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Part 250 —Oil and Gas and Sulphur Operations in the Outer Continental Shelf

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Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security

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§ 250.1201 Definitions.

Terms not defined in this section have the meanings given in the applicable chapter of the API MPMS, which is incorporated by reference in § 250.198. Terms used in Subpart L have the following meaning:

Allocation meter —a meter used to determine the portion of hydrocarbons attributable to one or more platforms, leases, units, or wells, in relation to the total production from a royalty or allocation measurement point.

British Thermal Unit (Btu) —the amount of heat needed to raise the temperature of one pound of water from 59.5 degrees Fahrenheit (59.5 °F) to 60.5 degrees Fahrenheit (60.5 °F) at standard pressure base (14.73 pounds per square inch absolute (psia)).

Compositional Analysis —separating mixtures into identifiable components expressed in mole percent.

Force majeure event —an event beyond your control such as war, act of terrorism, crime, or act of nature which prevents you from operating the wells and meters on your OCS facility.

Gas lost —gas that is neither sold nor used on the lease or unit nor used internally by the producer.

Gas processing plant —an installation that uses any process designed to remove elements or compounds (hydrocarbon and non-hydrocarbon) from gas, including absorption, adsorption, or refrigeration. Processing does not include treatment operations, including those necessary to put gas into marketable conditions such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, desulphurization, and compression. The changing of pressures or temperatures in a reservoir is not processing.

Gas processing plant statement —a monthly statement showing the volume and quality of the inlet or field gas stream and the plant products recovered during the period, volume of plant fuel, flare and shrinkage, and the allocation of these volumes to the sources of the inlet stream.

Gas royalty meter malfunction —an error in any component of the gas measurement system which exceeds contractual tolerances.

Gas volume statement —a monthly statement showing gas measurement data, including the volume (Mcf) and quality (Btu) of natural gas which flowed through a meter.

Inventory tank —a tank in which liquid hydrocarbons are stored prior to royalty measurement. The measured volumes are used in the allocation process.

Liquid hydrocarbons (free liquids) —hydrocarbons which exist in liquid form at standard conditions after passing through separating facilities.

Malfunction factor —a liquid hydrocarbon royalty meter factor that differs from the previous meter factor by an amount greater than 0.0025.

Natural gas —a highly compressible, highly expandable mixture of hydrocarbons which occurs naturally in a gaseous form and passes a meter in vapor phase.

Operating meter —a royalty or allocation meter that is used for gas or liquid hydrocarbon measurement for any period during a calibration cycle.

Pipeline (retrograde) condensate —liquid hydrocarbons which drop out of the separated gas stream at any point in a pipeline during transmission to shore.

Pressure base —the pressure at which gas volumes and quality are reported. The standard pressure base is 14.73 psia.

Prove —to determine (as in meter proving) the relationship between the volume passing through a meter at one set of conditions and the indicated volume at those same conditions.

Royalty meter —a meter approved for the purpose of determining the volume of gas, oil, or other components removed, saved, or sold from a Federal lease.

Royalty tank —an approved tank in which liquid hydrocarbons are measured and upon which royalty volumes are based.

Run ticket —the invoice for liquid hydrocarbons measured at a royalty point.

Sales meter —a meter at which custody transfer takes place (not necessarily a royalty meter).

Seal —a device or approved method used to prevent tampering with royalty measurement components.

Standard conditions —atmospheric pressure of 14.73 pounds per square inch absolute (psia) and 60 °F.

Surface commingling —the surface mixing of production from two or more leases and/or unit participating areas prior to royalty measurement.

Temperature base —the temperature at which gas and liquid hydrocarbon volumes and quality are reported. The standard temperature base is 60 °F.

Verification/Calibration —testing and correcting, if necessary, a measuring device to ensure compliance with industry accepted, manufacturer's recommended, or regulatory required standard of accuracy.

You or your —the lessee or the operator or other lessees' representative engaged in operations in the Outer Continental Shelf (OCS).

[76 FR 64462, Oct. 18, 2011, as amended at 91 FR 35360, June 10, 2026]

§ 250.1202 Liquid hydrocarbon measurement.

