DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 3160 and 3170

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RIN 1004–AE16

Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Oil

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rule.

SUMMARY: This final rule updates and replaces Onshore Oil and Gas Order Number 4, Measurement of Oil (Order 4) with new regulations codified in the Code of Federal Regulations (CFR). It establishes minimum standards for the measurement of oil produced from Federal and Indian (except Osage Tribe) leases to ensure that production is accurately measured and properly accounted for.

DATES: The final rule is effective on January 17, 2017. The incorporation by reference (IBR) of certain publications listed in the rule is approved by the Director of the Federal Register as of January 17, 2017.

ADDRESSES: *Mail:* U.S. Department of the Interior, Director (630), Bureau of Land Management, Mail Stop 2134 LM, 1849 C St. NW., Washington, DC 20240, Attention: 1004–AE16.

Personal or messenger delivery: 20 M Street SE., Room 2134LM, Washington, DC 20003.

FOR FURTHER INFORMATION CONTACT: Mike McLaren, Petroleum Engineer, BLM Wyoming, Pinedale Field Office, 1625 West Pine St., P.O. Box 768, Pinedale, WY 82941, or by telephone at 307–367–5389, for information about the requirements of this final rule; or Steven Wells, Division Chief, Fluid Minerals Division, 202–912–7143, for information regarding the Bureau of Land Management's (BLM's) Fluid Minerals Program. For questions related to regulatory process issues, please contact Faith Bremner at 202–912–7441. Persons who use a telecommunications device for the deaf (TDD) may call the Federal Relay Service at 800–877–8339 to contact the above individuals during normal business hours. The Service is available 24 hours a day, 7 days a week to leave a message or question with the above individuals. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

I. Overview and Background

The BLM developed this rule based on the proposed rule published in the **Federal Register** on September 30, 2015 (80 FR 58952), and the BLM's consideration of tribal and public comments received on the proposed rule. This final rule strengthens the BLM's policies governing production accountability by updating its minimum standards for oil measurement to reflect the considerable changes in technology and industry practices that have occurred in the 25 years since Order 4 was issued. It also responds to recommendations the United States Government Accountability Office (GAO), the Department of the Interior's (Interior's or Department's) Office of the Inspector General (OIG), and the Secretary of the Interior's (Secretary's) Royalty Policy Committee (RPC), Subcommittee on Royalty Management (Subcommittee) made with respect to the BLM's production verification efforts. As explained in this preamble, the overall volume uncertainty and performance goals established by this rule are designed to ensure that the oil volume reported on an Oil and Gas Operations Report (OGOR) submitted to the Office of Natural Resources Revenue (ONRR) is sufficiently accurate to ensure that the royalties due are paid.

Like the proposed rule, the final rule addresses the use of new oil meter technology, proper measurement documentation, and recordkeeping; establishes performance standards for oil measurement systems; and includes a mechanism for the BLM to review, and approve for use, new oil measurement technology and systems. The final rule expands the acts of noncompliance that would result in an immediate assessment. Finally, it sets forth a process for the BLM to consider variances from these requirements.

Key changes incorporated into the final rule include provisions that allow operators to use Coriolis measurement systems (CMSs) and automatic tank gauging (ATG) systems without having to obtain variances from the BLM.

This final rule, as well as the final rules to update and replace Onshore Oil and Gas Orders Numbers 3 (Order 3) and 5 (Order 5) related to site security and the measurement of gas, respectively, enhance the BLM's overall production verification and accountability program.

The Secretary has the authority under various Federal and Indian mineral leasing laws to manage oil and gas operations on Federal and Indian (except Osage Tribe) lands. Governing laws include, but are not limited to, the Mineral Leasing Act (MLA), 30 U.S.C. 181 *et seq.;* the Mineral Leasing Act for Acquired Lands, 30 U.S.C. 351 *et seq.;* the Federal Oil and Gas Royalty Management Act (FOGRMA), 30 U.S.C. 1701 *et seq.;* the Indian Mineral Leasing Act, 25 U.S.C. 396a *et seq.;* the Act of March 3, 1909, 25 U.S.C. 396; the Indian Mineral Development Act, 25 U.S.C. 2101 *et seq.;* and the Federal Land Policy and Management Act (FLPMA), 43 U.S.C. 1701, *et seq.*[1]

The BLM's onshore oil and gas program is one of the most significant mineral-leasing programs in the Federal Government. In the fiscal year (FY) 2015 sales year, onshore Federal oil and gas lease holders sold 180 million barrels of oil,[2] 2.5 trillion cubic feet of natural gas,[3] and 2.6 billion gallons of natural gas liquids, with a market value of more than $17.7 billion, and generating royalties of almost $2 billion. Nearly half of these revenues were distributed to the States in which the leases are located. Lease holders on tribal and Indian lands sold 59 million barrels of oil, 239 billion cubic feet of natural gas, and 182 million gallons of natural gas liquids, with a market value of over $3.6 billion, and generating royalties of over $0.6 billion that were all distributed to the applicable tribes and individual allotment owners. Under applicable laws, royalties are owed on all production removed or sold from Federal and Indian oil and gas leases.

