A''), IBR approved for §§ 3174.5(b), 3174.6(b).

(5) API MPMS Chapter 3—Tank Gauging, Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging; Second Edition, June 2001; Reaffirmed August 2011 (''API 3.1B''), IBR approved for § 3174.6(b).

(6) API MPMS Chapter 3—Tank Gauging, Section 6, Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems; First Edition, February 2001; Errata September 2005; Reaffirmed October 2011 (''API 3.6''), IBR approved for § 3174.6(b).

(7) API MPMS Chapter 4—Proving Systems, Section 1, Introduction; Third Edition, February 2005; Reaffirmed June 2014 (''API 4.1''), IBR approved for § 3174.11(c).

(8) API MPMS Chapter 4—Proving Systems, Section 2, Displacement Provers; Third Edition, September 2003; Reaffirmed March 2011, Addendum February 2015 (''API 4.2''), IBR approved for §§ 3174.11(b) and (c).

(9) API MPMS Chapter 4, Section 5, Master-Meter Provers; Fourth Edition, June 2016, (''API 4.5''), IBR approved for § 3174.11(b).

(10) API MPMS Chapter 4—Proving Systems, Section 6, Pulse Interpolation; Second Edition, May 1999; Errata April 2007; Reaffirmed October 2013 (''API 4.6''), IBR approved for § 3174.11(c).

(11) API MPMS Chapter 4, Section 8, Operation of Proving Systems; Second Edition, September 2013 (''API 4.8''), IBR approved for § 3174.11(b).

(12) API MPMS Chapter 4—Proving Systems, Section 9, Methods of Calibration for Displacement and Volumetric Tank Provers, Part 2, Determination of the Volume of Displacement and Tank Provers by the Waterdraw Method of Calibration; First Edition, December 2005; Reaffirmed July 2015 (''API 4.9.2''), IBR approved for §3174.11(b).

(13) API MPMS Chapter 5—Metering, Section 6, Measurement of Liquid Hydrocarbons by Coriolis Meters; First Edition, October 2002; Reaffirmed November 2013 (''API 5.6''), IBR approved for §§3174.9(e), 3174.11(h) and (i).

(14) API MPMS Chapter 6—Metering Assemblies, Section 1, Lease Automatic Custody Transfer (LACT) Systems; Second Edition, May 1991; Reaffirmed May 2012 (''API 6.1''), IBR approved for §3174.8(a) and (b).

(15) API MPMS Chapter 7, Temperature Determination; First Edition, June 2001, Reaffirmed February 2012 (''API 7''), IBR approved for §§3174.6(b), 3174.8(b).

(16) API MPMS Chapter 7.3, Temperature Determination—Fixed Automatic Tank Temperature Systems; Second Edition, October 2011 (''API 7.3''), IBR approved for §3174.6(b).

(17) API MPMS Chapter 8, Section 1, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; Fourth Edition, October 2013 (''API 8.1''), IBR approved for §§3174.6(b), 3174.11(h).

(18) API MPMS Chapter 8, Section 2, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products; Third Edition, October 2015 (''API 8.2''), IBR approved for §§3174.6(b), 3174.8(b), 3174.11(h).

(19) API MPMS Chapter 8—Sampling, Section 3, Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products; First Edition, October 1995; Errata March 1996; Reaffirmed, March 2010 (''API 8.3''), IBR approved for §§3174.8(b), 3174.11(h).

(20) API MPMS Chapter 9, Section 1, Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method; Third Edition, December 2012 (''API 9.1''), IBR approved for §§3174.6(b), 3174.8(b).

(21) API MPMS Chapter 9, Section 2, Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer; Third Edition, December 2012 (''API 9.2''), IBR approved for §§3174.6(b), 3174.8(b).

(22) API MPMS Chapter 9, Section 3, Standard Test Method for Density, Relative Density, and API Gravity of Crude Petroleum and Liquid Petroleum Products by Thermohydrometer Method; Third Edition, December 2012 (''API 9.3''), IBR approved for §§3174.6(b), 3174.8(b).

(23) API MPMS Chapter 10, Section 4, Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure); Fourth Edition, October 2013; Errata March 2015 (''API 10.4''), IBR approved for §§3174.6(b), 3174.8(b).

(24) API MPMS Chapter 11—Physical Properties Data, Section 1, Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products and Lubricating Oils; May 2004, Addendum 1 September 2007; Reaffirmed August 2012 (''API 11.1''), IBR approved for §§3174.9(f), 3174.12(a).

(25) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2, Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 1, Introduction; Second Edition, May 1995; Reaffirmed March 2014 (''API 12.2.1''), IBR approved for §§3174.8(b), 3174.9(g).

(26) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2, Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2, Measurement Tickets; Third Edition, June 2003; Reaffirmed September 2010 (''API 12.2.2''), IBR approved for §§3174.8(b), 3174.9(g).

(27) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2, Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 3, Proving Report; First Edition, October 1998; Reaffirmed March 2009 (''API 12.2.3''), IBR approved for §3174.11(c) and (i).

(28) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2, Calculation of Petroleum Quantities

Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 4, Calculation of Base Prover Volumes by the Waterdraw Method; First Edition, December 1997; Reaffirmed March 2009; Errata July 2009 (''API 12.2.4''), IBR approved for § 3174.11(b).

(29) API MPMS Chapter 13—Statistical Aspects of Measuring and Sampling, Section 1, Statistical Concepts and Procedures in Measurements; First Edition, June 1985 Reaffirmed February 2011; Errata July 2013 (''API 13.1''), IBR approved for § 3174.4(a).

(30) API MPMS Chapter 13, Section 3, Measurement Uncertainty; First Edition, May, 2016 (''API 13.3''), IBR approved for § 3174.4(a).