(a) ***What are the requirements for measuring liquid hydrocarbons?*** You must:

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing liquid hydrocarbon production, or making any changes to the previously-approved measurement and/or allocation procedures. Your application (which may also include any relevant gas measurement and surface commingling requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity as shown in the following table.

Application type	Actions
(i) Simple applications,	Applications to temporarily reroute production (for a duration not to exceed six months); Production tests prior to pipeline construction; Departures related to meter proving, well testing, or sampling frequency.
(ii) Complex applications,	Creation of new facility measurement points (FMPs); Association of leases or units with existing FMPs; Inclusion of production from additional structures; Meter updates which add buy-back gas meters or pigging meters; Other applications which request deviations from the approved allocation procedures.

(2) Use measurement equipment and procedures that will accurately measure the liquid hydrocarbons produced from a lease or unit according to the following API publications unless otherwise approved by the Regional Supervisor:

(i) API MPMS Chapter 2, Section 2A (incorporated by reference, see § 250.198);

(ii) API MPMS Chapter 2, Section 2B (incorporated by reference, see § 250.198);

(iii) API MPMS Chapter 3.1A (incorporated by reference, see § 250.198);

(iv) API MPMS Chapter 3, Section 1B (incorporated by reference, see § 250.198);

(v) API MPMS Chapter 4, Section 1 (incorporated by reference, see § 250.198);

(vi) API MPMS Chapter 4, Section 2 (incorporated by reference, see § 250.198);

(vii) API MPMS Chapter 4, Section 4 (incorporated by reference, see § 250.198);

(viii) API MPMS Chapter 4.5 (incorporated by reference, see § 250.198);

(ix) API MPMS Chapter 4, Section 6 (incorporated by reference, see § 250.198).;

(x) API MPMS Chapter 4, Section 7 (incorporated by reference, see § 250.198);.

(xi) API MPMS Chapter 4.8 (incorporated by reference, see § 250.198);

(xii) API MPMS Chapter 4, Section 9, Part 2 (incorporated by reference, see § 250.198);

(xiii) API MPMS Chapter 5, Section 1 (incorporated by reference, see § 250.198);

(xiv) API MPMS Chapter 5, Section 2 (incorporated by reference, see § 250.198);

(xv) API MPMS Chapter 5, Section 3 (incorporated by reference, see § 250.198);

(xvi) API MPMS Chapter 5, Section 4 (incorporated by reference, see § 250.198);

(xvii) API MPMS Chapter 5, Section 5 (incorporated by reference, see § 250.198);

(xviii) API MPMS Chapter 5, Section 6 (incorporated by reference, see§ 250.198);

(xix) API MPMS Chapter 5.8 (incorporated by reference, see § 250.198);

(xx) API MPMS Chapter 6.1 (incorporated by reference, see § 250.198);

(xxi) API MPMS Chapter 6, Section 6 (incorporated by reference, see § 250.198);

(xxii) API MPMS Chapter 6, Section 7 (incorporated by reference, see § 250.198);

(xxiii) API MPMS Chapter 7.1 (incorporated by reference, see § 250.198);

(xxiv) API MPMS Chapter 7.3 (incorporated by reference, see § 250.198);

(xxv) API MPMS Chapter 8.1 (incorporated by reference, see § 250.198);

(xxvi) API MPMS Chapter 8.2 (incorporated by reference, see § 250.198);

(xxvii) API MPMS Chapter 8.3 (incorporated by reference, see § 250.198);

(xxviii) API MPMS Chapter 9.1 (incorporated by reference, see § 250.198);

(xxix) API MPMS Chapter 9.2 (incorporated by reference, see § 250.198);

(xxx) API MPMS Chapter 9.4 (incorporated by reference, see § 250.198);

(xxxi) API MPMS Chapter 10, Section 1 (incorporated by reference, see § 250.198);

(xxxii) API MPMS Chapter 10.2 (incorporated by reference, see § 250.198);

(xxxiii) API MPMS Chapter 10.3 (incorporated by reference, see § 250.198);

(xxxiv) API MPMS Chapter 10.4 (incorporated by reference, see § 250.198);