[1] Each of the statutes cited above expressly authorizes the Secretary of the Interior to promulgate necessary and appropriate rules and regulations governing those leases. *See e.g.,* 30 U.S.C. 189; 30 U.S.C. 359; 30 U.S.C. 1751; 25 U.S.C. 396d; 25 U.S.C. 396; 25 U.S.C. 2107; and 43 U.S.C 1740. The Secretary has delegated this authority to the BLM. Specifically, under Secretarial Order Number 3087, dated December 3, 1982, as amended on February 7, 1983 (48 FR 8983), and the Departmental Manual (235 DM 1.1), the Secretary has delegated regulatory authority over onshore oil and gas development on Federal and Indian (except Osage Tribe) lands to the BLM. For Indian leases, the delegation of authority to the BLM is reflected in 25 CFR parts 211, 212, 213, 225, and 227. In addition, as authorized by 43 U.S.C. 1731(a), the Secretary has delegated to the BLM regulatory responsibility for oil and gas operations in Indian lands. 235 DM 1.1.K.

[2] This figure includes 168 million barrels of regularly classified oil, plus additional sales of condensate, sweet and sour crude, black wax crude, other liquid hydrocarbons, inlet scrubber and drip or scrubber condensate, and oil losses, all of which are considered to be part of oil sales for accounting purposes.

[3] This figure includes all processed and unprocessed volumes recovered on-lease, nitrogen, fuel gas, coal bed methane, and any volumes of gas lost due to venting or flaring.

The basis for those royalty payments is the measured production from those leases.

As explained in the preamble for the proposed rule, given the magnitude of oil production on Federal and Indian lands, and the BLM's statutory and management obligations, it is critically important that the BLM ensure that operators accurately measure, properly report, and account for that production. However, the BLM's rules governing how that oil is measured and accounted for are more than 25 years old and need to be updated and strengthened. Federal laws, technology, and industry standards have all changed significantly in that time. The final rule addresses the outdated nature of existing requirements and helps achieve the BLM's objective of ensuring accurate measurement by updating and replacing Order 4's requirements with regulations codified in the CFR, at a new 43 CFR subpart 3174. These new regulations reflect changes in oil measurement practices and technology since Order 4 was first promulgated in 1989.[4]

These updated requirements are the result of the BLM's evaluation of its existing requirements, based on its experience in the field, and based on the conclusion of multiple reports and evaluations of the BLM's oil and gas program—one by the Subcommittee, issued in 2007; one by the OIG, issued in 2009; and two reports prepared by the GAO, issued in 2010 and 2015. Each of these is described further below.

In 2007, the Secretary appointed an independent panel—the Subcommittee—to review the Department's procedures and processes related to the management of mineral revenues and to provide advice to the Department based on that review.[5] In a report dated December 17, 2007, the Subcommittee determined that the BLM's production accountability methods are ''unconsolidated, outdated, and sometimes insufficient.'' The report observed that:

- BLM policy and guidance have not been consolidated into a single document or publication, resulting in the BLM's 31 oil and gas field offices using varying policies and guidance (see page 31);
- Some BLM policy and guidance are outdated and some policy memoranda have expired (ibid.); and
- Some BLM State Offices have issued their own ''Notices to Lessees and Operators'' (NTLs) for oil and gas operations. While such NTLs may have a positive effect on local oil and gas field operations, they nevertheless lack a national perspective and may introduce inconsistencies among the States (ibid.).

The Subcommittee specifically recommended that the BLM evaluate Order 4 to determine whether it includes sufficient guidance for ensuring that accurate royalties are paid on Federal oil production. As explained in the preamble to the proposed rule, the Interior Department formed a Fluid Minerals Team, comprising Departmental oil and gas experts. The team determined that Order 4 should be updated in light of changes in technology, the BLM, and industry practices.

As noted, in addition to the Subcommittee report, findings and recommendation addressing similar issues have been issued by the GAO (Report to Congressional Requesters, *Oil and Gas Management, Interior's Oil and Gas Production Verification Efforts Do Not Provide Reasonable Assurance of Accurate Measurement of Production Volumes,* GAO–10–313 (GAO 2010 Report), and Report to Congressional Requesters, *Oil and Gas Resources, Interior's Production Verification Efforts: Data Have Improved but Further Actions Needed,* GAO 15–39 (GAO 2015 Report)) and the OIG (*Bureau of Land Management's Oil and Gas Inspection and Enforcement Program,* CR–EV–0001–2009 (OIG Report)).