(31) API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 1, General Equations and Uncertainty Guidelines; Fourth Edition, September 2012; Errata July 2013 (''API 14.3.1''), IBR approved for § 3174.4(a).

(32) API MPMS Chapter 18—Custody Transfer, Section 1, Measurement Procedures for Crude Oil Gathered From Small Tanks by Truck; Second Edition, April 1997; Reaffirmed February 2012 (''API 18.1''), IBR approved for § 3174.6(b).

(33) API MPMS Chapter 18, Section 2, Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods, First Edition, July 2016 (''API 18.2''), IBR approved for § 3174.6(b).

(34) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 2, Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters; First Edition, June 1998; Reaffirmed August 2011 (''API 21.2''), IBR approved for §§ 3174.8(b), 3174.9(f), 3174.10(f).

(35) API Recommended Practice (RP) 12R1, Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service; Fifth Edition, August 1997; Reaffirmed April 2008 (''API RP 12R1''), IBR approved for § 3174.5(b).

(36) API RP 2556, Correction Gauge Tables For Incrustation; Second Edition, August 1993; Reaffirmed November 2013 (''API RP 2556''), IBR approved for § 3174.5(c).

NOTE 1 TO § 3174.3(B): You may also be able to purchase these standards from the following resellers: Techstreet, 3916 Ranchero Drive, Ann Arbor, MI 48108; telephone 734–780–8000; *www.techstreet.com/api/apigate.html*; IHS Inc., 321 Inverness Drive South, Englewood, CO 80112; 303–790–0600; *www.ihs.com*; SAI Global, 610 Winters Avenue, Paramus, NJ 07652; telephone 201–986–1131; *http://infostore.saiglobal.com/store/*.

§ 3174.4 Specific measurement performance requirements.

(a) *Volume measurement uncertainty levels*. (1) The FMP must achieve the following overall uncertainty levels as calculated in accordance with statistical concepts described in API 13.1, the methodologies in API 13.3, and the quadrature sum (square root of the sum of the squares) method described in API 14.3.1, Subsection 12.3 (all incorporated by reference, see § 3174.3) or other methods approved under paragraph (d):

TABLE 1 TO § 3174.4—VOLUME MEASUREMENT UNCERTAINTY LEVELS

If the averaging period volume (see definition 43 CFR 3170.3) is:	The overall volume measurement uncertainty must be within:
1. Greater than or equal to 30,000 bbl/month.	±0.50 percent.
2. Less than 30,000 bbl/month	±1.50 percent.

(2) Only a BLM State Director may grant an exception to the uncertainty levels prescribed in paragraph (a)(1) of this section, and only upon:

(i) A showing that meeting the required uncertainly level would involve extraordinary cost or unacceptable adverse environmental effects; and

(ii) Written concurrence of the PMT, prepared in coordination with the Deputy Director.

(b) *Bias*. The measuring equipment used for volume determinations must achieve measurement without statistically significant bias.

(c) *Verifiability*. All FMP equipment must be susceptible to independent verification by the BLM of the accuracy and validity of all inputs, factors, and equations that are used to determine quantity or quality. Verifiability includes the ability to independently recalculate volume and quality based on source records.

(d) *Alternative equipment*. The PMT will make a determination under § 3174.13 of this subpart regarding whether proposed alternative equipment or measurement procedures meet or exceed the objectives and intent of this section.

§ 3174.5 Oil measurement by tank gauging—general requirements.

(a) *Measurement objective*. Oil measurement by tank gauging must accurately compute the total net standard volume of oil withdrawn from a properly calibrated sales tank by following the activities prescribed in § 3174.6 and the requirements of § 3174.4 of this subpart to determine the quantity and quality of oil being removed.

(b) *Oil tank equipment*. (1) Each tank used for oil storage must comply with the recommended practices listed in API RP 12R1 (incorporated by reference, see § 3174.3).

(2) Each oil storage tank must be connected, maintained, and operated in compliance with §§ 3173.2, 3173.6, and 3173.7 of this part.

(3) All oil storage tanks, hatches, connections, and other access points must be vapor tight. Unless connected to a vapor recovery or flare system, all tanks must have a pressure-vacuum relief valve installed at the highest point in the vent line or connection with another tank. All hatches, connections, and other access points must be installed and maintained in accordance with manufacturers' specifications.

(4) All oil storage tanks must be clearly identified and have an operator-generated number unique to the lease, unit PA, or CA, stenciled on the tank and maintained in a legible condition.

(5) Each oil storage tank associated with an approved FMP that has a tank-gauging system must be set and maintained level.

(6) Each oil storage tank associated with an approved FMP that has a tank-gauging system must be equipped with a distinct gauging reference point, consistent with API 3.1A (incorporated by reference, see § 3174.3). The height of the reference point must be stamped on a fixed bench-mark plate or stenciled on the tank near the gauging hatch, and be maintained in a legible condition.

(c) *Sales tank calibrations*. The operator must accurately calibrate each oil storage tank associated with an approved FMP that has a tank-gauging system using either API 2.2A, API 2.2B, or API 2.2C; and API RP 2556 (all incorporated by reference, see § 3174.3). The operator must:

(1) Determine sales tank capacities by tank calibration using actual tank measurements;

(i) The unit volume must be in barrels (bbl); and

(ii) The incremental height measurement must match gauging increments specified in § 3174.6(b)(5)(i)(C);

(2) Recalibrate a sales tank if it is relocated or repaired, or the capacity is changed as a result of denting, damage, installation, removal of interior components, or other alterations; and

(3) Submit sales tank calibration charts (tank tables) to the AO within 45 days after calibration. Tank tables may be in paper or electronic format.