(xxxv) API MPMS Chapter 10.9 (incorporated by reference, see § 250.198);

(xxxvi) API MPMS Chapter 11, Section 1 (incorporated by reference, see § 250.198);

(xxxvii) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference, see § 250.198);

(xxxviii) API MPMS Chapter 12.2 (incorporated by reference, see § 250.198). You may temporarily continue to use API MPMS Chapter 12, Section 2, Part 1, API MPMS Chapter 12, Section 2, Part 2, and API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference, see § 250.198) for flow computer systems at BSEE designated facility measurement points (FMP) in existence as of August 10, 2026. However, you must comply with API MPMS Chapter 12.2 at these FMPs commencing August 11, 2031 unless otherwise approved by the Regional Supervisor;

(xxxix) API MPMS Chapter 20, Section 1, excluding sections 1.16.1, 1.16.3, 1.16.3.1, 1.16.3.2, and 1.16.3.3, (incorporated by reference, see § 250.198);

(xl) API MPMS Chapter 21, Section 2 (incorporated by reference, see § 250.198);

(xli) API MPMS Chapter 21, Addendum to Section 2, Part 2 (incorporated by reference, see § 250.198);

(xlii) API Standard 2555 (incorporated by reference, see § 250.198);

(xliii) API Recommended Practice 2556 (incorporated by reference, see § 250.198); and

(xliv) API MPMS Chapter 11.1 (incorporated by reference, see § 250.198).

(3) Use procedures and correction factors according to the following API MPMS publications.

(i) API MPMS Chapter 4.8 (incorporated by reference, see § 250.198);

(ii) API MPMS Chapter 5, Section 6 (incorporated by reference, see § 250.198);

(iii) API MPMS Chapter 5.8 (incorporated by reference, see § 250.198);

(iv) API MPMS Chapter 11, Section 1 (incorporated by reference, see § 250.198);

(v) API MPMS Chapter 11.2.2 (incorporated by reference, see § 250.198);

(vi) API MPMS Chapter 11, Section 2, Part 2 (incorporated by reference, see § 250.198);

(vii) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference, see § 250.198); and

(viii) API MPMS Chapter 11.1 (incorporated by reference, see § 250.198).

(4) When requested by the Regional Supervisor, provide the pipeline (retrograde) condensate volumes as allocated to the individual leases or units.

(b) ***What are the requirements for liquid hydrocarbon royalty meters?*** You must:

(1) Ensure that the royalty meter facilities include the following approved components (or other BSEE-approved components) which must be compatible with their connected systems:

(i) A meter equipped with a nonreset totalizer;

(ii) A calibrated mechanical displacement (pipe) prover, master meter, or tank prover;

(iii) A proportional-to-flow sampling device pulsed by the meter output;

(iv) A temperature measurement or temperature compensation device; and

(v) A sediment and water monitor with a probe located upstream of the divert valve.

(2) Ensure that the royalty meter facilities accomplish the following:

(i) Prevent flow reversal through the meter;

(ii) Protect meters subjected to pressure pulsations or surges;

(iii) Prevent the meter from being subjected to shock pressures greater than the maximum working pressure; and

(iv) Prevent meter bypassing.

(3) Maintain royalty meter facilities to ensure the following:

(i) Meters operate within the gravity range specified by the manufacturer;

(ii) Meters operate within the manufacturer's specifications for maximum and minimum flow rate for linear accuracy; and

(iii) Meters are reproven when changes in metering conditions affect the meters' performance such as changes in pressure, temperature, density (water content), viscosity, pressure, and flow rate.

(4) Ensure that sampling devices conform to the following:

(i) The sampling point is in the flowstream immediately upstream or downstream of the meter or divert valve in accordance with API MPMS Chapter 8.2 (incorporated by reference, see § 250.198) unless otherwise approved by the Regional Supervisor;

(ii) The sample container is vapor-tight and includes a power mixing device to allow complete mixing of the sample before removal from the container; and

(iii) The sample probe is in the center half of the pipe diameter in a vertical run and is located at least three pipe diameters downstream of any pipe fitting within a region of turbulent flow. The sample probe can be located in a horizontal pipe if adequate stream conditioning such as power mixers or static mixers are installed upstream of the probe according to the manufacturer's instructions.