In its 2010 report, the GAO found that the Department's measurement regulations and policies do not provide reasonable assurances that oil and gas are accurately measured because, among other things, the Department's policies for tracking where and how oil and gas are measured are not consistent and effective (GAO 2010 Report, p. 20). The report also found that the BLM's regulations do not reflect current industry-adopted measurement technologies and standards designed to improve oil and gas measurement (ibid.). The GAO recommended that Interior provide Department-wide guidance on measurement technologies not addressed in current regulations and approve variances for measurement technologies in instances when the technologies are not addressed in current regulations or Department-wide guidance (see ibid., p. 80). The OIG report made a similar recommendation that the BLM, ''Ensure that oil and gas regulations are current by updating and issuing onshore orders. . . .'' (see p. 11). In its 2015 report, the GAO reiterated that ''Interior's measurement regulations do not reflect current measurement technologies and standards,'' and that this ''hampers the agency's ability to have reasonable assurance that oil and gas production is being measured accurately and verified . . .'' (GAO 2015 Report, p. 16). Among its recommendations were that the Secretary direct the BLM to ''meet its established time frame for issuing final regulations for oil measurement'' (ibid., p. 32). The OIG made similar recommendations based on the Subcommittee's report observing that the BLM should, ''(e)nsure that oil . . . regulations are current by updating and issuing onshore orders . . .'' (OIG Report, p. 11).

The GAO's recommendations related to the adequacy of the BLM's oil measurement rules are also significant because they form one of the bases for the GAO's inclusion of the BLM's oil and gas program on the GAO's High Risk List in 2011 (Report to Congressional Committees, *High Risk Series, An Update,* GAO–11–278). Specifically, the GAO concluded in 2011 ''that Interior's verification of the volume of oil . . . produced from Federal leases—on which royalties are due the Federal government—does not provide reasonable assurance that operators are accurately measuring and reporting these volumes'' (GAO–11–278, p. 15). Because the GAO's recommendations have not yet been fully implemented, the onshore oil and gas program has remained on the High Risk List in subsequent updates in 2013 (Report to Congressional Committees, *High Risk Series, An Update,* GAO–13–283) and 2015 (Report to Congressional Committees, *High Risk Series, An Update,* GAO–15–290).

Up-to-date measurement requirements are critically important because they help ensure that oil and gas produced from Federal and Indian leases are properly accounted for, thus ensuring that operators pay the proper royalties due.

As explained in more detail below, the final rule makes a number of changes that modernize and strengthen the existing requirements in Order 4. In general, this final rule will give industry more choices and flexibility for measuring oil produced from Federal and Indian leases and will also make it easier for operators in the future to adopt new technologies and processes as the industry continues to advance.

[4] Order 4, which was published in the **Federal Register** on February 24, 1989 (54 FR 8056), has been in effect since August 23, 1989.

[5] The Subcommittee was commissioned to report to the RPC, which was chartered under the Federal Advisory Committee Act to provide advice to the Secretary and other Departmental officials responsible for managing mineral leasing activities and to provide a forum for the public to voice concerns about mineral leasing activities.

In addition to updating requirements with respect to existing technologies, the final rule also specifically recognizes advances in measurement technology by affirmatively allowing operators to use a CMS [6] or an ATG/hybrid tank measurement system without first receiving a variance from the BLM, as is currently required.[7] In response to GAO and RPC concerns that BLM field offices put out various policies and guidance, the final rule establishes nationwide requirements and standards for this measurement equipment, including a nationwide process for reviewing and approving new technology as it is developed. This change is significant because CMSs have proven to be reliable and accurate in field and laboratory testing and, when the time comes to replace their older systems, more and more operators are opting to use CMSs.

Similarly, operators in newer well fields have been using ATG systems for internal inventory purposes for over 10 years and only recently have they started using them to measure oil for sales and royalty-determination purposes. The BLM reviewed proprietary ATG test data that operators submitted to the BLM—both as public comment on the proposed rule and in support of variance requests to have ATG systems replace manual tank gauging. Based on that review, the BLM believes that ATG/hybrid systems can meet or exceed this rule's tank-gauging standards and as a result they should be expressly allowed. Affirmatively allowing ATG and hybrid systems will also increase worker safety because eliminating the need for workers to climb on top of tanks, open hatches, and manually measure or sample oil reduces their exposure to the fumes coming out of the tanks.[8] The final rule's incorporation of ATG/hybrid systems as a permissible measurement method gives operators an additional tool to address growing safety concerns.[9]

In recognition that new measurement technologies and processes, like CMSs and ATG systems, will continue to be developed and evolve, the final rule puts in place a process and criteria that will allow for a new Production Measurement Team (PMT) to review, and for the BLM to approve for use nationwide, new measurement technologies that are demonstrated to be reliable and accurate.[10] Under this new system, operators would have to prove to the BLM that new technologies meet or exceed this rule's new uncertainty performance standards, which for the first time give the BLM a set of objective criteria that can be applied to evaluate and approve any new meters, electronic components, computers, software, and procedures not specifically addressed in these regulations. Unlike the current variance system where operators must make such a showing each and every time they wish to deploy a new technology, under the PMT approach, once a technology has been approved by the BLM based on the PMT's review, that technology can be employed at additional facilities or by additional operators without a subsequent BLM approval, so long as those facilities and operators follow all conditions of approval (COAs) established by the PMT.