§ 3174.6 Oil measurement by tank gauging—procedures.

(a) The procedures for oil measurement by tank gauging must comply with the requirements outlined in this section.

(b) The operator must follow the procedures identified in API 18.1 or API 18.2 (both incorporated by reference, see § 3174.3) as further specified in this paragraph to determine the quality and quantity of oil measured under field conditions at an FMP.

(1) *Isolate tank*. Isolate the tank for at least 30 minutes to allow contents to settle before proceeding with tank gauging operations. The tank isolating valves must be closed and sealed under § 3173.2 of this part.

(2) *Determine opening oil temperature*. Determination of the temperature of oil contained in a sales tank must comply with paragraphs (b)(2)(i) through (iii) of this section, API 7, and API 7.3 (both incorporated by reference, see § 3174.3). Opening temperature may be determined before, during, or after sampling.

(i) Glass thermometers must be clean, be free of fluid separation, have a minimum graduation of 1.0 °F, and have an accuracy of ±0.5 °F.

(ii) Electronic thermometers must have a minimum graduation of 0.1 °F and have an accuracy of ±0.5 °F.

(iii) Record the temperature to the nearest 1.0 °F for glass thermometers or 0.1 °F for portable electronic thermometers.

(3) *Take oil samples.* Sampling operations must be conducted prior to taking the opening gauge unless automatic sampling methods are being used. Sampling of oil removed from an FMP tank must yield a representative sample of the oil and its physical properties and must comply with API 8.1 or API 8.2 (both incorporated by reference, see § 3174.3).

(4) *Determine observed oil gravity.* Tests for oil gravity must comply with paragraphs (b)(4)(i) through (iii) of this section and API 9.1, API 9.2, or API 9.3 (all incorporated by reference, see § 3174.3).

(i) The hydrometer or thermohydrometer (as applicable) must be calibrated for an oil gravity range that includes the observed gravity of the oil sample being tested and must be clean, with a clearly legible oil gravity scale and with no loose shot weights.

(ii) Allow the temperature to stabilize for at least 5 minutes prior to reading the thermometer.

(iii) Read and record the observed API oil gravity to the nearest 0.1 degree. Read and record the temperature reading to the nearest 1.0 °F.

(5) *Measure the opening tank fluid level.* Take and record the opening gauge only after samples have been taken, unless automatic sampling methods are being used. Gauging must comply with either paragraph (b)(5)(i) of this section, API 3.1A, and API 18.1 (both incorporated by reference, see § 3174.3); or paragraph (b)(5)(ii) of this section, API 3.1B, API 3.6, and API 18.2 (all incorporated by reference, see § 3174.3); or paragraph (b)(5)(iii) of this section for dynamic volume determination.

(i) For manual gauging, comply with the requirements of API 3.1A and API 18.1 (both incorporated by reference, see § 3174.3) and the following:

(A) The proper bob must be used for the particular measurement method, *i.e.*, either innage gauging or outage gauging;

(B) A gauging tape must be used. The gauging tape must be made of steel or corrosion-resistant material with graduation clearly legible, and must not be kinked or spliced;

(C) Either obtain two consecutive identical gauging measurements for any tank regardless of size, or:

(*1*) For tanks of 1,000 bbl or less in capacity, three consecutive measurements that are within 1/4-inch of each other and average these three measurements to the nearest ¼ inch; or

(*2*) For tanks greater than 1,000 bbl in capacity, three consecutive measurements within ⅛ inch of each other, averaging these three measurements to the nearest ⅛ inch.

(D) A suitable product-indicating paste may be used on the tape to facilitate the reading. The use of chalk or talcum powder is prohibited; and

(E) The same tape and bob must be used for both opening and closing gauges.

(ii) For automatic tank gauging (ATG), comply with the requirements of API 3.1B, API 3.6, and API 18.2 (all incorporated by reference, see § 3174.3) and the following:

(A) The specific makes and models of ATG that are identified and described at *www.blm.gov* are approved for use;

(B) The ATG must be inspected and its accuracy verified to within ±¼ inch in accordance with API 3.1B, Subsection 9 (incorporated by reference, see § 3174.3) at least once a month or prior to sales, whichever is latest, or any time at the request of the AO. If the ATG is found to be out of tolerance, the ATG must be calibrated prior to sales; and

(C) A log of field verifications must be maintained and available upon request. The log must include the following information: The date of verification; the as-found manual gauge readings; the as-found ATG readings; and whether the ATG was field calibrated. If the ATG was field calibrated, the as-left manual gauge readings and as-left ATG readings must be recorded.

(iii) For dynamic volume determination under API 18.2, Subsection 10.1.1, (incorporated by reference, see § 3174.3), the specific makes and models of inline meters that are identified and described at *www.blm.gov* are approved for use.

(6) *Determine S&W content.* Using the oil samples obtained pursuant to paragraph (b)(3) of this section, determine the S&W content of the oil in the sales tanks, according to API 10.4 (incorporated by reference, see § 3174.3).

(7) *Transfer oil.* Break the tank load line valve seal and transfer oil to the tanker truck. After transfer is complete, close the tank valve and seal the valve under §§ 3173.2 and 3173.5 of this part.

(8) *Determine closing oil temperature.* Determine the closing oil temperature using the procedures in paragraph (b)(2) of this section.

(9) *Take closing gauge.* Take the closing tank gauge using the procedures in paragraph (b)(5) of this section.

(10) *Complete measurement ticket.* Following procedures in § 3174.12.

§ 3174.7 LACT system—general requirements.