(c) ***What are the requirements for run tickets?*** You must:

(1) For royalty meters, ensure that the run tickets clearly identify all observed data, all correction factors not included in the meter factor, and the net standard volume.

(2) For royalty tanks, ensure that the run tickets clearly identify all observed data, all applicable correction factors, on/off seal numbers, and the net standard volume.

(3) Pull a run ticket at the beginning of the month and immediately after establishing the monthly meter factor or a malfunction meter factor.

(4) Send all run tickets for royalty meters and tanks to the Regional Supervisor within 15 days after the end of the month;

(d) ***What are the requirements for liquid hydrocarbon royalty meter provings?*** You must:

(1) Permit BSEE representatives to witness provings;

(2) Ensure that the integrity of the prover calibration is traceable to test measures certified by the National Institute of Standards and Technology;

(3) Prove each operating royalty meter to determine the meter factor monthly, but the time between meter factor determinations must not exceed 42 days. When a force majeure event precludes the required monthly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved monthly thereafter, but the time between meter factor determinations must not exceed 42 days;

(4) Obtain approval from the Regional Supervisor before proving on a schedule other than monthly; and

(5) Submit copies of all meter proving reports for royalty meters to the Regional Supervisor monthly within 15 days after the end of the month.

(e) ***What are the requirements for calibrating a master meter used in royalty meter provings?*** You must:

(1) Calibrate the master meter to obtain a master meter factor before using it to determine operating meter factors;

(2) Use a fluid of similar gravity, viscosity, temperature, and flow rate as the liquid hydrocarbons that flow through the operating meter to calibrate the master meter;

(3) Calibrate the master meter monthly, but the time between calibrations must not exceed 42 days;

(4) Calibrate the master meter by recording runs until the results of two consecutive runs (if a tank prover is used) or five out of six consecutive runs (if a mechanical-displacement prover is used) produce meter factor differences of no greater than 0.0002. Lessees must use the average of the two (or the five) runs that produced acceptable results to compute the master meter factor;

(5) Install the master meter upstream of any back-pressure or reverse flow check valves associated with the operating meter. However, the master meter may be installed either upstream or downstream of the operating meter; and

(6) Keep a copy of the master meter calibration report at your field location for 2 years.

(f) ***What are the requirements for calibrating mechanical-displacement provers and tank provers?*** You must:

(1) Calibrate mechanical-displacement provers and tank provers at least once every 5 years according to the following API MPMS publications:

(i) API MPMS Chapter 4, Section 4 (incorporated by reference, see § 250.198);

(ii) API MPMS Chapter 4.8 (incorporated by reference, see § 250.198); and

(iii) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference, see § 250.198).

(2) Submit a copy of each calibration report to the Regional Supervisor within 15 days after the calibration.

(g) ***What correction factors must I use when proving meters with a mechanical-displacement prover, tank prover, or master meter?*** Calculate the correction factors using the following API MPMS publications (incorporated by reference, see § 250.198):

(1) API MPMS Chapter 4.8 (incorporated by reference, see § 250.198);

(2) API MPMS Chapter 11, Section 1 (incorporated by reference, see § 250.198);

(3) API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference, see § 250.198); and

(4) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference, see § 250.198).

(h) *What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?*

(1) If you use a mechanical-displacement prover, you must record proof runs until five out of six consecutive runs produce a difference between individual runs of no greater than .05 percent. You must use the average of the five accepted runs to compute the meter factor.

(2) If you use a master meter, you must record proof runs until three consecutive runs produce a total meter factor difference of no greater than 0.0005. The flow rate through the meters during the proving must be within 10 percent of the rate at which the line meter will operate. The final meter factor is determined by averaging the meter factors of the three runs;

(3) If you use a tank prover, you must record proof runs until two consecutive runs produce a meter factor difference of no greater than .0005. The final meter factor is determined by averaging the meter factors of the two runs; and

(4) You must apply operating meter factors forward starting with the date of the proving.