Recognizing the newness of the PMT process, the final rule includes a 2-year phase-in for that system. Over the next 2 years, the BLM will develop and post on its Web site an uncertainty calculator that will help the BLM and industry determine if a particular measurement system or a new device meets the rule's uncertainty requirements. As an operator designs a new system, the operator can plug its components into the calculator and know before installing the system whether that system meets the requirements, and could be approved by the PMT. Once the BLM approves a new technology for use, it will post the make, model, size, or software version on its Web site as approved for use for all operators nationwide.

With respect to the PMT, it should be noted that while the final rule provides that the PMT will review requests and make recommendations to the BLM for approval, it is the BLM's intent that such approvals will be issued by a BLM AO with authority over the oil and gas program nationally (*e.g.,* the Director, a Deputy Director, or an Assistant Director), as opposed to that authority being delegated to a local level. This is consistent with recommendations from the RPC, GAO, and OIG that decisions on variances be granted at the national level to ensure they are consistent and have the appropriate perspective, as opposed to more local levels, which can result in inconsistencies among BLM field offices.

In another important departure from Order 4, this final rule avoids, where possible, cookbook-style lists of requirements for operators to follow when determining oil quantity and quality. Instead, in many instances, the rule simply requires operators to follow the applicable industry standards, which were developed through a consensus process by professional industry groups, with input from Federal oil and gas experts. In each instance, the BLM carefully reviewed the applicable standards and determined they are technically sufficient to meet the BLM's production verification needs and are structured in such a way that they can be enforced by BLM personnel in the field. The incorporation of industry standards into the final rule gives operators more flexibility to comply with the requirements of these regulations. For example, Order 4 had one specific way for operators to measure oil temperature—by inserting a thermometer in the approximate vertical center of the fluid column, not less than 12 inches from the tank shell for 5 minutes. The final rule still allows operators to measure oil temperature using this method, but they can now also follow American Petroleum Institute (API) Chapter 7 standards, which provide for operators to use built-in tank thermometers or to take measurements from the flow lines that lead to the haulers' trucks.

The rule also adopts a number of smaller changes which, taken together, will increase measurement accuracy, increase verifiability, and reduce waste. First, it would prohibit the use of automatic temperature/gravity compensators on lease automatic custody transfer (LACT) systems, which are required equipment under Order 4. These compensators automatically

[6] A CMS is a metering system that uses a Coriolis flow meter in conjunction with a tertiary device, pressure transducer, and temperature transducer in order to derive and report gross standard oil volume. A Coriolis flow meter is based on the principle that fluid mass flow through a tube results in a measurable twisting or distortion and consequent oscillation of the tube. Sensors measure that oscillation and allow for a determination of various variables, including volume.

[7] As explained in the proposed rule, since this equipment was not included in Order 4, the BLM did not have uniform national performance standards for these systems, which has led BLM state and field offices, while approving variances, to specify their own. The state-by-state approach results in inconsistencies among offices with respect to the requirements imposed on operators.

[8] The Durango Herald, *New hazard with oilfield work,* March 7, 2016; *http://www.durangoherald.com/article/20160307/NEWS01/160309666/New-hazard-with-oilfield-work.*

[9] In recent months this safety issue has been highlighted by news reports of the deaths of oil workers who died after manually opening oil tank hatches and being exposed to toxic fumes.

[10] The PMT is distinct from the Interior's Gas and Oil Measurement Team (DOI GOMT), which consists of members with gas or oil measurement expertise from the BLM, the ONRR, and the Bureau of Safety and Environmental Enforcement (BSEE). BSEE handles production accountability for Federal offshore leases. The DOI GOMT is a coordinating body that enables the BLM and BSEE to consider measurement issues and track developments of common concern to both agencies. The BLM expects that the members of the BLM PMT would participate as part of the DOI GOMT.

adjust LACT totalizer readings to account for temperature effects and, in some cases, oil gravity effects on volume. However, because these automatic compensators do not maintain the raw data the BLM needs to verify that the compensators are functioning correctly or that the totalizer readings are correct, this rule requires operators to use temperature averaging devices instead, which record and average the temperatures of the fluids flowing through the LACT. This requirement ensures that the necessary audit trail is maintained. Such a system strikes the right balance because it gives operators the data they need to manually correct the volumes from the totalizer for the effects of temperature and oil gravity, while ensuring that the BLM has the raw data needed to verify the results and confirm system functionality.

Finally, the rule requires all oil storage tanks, hatches, connections, and other access points to be installed and maintained in accordance with manufacturers' specifications. This requirement, in effect, requires operators to maintain the pressure-vacuum integrity that manufacturers designed and built into their equipment. This in turn will minimize hydrocarbon gas lost to the atmosphere.