(a) A LACT system must meet the construction and operation requirements and minimum standards of this section, § 3174.8, and § 3174.4.

(b) A LACT system must be proven as prescribed in § 3174.11 of this subpart.

(c) Measurement tickets must be completed under § 3174.12(b) of this subpart.

(d) All components of a LACT system must be accessible for inspection by the AO.

(e)(1) The operator must notify the AO, within 72 hours after discovery, of any LACT system failures or equipment malfunctions that may have resulted in measurement error.

(2) Such system failures or equipment malfunctions include, but are not limited to, electrical, meter, and other failures that affect oil measurement.

(f) Any tests conducted on oil samples extracted from LACT system samplers for determination of temperature, oil gravity, and S&W content must meet the requirements and minimum standards in § 3174.6(b)(2), (4), and (6) of this subpart.

(g) Automatic temperature compensators and automatic temperature and gravity compensators are prohibited.

§ 3174.8 LACT system—components and operating requirements.

(a) *LACT system components.* Each LACT system must include all of the equipment listed in API 6.1 (incorporated by reference, see § 3174.3), with the following exceptions:

(1) The custody transfer meter must be a positive displacement meter or a Coriolis meter. The specific make, models, and sizes of positive displacement or Coriolis meter and associated software that are identified and described at *www.blm.gov* are approved for use.

(2) An electronic temperature averaging device must be installed.

(3) Meter back pressure must be applied by a back pressure valve or other controllable means of applying back pressure to ensure single-phase flow.

(b) *LACT system operating requirements.* Operation of all LACT system components must meet the requirements of API 6.1 (incorporated by reference, see § 3174.3) and the following:

(1) Sampling must be conducted according to API 8.2 and API 8.3 (both incorporated by reference, see § 3174.3) and the following:

(i) The sample extractor probe must be inserted within the center half of the flowing stream;

(ii) The extractor probe must be horizontally oriented; and

(iii) The external body of the extractor probe must be marked with the direction of the flow.

(2) Any tests conducted on oil samples extracted from LACT system samplers for determination of oil gravity and S&W content must meet the requirements of either API 9.1, API 9.2, or API 9.3, and API 10.4 (all incorporated by reference, see § 3174.3).

(3) The composite sample container must be emptied and cleaned upon completion of sample withdrawal.

(4) The positive displacement or Coriolis meter (see § 3174.10) must be equipped with a non-resettable totalizer. The meter must include or allow for the attachment of a device that

generates at least 8,400 pulses per barrel of registered volume.

(5) The system must have a pressure-indicating device downstream of the meter, but upstream of meter-proving connections. The pressure-indicating device must be capable of providing pressure data to calculate the CPL correction factor.

(6) An electronic temperature averaging device must be installed, operated, and maintained as follows:

(i) The temperature sensor must be placed in compliance with API 7 (incorporated by reference, see § 3174.3);

(ii) The electronic temperature averaging device must be volume-weighted and take a temperature reading following API 21.2, Subsection 9.2.8 (incorporated by reference, see § 3174.3);

(iii) The average temperature for the measurement ticket must be calculated by the volumetric averaging method using API 21.2, Subsection 9.2.13.2a (incorporated by reference, see § 3174.3);

(iv) The temperature averaging device must have a reference accuracy of ±0.5 °F or better, and have a minimum graduation of 0.1 °F; and

(v) The temperature averaging device must include a display of instantaneous temperature and the average temperature calculated since the measurement ticket was opened.

(vi) The average temperature calculated since the measurement ticket was opened must be used to calculate the CTL correction factor.

(7) Determination of net standard volume: Calculate the net standard volume at the close of each measurement ticket following the guidelines in API 12.2.1 and API 12.2.2 (both incorporated by reference, see § 3174.3).

§ 3174.9 Coriolis measurement systems (CMS)—general requirements and components.

The following Coriolis measurement systems section is intended for Coriolis measurement applications independent of LACT measurement systems.

(a) A CMS must meet the requirements and minimum standards of this section, § 3174.4, and § 3174.10.

(b) The specific makes, models, and sizes of Coriolis meters and associated software that have been reviewed by the PMT, as provided in § 3174.13, approved by the BLM, and identified and described at *www.blm.gov* are approved for use.

(c) A CMS system must be proven at the frequency and under the requirements of § 3174.11 of this subpart.

(d) Measurement tickets must be completed under § 3174.12(b) of this subpart.

(e) A CMS at an FMP must be installed with the components listed in API 5.6 (incorporated by reference, see § 3174.3). Additional requirements are as follows:

(1) The pressure transducer must meet the requirements of § 3174.8(b)(5) of this subpart.

(2) Temperature determination must meet the requirements of § 3174.8(b)(6) of this subpart.

(3) If nonzero S&W content is to be used in determining net oil volume, the sampling system must meet the requirements of § 3174.8(b)(1) through (3) of this subpart. If no sampling system is used, or the sampling system does not meet the requirements of § 3174.8(b)(1) through (3) of this subpart, the S&W content must be reported as zero;

(4) Sufficient back pressure must be applied to ensure single phase flow through the meter.

(f) *Determination of API oil gravity.* The API oil gravity reported for the measurement ticket period must be determined by one of the following methods:

(1) Determined from a composite sample taken pursuant to § 3174.8(b)(1) through (3) of this subpart; or

(2) Calculated from the average density as measured by the CMS over the measurement ticket period under API 21.2, Subsection 9.2.13.2a (incorporated by reference, see § 3174.3). Density must be corrected to base temperature and pressure using API 11.1 (incorporated by reference, see § 3174.3).