(5) Proving systems that employ the dual chronometry method of pulse interpolation must be compliant with API MPMS Chapter 4, Section 6 (incorporated by reference, see § 250.198) unless otherwise approved by the Regional Supervisor.

(i) *Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must I do?*

(1) If the difference between the meter factor and the previous factor exceeds 0.0025 it is a malfunction factor, and you must:

(i) Remove the meter from service and inspect it for damage or wear;

(ii) Adjust or repair the meter, and reprove it;

(iii) Apply the average of the malfunction factor and the previous factor to the production measured through the meter between the date of the previous factor and the date of the malfunction factor; and

(iv) Indicate that a meter malfunction occurred and show all appropriate remarks regarding subsequent repairs or adjustments on the proving report.

(2) If a meter fails to register production, you must:

(i) Remove the meter from service, repair and reprove it;

(ii) Apply the previous meter factor to the production run between the date of that factor and the date of the failure; and

(iii) Estimate and report unregistered production on the run ticket.

(3) If the results of a royalty meter proving exceed the run tolerance criteria and all measures excluding the adjustment or repair of the meter cannot bring results within tolerance, you must:

(i) Establish a factor using proving results made before any adjustment or repair of the meter; and

(ii) Treat the established factor like a malfunction factor (see paragraph (i)(1) of this section).

(j) ***How must I correct gross liquid hydrocarbon volumes to standard conditions?*** To correct gross liquid hydrocarbon volumes to standard conditions, you must:

(1) Include Cpl factors in the meter factor calculation or list and apply them on the appropriate run ticket.

(2) List Ctl factors on the appropriate run ticket when the meter is not automatically temperature compensated.

(k) ***What are the requirements for liquid hydrocarbon allocation meters?*** For liquid hydrocarbon allocation meters you must:

(1) Take samples continuously proportional to flow, or daily, using the procedures in API MPMS Chapter 8.1 or API MPMS Chapter 8.2 (both incorporated by reference, see § 250.198).

(2) For turbine meters, take the sample proportional to the flow only;

(3) Prove operating allocation meters monthly if they measure 50 or more barrels per day per meter the previous month. When a force majeure event precludes the required monthly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved monthly thereafter; or

(4) Prove operating allocation meters quarterly if they measure less than 50 barrels per day per meter the previous month. When a force majeure event precludes the required quarterly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved quarterly thereafter;

(5) Keep a copy of the proving reports at the field location for 2 years;

(6) Adjust and reprove the meter if the meter factor differs from the previous meter factor by more than 2 percent and less than 7 percent;

(7) For turbine meters, remove from service, inspect and reprove the meter if the factor differs from the previous meter factor by more than 2 percent and less than 7 percent;

(8) Repair and reprove, or replace and prove the meter if the meter factor differs from the previous meter factor by 7 percent or more; and

(9) Permit BSEE representatives to witness provings.

(l) ***What are the requirements for royalty and inventory tank facilities?*** You must:

(1) Equip each royalty and inventory tank with a vapor-tight thief hatch, a vent-line valve, and a fill line designed to minimize free fall and splashing;

(2) For royalty tanks, submit a complete set of calibration charts (tank tables) to the Regional Supervisor before using the tanks for royalty measurement;

(3) For inventory tanks, retain the calibration charts for as long as the tanks are in use and submit them to the Regional Supervisor upon request; and

(4) Obtain the volume and other measurement parameters by using corrections factors and procedures in the following API MPMS publications (all incorporated by reference, see § 250.198):

(i) API MPMS Chapter 2, Section 2A;

(ii) API MPMS Chapter 2, Section 2B;

(iii) API MPMS Chapter 3.1A;

(iv) API MPMS Chapter 3, Section 1B; and

(v) API MPMS Chapter 11, Section 1.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 18921, Mar. 29, 2012; 91 FR 35360, June 10, 2026]

§ 250.1203 Gas measurement.

(a) ***To which meters do BSEE requirements for gas measurement apply?*** BSEE requirements for gas measurements apply to all OCS gas royalty and allocation meters.