II. Overview of Final Rule, Section-by-Section Analysis and Response to Comments on the Proposed Rule

A. General Overview of the Final Rule

As discussed in the background section of this preamble, the BLM's rules concerning oil measurement found in Order 4 have not kept pace with industry standards and practices, statutory requirements, or applicable measurement technology and practices. The final rule enhances the BLM's overall production accountability efforts by addressing these concerns and ensuring that the oil produced from Federal and Indian (except Osage Tribe) leases is adequately accounted for, ultimately ensuring that all royalties due are paid.

The following table provides an overview of the changes between the proposed rule and this final rule. A similar chart explaining the differences between the proposed rule and Order 4 appears in the proposed rule at 80 FR 58955–58956.

Proposed rule	Final rule	Substantive changes
43 CFR 3174.1—Definitions and Acronyms.	43 CFR 3174.1—Definitions and Acronyms.	The final rule removes definitions for "registered volume," "resistance thermal device," and "turbulent flow." It changes the definitions for "base pressure" and "Coriolis meter." It adds new definitions for "indicated volume" and "transducer."
43 CFR 3174.2—General Requirements.	43 CFR 3174.2—General Requirements.	The final rule gives operators a phase-in period of 1 to 4 years after the rule's effective date to bring existing facility measurement point (FMP) equipment into compliance. This timeframe is based on the operators' production volumes and it coincides with their schedule for applying for their FMP numbers. A new paragraph (g) in this section delays for 2 years a requirement that operators begin using approved equipment listed on the BLM website (*www.blm.gov*).
43 CFR 3174.3—Specific Measurement Performance Requirements.	43 CFR 3174.3—Incorporation by Reference.	The final rule adopts the latest versions of certain API standards and incorporates them by reference into the BLM's oil and gas regulations. It incorporates by reference many API standards that did not appear in the proposed rule and removes two industry standards developed by the American Society for Testing and Materials (ASTM).
43 CFR 3174.4—Incorporation by Reference.	43 CFR 3174.4—Specific Measurement Performance Requirements.	The final rule establishes two thresholds for overall oil measurement uncertainty levels. For FMPs measuring greater than or equal to 30,000 barrels (bbl)/month, the maximum uncertainty is ±0.50 percent. For FMPs measuring less than 30,000 bbl/month, the maximum uncertainty level is ±1.50 percent. Paragraph (d) is revised to clarify that the PMT, following the process outlined in § 3174.13, will make a determination whether proposed alternative equipment or measurement procedures meet or exceed the objectives and intent of this section.
43 CFR 3174.5 and 3174.6—Oil Measurement by Manual Tank Gauging.	43 CFR 3174.5 and 3174.6—Oil Measurement by Tank Gauging.	The final rule requires operators to submit sales tank calibration charts (tank tables) to the authorized officer (AO) within 45 days after calibrating or recalibrating. It allows operators to use ATG systems and, by replacing prescriptive language with additional industry standards, it gives operators more options for tank gauging, sampling, calibrating sales tanks, and determining temperature, oil gravity, and sediment and water (S&W) content. The final rule specifies manual gauging accuracy to the nearest ¼ inch for tanks of 1,000 bbl or less and gauging accuracy to the nearest ⅛ inch for tanks greater than 1,000 bbl. All oil storage tanks must be clearly identified with an operator-generated unique number.