(g) *Determination of net standard volume.* Calculate the net standard volume at the close of each measurement ticket following the guidelines in API 12.2.1 and API 12.2.2 (both incorporated by reference, see § 3174.3).

§ 3174.10 Coriolis meter for LACT and CMS measurement applications—operating requirements.

(a) *Minimum electronic pulse level.* The Coriolis meter must register the volume of oil passing through the meter as determined by a system that constantly emits electronic pulse signals representing the indicated volume measured. The pulse per unit volume must be set at a minimum of 8,400 pulses per barrel.

(b) *Meter specifications.* (1) The Coriolis meter specifications must identify the make and model of the Coriolis meter to which they apply and must include the following:

(i) The reference accuracy for both mass flow rate and density, stated in either percent of reading, percent of full scale, or units of measure;

(ii) The effect of changes in temperature and pressure on both mass flow and fluid density readings, and the effect of flow rate on density readings. These specifications must be stated in percent of reading, percent of full scale, or units of measure over a stated amount of change in temperature, pressure, or flow rate (*e.g.*, ''±0.1 percent of reading per 20 psi'');

(iii) The stability of the zero reading for volumetric flow rate. The specifications must be stated in percent of reading, percent of full scale, or units of measure;

(iv) Design limits for flow rate and pressure; and

(v) Pressure drop through the meter as a function of flow rate and fluid viscosity.

(2) Submission of meter specifications: The operator must submit Coriolis meter specifications to the BLM upon request.

(c) *Non-resettable totalizer.* The Coriolis meter must have a non-resettable internal totalizer for indicated volume.

(d) *Verification of meter zero value using the manufacturer's specifications.* If the indicated flow rate is within the manufacturer's specifications for zero stability, no adjustments are required. If the indicated flow rate is outside the manufacturer's specification for zero stability, the meter's zero reading must be adjusted. After the meter's zero has been adjusted, the meter must be proven required by § 3174.11. A copy of the zero value verification procedure must be made available to the AO upon request.

(e) *Required on-site information.* (1) The Coriolis meter display must be readable without using data collection units, laptop computers, or any special equipment, and must be on-site and accessible to the AO.

(2) For each Coriolis meter, the following values and corresponding units of measurement must be displayed:

(i) The instantaneous density of liquid (pounds/bbl, pounds/gal, or degrees API);

(ii) The instantaneous indicated volumetric flow rate through the meter (bbl/day);

(iii) The meter factor;

(iv) The instantaneous pressure (psi);

(v) The instantaneous temperature (°F);

(vi) The cumulative gross standard volume through the meter (non-resettable totalizer) (bbl); and

(vii) The previous day's gross standard volume through the meter (bbl).

(3) The following information must be correct, be maintained in a legible condition, and be accessible to the AO at the FMP without the use of data collection equipment, laptop computers, or any special equipment:

(i) The make, model, and size of each sensor; and

(ii) The make, range, calibrated span, and model of the pressure and temperature transducer used to determine gross standard volume.

(4) A log must be maintained of all meter factors, zero verifications, and zero adjustments. For zero adjustments, the log must include the zero value before adjustment and the zero value after adjustment. The log must be made available upon request.

(f) *Audit trail requirements.* The information specified in paragraphs (f)(1) through (4) of this section must be recorded and retained under the recordkeeping requirements of § 3170.7 of this part. Audit trail requirements must follow API 21.2, Subsection 10 (incorporated by reference, see § 3174.3). All data must be available and submitted to the BLM upon request.

(1) *Quantity transaction record (QTR)*. Follow the requirements for a measurement ticket in § 3174.12(b) of this subpart.

(2) *Configuration log*. The configuration log must comply with the requirements of API 21.2, Subsection 10.2 (incorporated by reference, see § 3174.3). The configuration log must contain and identify all constant flow parameters used in generating the QTR.

(3) *Event log*. The event log must comply with the requirements of API 21.2, Subsection 10.6 (incorporated by reference, see § 3174.3). In addition, the event log must be of sufficient capacity to record all events such that the operator can retain the information under the recordkeeping requirements of § 3170.7 of this part.

(4) *Alarm log* The type and duration of any of the following alarm conditions must be recorded:

(i) Density deviations from acceptable parameters; and

(ii) Instances in which the flow rate exceeded the manufacturer's maximum recommended flow rate or was below the manufacturer's minimum recommended flow rate.

(g) *Data protection*. Each Coriolis meter must have installed and maintained in an operable condition a backup power supply or a nonvolatile memory capable of retaining all data in the unit's memory to ensure that the audit trail information required under paragraph (f) of this section is protected.

§ 3174.11 Meter-proving requirements.

(a) *Applicability*. This section specifies the minimum requirements for conducting volumetric meter proving for all FMP meters.

(b) *Meter prover*. Acceptable provers are positive displacement master meters, Coriolis master meters, and displacement provers. The operator must ensure that the meter prover used to determine the meter factor has a valid certificate of calibration on site and available for review by the AO. The certificate must show that the prover, identified by serial number assigned to and inscribed on the prover, was calibrated as follows:

(1) Master meters must have a meter factor within 0.9900 to 1.0100 determined by a minimum of five consecutive prover runs within 0.0005 (0.05 percent repeatability) as described in API 4.5, Subsection 6.5 (incorporated by reference, see § 3174.3). The master meter must not be mechanically compensated for oil gravity or temperature; its readout must indicate units of volume without corrections. The meter factor must be documented on the calibration certificate and must be calibrated at least once every 12 months. New master meters must be calibrated immediately and recalibrated in three months. Master meters that have undergone mechanical repairs, alterations, or changes that affect the calibration must be calibrated immediately upon completion of this work and calibrated again 3 months after this date under API 4.5, API 4.8, Subsection 10.2, and API 4.8, Annex B (all incorporated by reference, see § 3174.3).