(b) ***What are the requirements for measuring gas?*** You must:

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing gas production, or making any changes to the previously-approved measurement and/or allocation procedures. Your application (which may also include any relevant liquid hydrocarbon measurement and surface commingling requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity, see table in § 250.1202(a)(1).

(2) Design, install, use, maintain, and test measurement equipment and procedures to ensure accurate and verifiable measurement. You must follow the recommendations in the following API MPMS, GPA, and AGA publications unless otherwise approved by the Regional Supervisor:

(i) AGA Report No. 7 (incorporated by reference, see § 250.198);

(ii) AGA Report No. 8, Part 1 (incorporated by reference, see § 250.198);

(iii) AGA Report No. 8, Part 2 (incorporated by reference, see § 250.198);

(iv) AGA Report No. 9 (incorporated by reference, see § 250.198);

(v) AGA Report No. 10 (incorporated by reference, see § 250.198);

(vi) AGA Report No. 11 (incorporated by reference, see § 250.198);

(vii) GPA Standard 2198-16 (incorporated by reference, see § 250.198);

(viii) GPA Standard 2261-20 (incorporated by reference, see § 250.198);

(ix) GPA Standard 2286-14 (incorporated by reference, see § 250.198);

(x) API MPMS Chapter 14.1 (incorporated by reference, see § 250.198);

(xi) API MPMS Chapter 14.3.1 (incorporated by reference, see § 250.198);

(xii) API MPMS Chapter 14.3.2 (incorporated by reference, see § 250.198);

(xiii) API MPMS Chapter 14.3.3 (incorporated by reference, see § 250.198);

(xiv) API MPMS Chapter 14.5/GPA Standard 2172-09 (incorporated by reference, see § 250.198);

(xv) API MPMS Chapter 14, Section 8 (incorporated by reference, see § 250.198);

(xvi) API MPMS Chapter 20, Section 1, excluding sections 1.16.1, 1.16.3, 1.16.3.1, 1.16.3.2, and 1.16.3.3, (incorporated by reference, see § 250.198);

(xvii) API MPMS Chapter 20.3 (incorporated by reference, see § 250.198); and

(xviii) API MPMS Chapter 21, Section 1 (incorporated by reference, see § 250.198).

(3) Ensure that the measurement components demonstrate consistent levels of accuracy throughout the system.

(4) Equip the meter with a chart or electronic data recorder. If an electronic data recorder is used, you must follow the recommendations in API MPMS Chapter 21, Section 1 (incorporated by reference, see § 250.198).

(5) Take proportional-to-flow or spot samples upstream or downstream of the meter at least once every 6 months.

(6) When requested by the Regional Supervisor, provide available information on the gas quality.

(7) Ensure that standard conditions for reporting gross heating value (Btu) are at a base temperature of 60 °F and at a base pressure of 14.73 psia and reflect the same degree of water saturation as in the gas volume.

(8) When requested by the Regional Supervisor, submit copies of gas volume statements for each requested gas meter. Show whether gas volumes and gross Btu heating values are reported at saturated or unsaturated conditions; and

(9) When requested by the Regional Supervisor, provide volume and quality statements on dispositions other than those on the gas volume statement.

(c) ***What are the requirements for gas meter calibrations?*** You must:

(1) Verify/calibrate operating meters monthly, but do not exceed 42 days between verifications/calibrations. When a force majeure event precludes the required monthly meter verification/calibration, meters must be verified/calibrated within 15 days after being returned to service. The meters must be verified/calibrated monthly thereafter, but do not exceed 42 days between meter verifications/calibrations;

(2) Calibrate each meter by using the manufacturer's specifications;

(3) Conduct calibrations as close as possible to the average hourly rate of flow since the last calibration;

(4) Retain calibration reports at the field location for 2 years, and send the reports to the Regional Supervisor upon request; and

(5) Permit BSEE representatives to witness calibrations.

(d) ***What must I do if a gas meter is out of calibration or malfunctioning?*** If a gas meter is out of calibration or malfunctioning, you must:

(1) If the readings are greater than the contractual tolerances, adjust the meter to function properly or remove it from service and replace it.

(2) Correct the volumes to the last acceptable calibration as follows:

(i) If the duration of the error can be determined, calculate the volume adjustment for that period.