Proposed rule	Final rule	Substantive changes
43 CFR 3174.7 and 3174.8—LACT Systems.	43 CFR 3174.7 and 3174.8—LACT Systems.	The final rule requires operators to notify the AO of any LACT system failures or equipment malfunctions, or other failures that could adversely affect oil measurement within 72 hours upon discovery. The requirement in proposed § 3174.7(b) that operators generate an additional run ticket before proving a LACT system has been modified. A related change in § 3174.12(b)(1) makes it clear that LACT systems that use flow computers are exempt from the requirement that operators close a run ticket before proving a LACT system. The table in proposed § 3174.7(c) entitled, ''Standards to Measure Oil by a LACT System,'' has been removed and in its place the final rule requires operators to complete measurement tickets as required under § 3174.12(b). Industry standards have been added to replace prescriptive language in the proposed rule. This gives operators more choices for collecting, mixing, and analyzing samples. The final rule clarifies that LACT systems may have either a Coriolis meter or a positive displacement (PD) meter.
43 CFR 3174.9—Coriolis Measurement System—General Requirements and Components.	43 CFR 3174.9—Coriolis Measurement System—General Requirements and Components.	The final rule is revised to clarify that operators can use CMSs as a standalone unit, independent of a LACT system. The table in paragraph (d) entitled, ''Standards Applicable to CMS Use,'' has been removed and in its place the final rule requires operators to complete measurement tickets, as required under § 3174.12(b). Prescriptive language in proposed paragraph (e) that dictated which CMS components should be used during set up and installation of a CMS, for the most part, has been removed and replaced with industry standards, which give operators more flexibility. The requirement for a back pressure valve has been removed and operators may use any means to apply sufficient back pressure to ensure single-phase flow so long as it meets industry standard API 5.6. Industry standards have been added to give operators more options for automatic sampling and for mixing and handling samples. A new paragraph (g) has been added that requires operators to follow API 12.2.1 and API 12.2.2 for calculating net standard volume. A similar, more prescriptive requirement for calculating net standard volume appeared in proposed § 3174.10(g), which has been removed from the final rule.
43 CFR 3174.10—Coriolis Measurement System—Operating Requirements.	43 CFR 3174.10—Coriolis meter for LACT and CMS Measurement Applications.	Requirement for straight piping upstream and downstream of a meter has been removed from the final rule. The requirement for verifying the meter zero value is revised to be less prescriptive and instead requires operators to follow manufacturers' specifications and procedures. The requirement that operators keep the log containing the meter factor, zero verification, and zero adjustments on site has been changed to require them to make it available to the AO upon request.
43 CFR 3174.11—Meter-Proving Requirements.	43 CFR 3174.11—Meter-Proving Requirements.	The final rule requires proving every 3 months (quarterly) after last proving, or after every 75,000 bbl of volume flows through the meter, whichever comes first, but no more frequently than monthly. The rule includes verification requirements for pressure, temperature, and density measurement devices with each proving. The table in proposed paragraph (b) entitled, ''Minimum Standards for Proving FMP Meters,'' has been removed because it is not needed. The proposed requirement for master meter repeatability of 0.0002 (0.02 percent) has been changed to 0.0005 (0.05 percent). The frequency for proving master meters is no less than once every 12 months. The final rule replaces prescriptive language that dictated the sizes and proving frequencies of displacement provers with requirements that operators follow industry standards. Paragraph (c)(4) adds the requirement that operators follow industry standards when calculating the average meter factor. Paragraph (c)(6) contains new language on how to utilize multiple meter factors. Meter-proving reports may be submitted to the AO in either hard-copy or electronic format.
43 CFR 3174.12—Measurement Tickets.	43 CFR 3174.12—Measurement Tickets.	The final rule requires that oil measurement tickets for LACT systems and CMS be closed at the end of each month and before proving unless utilizing flow computers. The rule allows the use of electronic measurement tickets. The final rule no longer requires the operator's representative to certify that the measurement on a completed run ticket is correct. The final rule has also removed the requirement that operators must notify the AO within 7 days if they disagree with a tank gauger's measurement.
43 CFR 3174.13—Oil Measurement by Other Methods.	43 CFR 3174.13—Oil Measurement by Other Methods.	None.

Proposed rule	Final rule	Substantive changes
43 CFR 3174.14—Determination of Oil Volumes by Methods Other Than Measurement.	43 CFR 3174.14—Determination of Oil Volumes by Methods Other Than Measurement.	None.
43 CFR 3174.15—Immediate Assessments.	43 CFR 3174.15—Immediate Assessments.	The final rule removes one of the six violations listed in the proposed rule: Failure to notify the AO within 7 days of any changes to any CMS internal calibration factors (proposed violation #4). Of the five remaining violations listed, the final rule changes the timeframe from "within 24 hours" to "within 72 hours" that operators must notify the AO of any LACT system failure or equipment malfunction resulting in use of an unapproved alternative method of measurement (violation #2 in the final rule). The final rule also removes the word "variance" from the violation of failure to obtain a written approval before using any oil measurement method other than tank gauging, LACT system, or CMS at an FMP (violation #5 in the final rule).

B. Section-by-Section Analysis of the Final Rule and Response to Comments on Specific Provisions of the Proposed Rule

This final rule is codified primarily in a new 43 CFR subpart 3174 within a new part 3170. In addition to this rule, the BLM has also prepared separate rules to update and replace Onshore Oil and Gas Order Number 3 (Order 3) (site security), which will be codified at a new 43 CFR subpart 3173; and Onshore Oil and Gas Order Number 5 (Order 5) (gas measurement), which will be codified at a new 43 CFR subpart 3175. The rules to replace Orders 3 and 5 are being published concurrently with this rule. In addition to establishing a new 43 CFR subpart 3173, the rule to replace Order 3 establishes 43 CFR part 3170 and subpart 3170. Subpart 3170 contains definitions of certain terms common to more than one of these rules, as well as other provisions common to all of the rules, such as provisions prohibiting bypass of and tampering with meters; procedures for obtaining variances from the requirements of a particular rule; requirements for recordkeeping, records retention, and submission; and administrative appeal procedures. All of the definitions and substantive provisions of subpart 3170 also apply to this new subpart 3174.

Certain provisions of this final rule will result in amendments to related provisions in the onshore oil and gas operations rules in 43 CFR part 3160. The amendments to those provisions are also discussed below.