(2) Displacement provers must meet the requirements of API 4.2 (incorporated by reference, see § 3174.3) and be calibrated using the water-draw method under API 4.9.2 (incorporated by reference, see § 3174.3), at the calibration frequencies specified in API 4.8, Subsection 10.1(b) (incorporated by reference, see § 3174.3).

(3) The base prover volume of a displacement prover must be calculated under API 12.2.4 (incorporated by reference, see § 3174.3).

(4) Displacement provers must be sized to obtain a displacer velocity through the prover that is within the appropriate range during proving under API 4.2, Subsection 4.3.4.2, Minimum Displacer Velocities and API 4.2, Subsection 4.3.4.1, Maximum Displacer Velocities (incorporated by reference, see § 3174.3).

(5) Fluid velocity is calculated using API 4.2, Subsection 4.3.4.3, Equation 12 (incorporated by reference, see § 3174.3).

(c) *Meter proving runs*. Meter proving must follow the applicable section(s) of API 4.1, Proving Systems (incorporated by reference, see § 3174.3).

(1) Meter proving must be performed under normal operating fluid pressure, fluid temperature, and fluid type and composition, as follows:

(i) The oil flow rate through the LACT or CMS during proving must be within 10 percent of the normal flow rate;

(ii) The absolute pressure as measured by the LACT or CMS during proving must be within 10 percent of the normal operating absolute pressure;

(iii) The temperature as measured by the LACT or CMS during the proving must be within 10 °F of the normal operating temperature; and

(iv) The gravity of the oil during proving must be within 5° API of the normal oil gravity.

(v) If the normal flow rate, pressure, temperature, or oil gravity vary by more than the limits defined in paragraphs (c)(i) through (c)(iv) of this section, meter provings must be conducted, at a minimum, under the three following conditions: At the lower limit of normal operating conditions, at the upper limit of normal operation conditions, and at the midpoint of normal operating conditions.

(2) If each proving run is not of sufficient volume to generate at least 10,000 pulses, as specified by API 4.2, Subsection 4.3.2 (incorporated by reference, see § 3174.3), from the positive displacement meter or the Coriolis meter, then pulse interpolation must be used in accordance with API 4.6 (incorporated by reference, see § 3174.3).

(3) Proving runs must be made until the calculated meter factor or meter generated pulses from five consecutive runs match within a tolerance of 0.0005 (0.05 percent) between the highest and the lowest value in accordance with API 12.2.3, Subsection 9 (incorporated by reference, see § 3174.3).

(4) The new meter factor is the arithmetic average of the meter generated pulses or intermediate meter factors calculated from the five consecutive runs in accordance with API 12.2.3, Subsection 9 (incorporated by reference, see § 3174.3).

(5) Meter factor computations must follow the sequence described in API 12.2.3 (incorporated by reference, see § 3174.3).

(6) If multiple meters factors are determined over a range of normal operating conditions, then:

(i) If all the meter factors determined over a range of conditions fall within 0.0020 of each other, then a single meter factor may be calculated for that range as the arithmetic average of all the meter factors within that range. The full range of normal operating conditions may be divided into segments such that all the meter factors within each segment fall within a range of 0.0020. In this case, a single meter factor for each segment may be calculated as the arithmetic average of the meter factors within that segment; or

(ii) The metering system may apply a dynamic meter factor derived (using, *e.g.*, linear interpolation, polynomial fit, etc.) from the series of meter factors determined over the range of normal operating conditions, so long as no two neighboring meter factors differ by more than 0.0020.

(7) The meter factor must be at least 0.9900 and no more than 1.0100.

(8) The initial meter factor for a new or repaired meter must be at least 0.9950 and no more than 1.0050.

(9) For positive displacement meters, the back pressure valve may be adjusted after proving only within the normal operating fluid flow rate and fluid pressure as described in paragraph (c)(1) of this section. If the back pressure valve is adjusted after proving, the operator must document the as left fluid flow rate and fluid pressure on the proving report.

(10) If a composite meter factor is calculated, the CPL value must be calculated from the pressure setting of the back pressure valve or the normal operating pressure at the meter. Composite meter factors must not be used with a Coriolis meter.

(d) *Minimum proving frequency*. The operator must prove any FMP meter before removal or sales of production after any of the following events:

(1) Initial meter installation;

(2) Every 3 months (quarterly) after the last proving, or each time the registered volume flowing through the meter, as measured on the non-resettable totalizer from the last proving, increases by 75,000 bbl, whichever comes first, but no more frequently than monthly;

(3) Meter zeroing (Coriolis meter);

(4) Modification of mounting conditions;

(5) A change in fluid temperature that exceeds the transducer's calibrated span;

(6) A change in pressure, density, or flow rate that exceeds the operating proving limits;

(7) The mechanical or electrical components of the meter have been changed, repaired, or removed;

(8) Internal calibration factors have been changed or reprogrammed; or

(9) At the request of the AO.

(e) *Excessive meter factor deviation.* (1) If the difference between meter factors established in two successive provings exceeds ±0.0025, the meter must be immediately removed from service, checked for damage or wear, adjusted or repaired, and reproved before returning the meter to service.

(2) The arithmetic average of the two successive meter factors must be applied to the production measured through the meter between the date of the previous meter proving and the date of the most recent meter proving.

(3) The proving report submitted under paragraph (i) of this section must clearly show the most recent meter factor and describe all subsequent repairs and adjustments.

