§ 250.1202  

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).

§ 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.

<table>
<thead>
<tr>
<th>Application type</th>
<th>Actions</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i) Simple applications,</td>
<td>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.</td>
</tr>
<tr>
<td>(ii) Complex applications,</td>
<td>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.</td>
</tr>
</tbody>
</table>

(2) Use measurement equipment and procedures that will accurately measure the liquid hydrocarbons produced from a lease or unit to comply with the
following additional API MPMS industry standards or API RP:

(i) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);

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

(iii) API MPMS, Chapter 5, Section 8 (incorporated by reference as specified in §250.198);

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

(v) API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference as specified in §250.198);

(vi) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §250.198);

(vii) API MPMS, Chapter 21, Section 2 (incorporated by reference as specified in §250.198);

(viii) API MPMS, Chapter 21, Addendum to Section 2 (incorporated by reference as specified in §250.198);

(ix) API RP 86 (incorporated by reference as specified in §250.198);

(3) Use procedures and correction factors according to the applicable chapters of the API MPMS or RP as incorporated by reference in 30 CFR 250.198, including the following additional editions:

(i) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);

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

(iii) API MPMS, Chapter 5, Section 8 (incorporated by reference as specified in §250.198);

(iv) API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference as specified in §250.198);

(v) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §250.198);

(vi) API RP 86 (incorporated by reference as specified in §250.198); when obtaining net standard volume and associated measurement parameters; and

(iv) 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 the API MPMS (as incorporated by reference in §250.198);

(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 API MPMS as incorporated by reference in 30 CFR 250.198, including the following additional editions:
   (i) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);
   (ii) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §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 following correction factors using the API MPMS as
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.

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).

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.

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 (use the procedure in the applicable chapter of the API MPMS as incorporated by reference in §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
§ 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 API MPMS or RP and AGA as incorporated by reference in 30 CFR 250.198, including the following additional editions:

(i) API RP 86 (incorporated by reference as specified in § 250.198);

(ii) AGA Report No. 7 (incorporated by reference as specified in § 250.198);

(iii) AGA Report No. 9 (incorporated by reference as specified in § 250.198);

(iv) AGA Report No. 10 (incorporated by reference as specified in § 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.

(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...