(ii) If the duration of the error cannot be determined, apply the volume adjustment to one-half of the time elapsed since the last calibration or 21 days, whichever is less.

(e) *What are the requirements when natural gas from a Federal lease on the OCS is transferred to a gas plant before royalty determination?* If natural gas from a Federal lease on the OCS is transferred to a gas plant before royalty determination:

(1) You must provide the following to the Regional Supervisor upon request:

(i) A copy of the monthly gas processing plant allocation statement; and

(ii) Gross heating values of the inlet and residue streams when not reported on the gas plant statement.

(2) You must permit BSEE to inspect the measurement and sampling equipment of natural gas processing plants that process Federal production.

(f) *What are the requirements for measuring gas lost or used on a lease?*

(1) You must either measure or estimate the volume of gas lost or used on a lease.

(2) If you measure the volume, document the measurement equipment used and include the volume measured.

(3) If you estimate the volume, document the estimating method, the data used, and the volumes estimated.

(4) You must keep the documentation, including the volume data, easily obtainable for inspection at the field location for at least 2 years, and must retain the documentation at a location of your choosing for at least 7 years after the documentation is generated, subject to all other document retention and production requirements in 30 U.S.C. 1713 and 30 CFR part 1212.

(5) Upon the request of the Regional Supervisor, you must provide copies of the records.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 18922, Mar. 29, 2012; 85 FR 84237, Dec. 28, 2020; 91 FR 35361, June 10, 2026]

§ 250.1204 Surface commingling.

(a) *What are the requirements for the surface commingling of production?* You must:

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing the commingling of production or making any changes to the previously approved commingling procedures. Your application (which may also include any relevant liquid hydrocarbon and gas measurement requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity, see table in § 250.1202(a)(1).

(2) Upon the request of the Regional Supervisor, lessees who deliver State lease production into a Federal commingling system must provide volumetric or fractional analysis data on the State lease production through the designated system operator.

(b) *What are the requirements for a periodic well test used for allocation?* You must:

(1) Conduct a well test at least once every 60 days (unless otherwise approved by the Regional Supervisor) in accordance with the recommendations and guidelines provided in API MPMS Chapter 20.5 (incorporated by reference, see § 250.198). When a force majeure event precludes the required well test within the prescribed 60 day period (or other frequency approved by the Regional Supervisor), wells must be tested within 15 days after being returned to production. Thereafter, well tests must be conducted at least once every 60 days (or other frequency approved by the Regional Supervisor);

(2) Follow the well test procedures in 30 CFR part 250, subpart K; and

(3) Retain the well test data at the field location for 2 years.

[76 FR 64462, Oct. 18, 2011, as amended at 91 FR 35361, June 10, 2026]

§ 250.1205 Site security.

(a) ***What are the requirements for site security?*** You must:

(1) Protect Federal production against production loss or theft;

(2) Post a sign at each royalty or inventory tank which is used in the royalty determination process. The sign must contain the name of the facility operator, the size of the tank, and the tank number;

(3) Not bypass BSEE-approved liquid hydrocarbon royalty meters and tanks; and

(4) Report the following to the Regional Supervisor as soon as possible, but no later than the next business day after discovery:

(i) Theft or mishandling of production;

(ii) Tampering or bypassing any component of the royalty measurement facility; and

(iii) Falsifying production measurements.

(b) ***What are the requirements for using seals?*** You must:

(1) Seal the following components of liquid hydrocarbon royalty meter installations to ensure that tampering cannot occur without destroying the seal:

(i) Meter component connections from the base of the meter up to and including the register;

(ii) Sampling systems including packing device, fittings, sight glass, and container lid;

(iii) Temperature and gravity compensation device components;

(iv) All valves on lines leaving a royalty or inventory storage tank, including load-out line valves, drain-line valves, and connection-line valves between royalty and non-royalty tanks; and

(v) Any additional components required by the Regional Supervisor.

(2) Seal all bypass valves of gas royalty and allocation meters.

(3) Number and track the seals and keep the records at the field location for at least 2 years; and

(4) Make the records of seals available for BSEE inspection.