(f) *Verification of the temperature transducer.* As part of each required meter proving and upon replacement, the temperature averager for a LACT system and the temperature transducer used in conjunction with a CMS must be verified against a known standard according to the following:

(1) The temperature averager or temperature transducer must be compared with a test thermometer traceable to NIST and with a stated accuracy of ±0.25 °F or better.

(2) The temperature reading displayed on the temperature averager or temperature transducer must be compared with the reading of the test thermometer using one of the following methods:

(i) The test thermometer must be placed in a test thermometer well located not more than 12″ from the probe of the temperature averager or temperature transducer; or

(ii) Both the test thermometer and probe of the temperature averager or temperature transducer must be placed in an insulated water bath. The water bath temperature must be within 20 °F of the normal flowing temperature of the oil.

(3) The displayed reading of instantaneous temperature from the temperature averager or the temperature transducer must be compared with the reading from the test thermometer. If they differ by more than 0.5 °F, then the difference in temperatures must be noted on the meter proving report and:

(i) The temperature averager or temperature transducer must be adjusted to match the reading of the test thermometer; or

(ii) The temperature averager or temperature transducer must be recalibrated, repaired, or replaced.

(g) *Verification of the pressure transducer (if applicable).* (1) As part of each required meter proving and upon replacement, the pressure transducer must be compared with a test pressure device (dead weight or pressure gauge) traceable to NIST and with a stated maximum uncertainty of no more than one-half of the accuracy required from the transducer being verified.

(2) The pressure reading displayed on the pressure transducer must be compared with the reading of the test pressure device.

(3) The pressure transducer must be tested at the following three points:

(i) Zero (atmospheric pressure);

(ii) 100 percent of the calibrated span of the pressure transducer; and

(iii) A point that represents the normal flowing pressure through the Coriolis meter.

(4) If the pressure applied by the test pressure device and the pressure displayed on the pressure transducer vary by more than the required accuracy of the pressure transducer, the pressure transducer must be adjusted to read within the stated accuracy of the test pressure device.

(h) *Density verification (if applicable).* As part of each required meter proving, if the API gravity of oil is determined from the average density measured by the Coriolis meter (rather than from a composite sample), then during each proving of the Coriolis meter, the instantaneous flowing density determined by the Coriolis meter must be verified by comparing it with an independent density measurement as specified under API 5.6, Subsection 9.1.2.1 (incorporated by reference, see § 3174.3). The difference between the indicated density determined from the Coriolis meter and the independently determined density must be within the specified density reference accuracy specification of the Coriolis meter. Sampling must be performed in accordance with API 8.1, API 8.2, or API 8.3 (incorporated by reference, see § 3174.3), as appropriate.

(i) *Meter proving reporting requirements.* (1) The operator must report to the AO all meter-proving and volume adjustments after any LACT system or CMS malfunction, including excessive meter-factor deviation, using the appropriate form in either API 12.2.3 or API 5.6 (both incorporated by reference, see § 3174.3), or any similar format showing the same information as the API form, provided that the calculation of meter factors maintains the proper calculation sequence and rounding.

(2) In addition to the information required under paragraph (i)(1) of this section, each meter-proving report must also show the:

(i) Unique meter ID number;

(ii) Lease number, CA number, or unit PA number;

(iii) The temperature from the test thermometer and the temperature from the temperature averager or temperature transducer;

(iv) For pressure transducers, the pressure applied by the pressure test device and the pressure reading from the pressure transducer at the three points required under paragraph (g)(3) of this section;

(v) For density verification (if applicable), the instantaneous flowing density (as determined by Coriolis meter), and the independent density measurement, as compared under paragraph (h) of this section; and

(vi) The "as left" fluid flow rate and fluid pressure, if the back pressure valve is adjusted after proving as described in paragraph (c)(9) of this section.

(3) The operator must submit the meter-proving report to the AO no later than 14 days after the meter proving. The proving report may be either in a hard copy or electronic format.

§ 3174.12 Measurement tickets.

(a) *Tank gauging.* After oil is measured by tank gauging under §§ 3174.5 and 3174.6 of this subpart, the operator, purchaser, or transporter, as appropriate, must complete a uniquely numbered measurement ticket, in either paper or electronic format, with the following information:

(1) Lease, unit PA, or CA number;

(2) Unique tank number and nominal tank capacity;

(3) Opening and closing dates and times;

(4) Opening and closing gauges and observed temperatures in °F;

(5) Observed volume for opening and closing gauge, using tank specific calibration charts (see § 3174.5(c));

(6) Total gross standard volume removed from the tank following API 11.1 (incorporated by reference, see § 3174.3);

(7) Observed API oil gravity and temperature in °F;

(8) API oil gravity at 60 °F, following API 11.1 (incorporated by reference, see § 3174.3);

(9) S&W content percent;

(10) Unique number of each seal removed and installed;

(11) Name of the individual performing the tank gauging; and

(12) Name of the operator.

(b) *LACT system and CMS.* (1) At the beginning of every month, and, unless the operator is using a flow computer under § 3174.10, before conducting proving operations on a LACT system, the operator, purchaser, or transporter, as appropriate, must complete a uniquely numbered measurement ticket, in either paper or electronic format, with the following information:

(i) Lease, unit PA, or CA number;

(ii) Unique meter ID number;

(iii) Opening and closing dates;

(iv) Opening and closing totalizer readings of the indicated volume;

(v) Meter factor, indicating if it is a composite meter factor;

(vi) Total gross standard volume removed through the LACT system or CMS;

(vii) API oil gravity. For API oil gravity determined from a composite sample, the observed API oil gravity and temperature must be indicated in

°F and the API oil gravity must be indicated at 60 °F. For API oil gravity determined from average density (CMS only), the average uncorrected density must be determined by the CMS;

(viii) The average temperature in °F;

(ix) The average flowing pressure in psig;

(x) S&W content percent;

(xi) Unique number of each seal removed and installed;

(xii) Name of the purchaser's representative; and

(xiii) Name of the operator.