Subpart 3174 and Related Provisions

Section 3174.1 Definitions and Acronyms

Section 3174.1 defines terms and acronyms used in subpart 3174. Defining these terms and acronyms is necessary to ensure consistent interpretation and implementation of this rule. The BLM received a number of comments on this section. Except as noted in this section, the terms and acronyms in § 3174.1 did not change between the draft and final rule. A summary of the definitions and acronyms that were not changed in the final rule may be found in the proposed rule.

Several commenters recommended that base pressure should be defined as 14.696 pounds per square inch, absolute (psia), as opposed to defining it, as in the proposed rule, as the atmospheric pressure or the vapor pressure of the liquid at 60 °F, whichever is higher. Subsequent research has shown that base pressure should be defined as a fixed amount and therefore the BLM agrees with these comments. As a result, the definition of base pressure has been changed to 14.696 psia in the final rule.

Several commenters had concerns about the definition of Coriolis meter and Coriolis metering system (CMS). They suggested we replace the word "measures" in the definition of Coriolis meter with the word "infers." The BLM agrees with this comment because the Coriolis meter does not actually measure volume directly as a positive displacement (PD) meter does, by isolating the flowing liquid into segments of known volume, but instead analyzes the interaction between the flowing fluid and the oscillation of the tubes. As a result, the definition of Coriolis has been changed to say that a Coriolis meter infers a mass flow rate. Another commenter said the definition of CMS should be changed to say the CMS reports "net standard oil volume" instead of "net oil volume," while another commenter noted that the Coriolis meter displays "gross," not "net" standard volumes. The BLM agrees with these suggestions because the Coriolis meter is capable of correcting to gross standard volume, but not capable of deducting the S&W content to derive net standard volumes. The definition has been changed in the final rule to "gross standard volume" as a result of this comment.

Another commenter requested that we include a definition in the rule for "vapor tight." The proposed rule at § 3174.5(b)(3) required all oil storage tanks, hatches, connections, and other access points to be vapor tight. The BLM agrees that the term "vapor tight" should be defined and has defined the term to mean capable of holding pressure differential only slightly higher than that of installed pressure-relieving or vapor recovery devices.

A few commenters suggested that all of the definitions in the rule should come from the API standards, rather than be the BLM's own customized definitions. After comparing the API definitions against the BLM's definitions in the rule, the BLM does not agree with this suggestion. Not all API definitions fit the terms used in the rule. For example, one commenter said the BLM should use the API definition for LACT systems, which defines turbine meters as an example of a meter that can be part of a LACT system. The BLM disagrees with this comment because the rule does not allow turbine meters to be used at a FMP. The BLM has used many API definitions in the rule, but not all of them are suitable for this rule, therefore, this rule was not changed as a result of these comments.

Three commenters suggested that we include definitions for the acronyms "AO," authorized officer; "PA," participating area; and "CA," communitization agreement. The definitions for the acronyms AO, PA, and CA are included in the definitions section of 43 CFR subpart 3170, which is in a related rulemaking previously discussed. As a result, no change was made to this rule as a result of these comments.

One commenter suggested that we not use the term "registered volume," but rather the term "indicated volume." The

BLM agrees that the term ''indicated volume'' is a more appropriate term for the definition and aligns with common industry language, and as a result has changed the definition in the rule to reflect the definition for indicated volume.

One commenter said the term ''resistance thermal device'' is not a common industry term and suggested we change it to ''resistance thermal detector.'' As a result of this comment and a review of comments and changes to other sections, the term and definition for ''resistance thermal device'' has been removed and replaced by the term ''transducer.'' Transducer has been defined to be 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. This defines a broader spectrum of devices and can include a resistance thermal detector. This use of the term ''transducer'' aligns with common industry practice and better suits the BLM's objective of ensuring that there is sufficient flexibility built into the rule.

One commenter suggested that we change our definition of ''turbulent flow'' to include a reference to the common measure for determining the flow, which is by Reynolds number. Since the final rule does not contain the turbulent-flow requirements that appeared in the proposed rule at § 3174.8(b)(1), the BLM has removed this term from the definitions section.

Based on changes to other sections resulting in new terms being introduced, a definition for ''dynamic meter factor'' has been included as meaning 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. In the revised non-prescriptive structure of the final rule, the term ''opaque oil'' is no longer used, as such the definition has been removed.

Section 3174.2 General Requirements

Paragraphs (a) through (d) of § 3174.2 refer the reader to other sections in this rule and to 43 CFR subpart 3173, which is addressed in the rulemaking to replace Order 3. That rulemaking contains the requirements for oil storage tanks, on-lease oil measurement, commingling, and FMP numbers, respectively. All comments received on these paragraphs are addressed in the corresponding section discussions later in this preamble and in the preamble for 43 CFR subpart 3173.

Section 3174.2(e) specifies that all equipment used to measure the volume of oil for royalty purposes at an FMP installed after the effective date of this subpart must comply with the requirements of this subpart. The BLM received no comments on this requirement.