(2) Any accumulators used in the determination of average pressure, average temperature, and average density must be reset to zero whenever a new measurement ticket is opened.

§ 3174.13 Oil measurement by other methods.

(a) Any method of oil measurement other than tank gauging, LACT system, or CMS at an FMP requires prior BLM approval.

(b)(1) Any operator requesting approval to use alternate oil measurement equipment or measurement method must submit to the BLM performance data, actual field test results, laboratory test data, or any other supporting data or evidence that demonstrates that the proposed alternate oil equipment or method would meet or exceed the objectives of the applicable minimum requirements of this subpart and would not affect royalty income or production accountability.

(2) The PMT will review the submitted data to ensure that the alternate oil measurement equipment or method meets the requirements of this subpart and will make a recommendation to the BLM to approve use of the equipment or method, disapprove use of the equipment or method, or approve use of the equipment or method with conditions for its use. If the PMT recommends, and the BLM approves new equipment or methods, the BLM will post the make, model, range or software version (as applicable), or method on the BLM Web site *www.blm.gov* as being appropriate for use at an FMP for oil measurement without further approval by the BLM, subject to any conditions of approval identified by the PMT and approved by the BLM.

(c) The procedures for requesting and granting a variance under § 3170.6 of this part may not be used as an avenue for approving new technology, methods, or equipment. Approval of alternative oil measurement equipment or methods may be obtained only under this section.

§ 3174.14 Determination of oil volumes by methods other than measurement.

(a) Under 43 CFR 3162.7–2, when production cannot be measured due to spillage or leakage, the amount of production must be determined by using any method the AO approves or prescribes. This category of production includes, but is not limited to, oil that is classified as slop oil or waste oil.

(b) No oil may be classified or disposed of as waste oil unless the operator can demonstrate to the satisfaction of the AO that it is not economically feasible to put the oil into marketable condition.

(c) The operator may not sell or otherwise dispose of slop oil without prior written approval from the AO. Following the sale or disposal of slop oil, the operator must notify the AO in writing of the volume sold or disposed of and the method used to compute the volume.

§ 3174.15 Immediate assessments.

Certain instances of noncompliance warrant the imposition of immediate assessments upon the BLM's discovery of the violation, as prescribed in the following table. Imposition of any of these assessments does not preclude other appropriate enforcement actions.

TABLE 1 TO § 3174.15—VIOLATIONS SUBJECT TO AN IMMEDIATE ASSESSMENT

Violations subject to an immediate assessment	
Violation:	Assessment amount per violation:
1. Missing or nonfunctioning FMP LACT system components as required by § 3174.8 of this subpart	$1,000

TABLE 1 TO §3174.15—VIOLATIONS SUBJECT TO AN IMMEDIATE ASSESSMENT—Continued

Violations subject to an immediate assessment	
Violation:	Assessment amount per violation:
2. Failure to notify the AO within 72 hours, as required by §3174.7(e) of this subpart, of any FMP LACT system failure or equipment malfunction resulting in use of an unapproved alternate method of measurement	1,000
3. Missing or nonfunctioning FMP CMS components as required by §3174.9 of this subpart	1,000
4. Failure to meet the proving frequency requirements for an FMP, detailed in §3174.11 of this subpart	1,000
5. Failure to obtain a written approval, as required by §3174.13 of this subpart, before using any oil measurement method other than tank gauging, LACT system, or CMS at a FMP	1,000

Subpart 3175—Measurement of Gas

SOURCE: 81 FR 81609, Nov. 17, 2016, unless otherwise noted.

§3175.10 Definitions and acronyms.

(a) As used in this subpart, the term:

AGA Report No. (followed by a number) means a standard prescribed by the American Gas Association, with the number referring to the specific standard.

Area ratio means the smallest unrestricted area at the primary device divided by the cross-sectional area of the meter tube. For example, the area ratio (A_r) of an orifice plate is the area of the orifice bore (A_d) divided by the area of the meter tube (A_D). For an orifice plate with a bore diameter (d) of 1.000 inches in a meter tube with an inside diameter (D) of 2.000 inches the area ratio is 0.25 and is calculated as follows:

$$A_d = \frac{\pi d^2}{4} = \frac{\pi \cdot 1.000^2}{4} = 0.7854in^2 \quad A_D = \frac{\pi D^2}{4} = \frac{\pi \cdot 2.000^2}{4} = 3.1416in^2$$

$$A_r = \frac{A_d}{A_D} = \frac{0.7854in^2}{3.1416in^2} = 0.25$$

As-found means the reading of a mechanical or electronic transducer when compared to a certified test device, prior to making any adjustments to the transducer.

As-left means the reading of a mechanical or electronic transducer when compared to a certified test device, after making adjustments to the transducer, but prior to returning the transducer to service.

Atmospheric pressure means the pressure exerted by the weight of the atmosphere at a specific location.

Beta ratio means the measured diameter of the orifice bore divided by the measured inside diameter of the meter tube. This is also referred to as a diameter ratio.

Bias means a systematic shift in the mean value of a set of measurements away from the true value of what is being measured.

British thermal unit (Btu) means the amount of heat needed to raise the temperature of one pound of water by 1 °F.

Component-type electronic gas measurement system means an electronic gas measurement system comprising transducers and a flow computer, each identified by a separate make and model, from which performance specifications are obtained.

Configuration log means a list of all fixed or user-programmable parameters used by the flow computer that could