Section 3174.2(f) requires that measuring procedures and equipment used to measure oil for royalty purposes that are in use on the effective date of this rule, 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 the effective date of this rule, must continue to comply with the requirements of Onshore Oil and Gas Order No. 4, Measurement of oil, 54 FR 8086 (Feb 24, 1989), and any COAs and written orders applicable to that equipment.

The proposed rule would have required operators to bring existing equipment used at FMPs into compliance within 180 days after the effective date of the final rule. Many commenters said 180 days is not enough time to plan for and bring existing equipment into compliance. The BLM agrees, and in response, this final rule provides a phase-in period of 1 to 4 years after the rule's effective date to bring existing equipment into compliance.

The 1- to 4-year phase-in period is based on the time-frames established for operators to apply for their FMP numbers, which is provided for in 43 CFR 3173.12 and is addressed in a related rulemaking that is updating and replacing Order 3. This modified implementation timeframe in the final rule links compliance with the oil measurement requirement to an operator's production volumes, with lower-volume producers having more time to comply. Under this new approach, the highest 25 percent of the producing leases, CAs, or unit PAs are required to be in compliance the earliest—within 12 months of the effective date of this rule. All remaining leases, CAs, or unit PAs, based on volume thresholds, are staged out over the following 3 years.

Commenters' greatest concern with the 180-day deadline was that it was not enough time to generate new oil-storage-tank calibration tables that would have allowed them to measure volumes in ⅛-inch increments, as required in § 3174.6 of the proposed rule.[11] That is no longer a concern, however, because the final rule does not require that volumes be measured in ⅛-inch increments.

In the proposed rule, the BLM proposed switching to the ⅛-inch gauging accuracy for all tanks in order to meet one objective of the rule—to bring the oil measurement regulations up to current industry standards. However, API has two contradictory standards for manual gauging measurement accuracy on oil storage tanks—API 3.1A calls for ⅛-inch gauging accuracy for all tanks, while API 18.1 calls for a ¼-inch gauging accuracy for tanks of 1,000 bbl or less. Based on this change in industry standards and its own experience, the BLM assumed that new calibration tables could be generated from existing tank strapping measurements. Commenters disagreed, saying operators would have to hire engineering companies to reanalyze some 40,000 sales tanks across the nation. They said numerous tanks would have to be physically re-measured, or re-strapped. Some commenters said that, due to budgeting, equipment, and weather constraints, it could take them a year to re-strap their tanks. Others said it could take months to do the job.

As discussed later in § 3174.6, the BLM has decided to retain the ¼-inch gauging accuracy requirement for oil tanks with a capacity of 1,000 bbl or less, which is the current requirement, eliminating the need for operators to re-strap their tanks. To implement these standards, the BLM plans to develop a liquids uncertainty calculator that will allow its inspectors to enforce oil tank measurement uncertainty requirements for operators who elect to use automatic and hybrid tank gauging systems. It will take the BLM about 2 years to develop the uncertainty calculator and verify that automated equipment meets the uncertainty standards. During this time, operators who use automatic and hybrid tank gauging systems will still have to meet the measurement performance requirements.

Some commenters argued that existing equipment used at FMPs should not have to meet any deadline for coming into compliance with this rule's requirement and should instead be exempted from complying entirely (that is, grandfathered).

For example, one commenter said the BLM should grandfather all existing

[11] Order 4 requires ¼-inch gauging accuracy for tanks with a capacity of 1,000 bbl or less and requires strapping tables at ¼-inch increments. For tanks with a capacity greater than 1,000 bbl, Order 4 requires a ⅛-inch gauging accuracy and strapping tables at ⅛-inch increments.

equipment, but require all new installations or installations that undergo repairs costing more than 50 percent of the cost of new equipment to meet the new standards. The BLM does not agree with this proposed change for several reasons. The rule's only equipment retrofit requirement is that all automatic temperature/gravity compensators be replaced with temperature averagers. Temperature averagers are relatively inexpensive, costing around $6,500 per device, and automatic temperature/gravity compensators are not used on very many LACT systems. The BLM estimates that over 80 percent of all LACTs on Federal and Indian leases already have temperature averagers installed. A second issue the BLM has with this proposed change is that it would require the BLM to monitor all maintenance activity and estimate costs of repairs on ''grandfathered'' equipment. Finally, the commenter did not explain or provide justification for how this proposed change would be preferable to the proposed rule.

Another commenter said, as an alternative to grandfathering, equipment serving low-volume and marginal FMPs should be exempted from the requirements. The BLM does not see a need for this exemption because low-volume or marginal wells will, in most cases, be measured by manual tank gauging. Since the tank-gauging requirements in this final rule have not changed relative to the requirements in Order 4, this change was unnecessary.

Another commenter disagreed with the proposed rule's prohibition of automatic temperature/gravity compensators. These compensators should be grandfathered, the commenter said, as long as an audit trail exists whereby the raw data is available and the final results from the compensators can be recreated from this data. The commenter further stated that systems that cannot provide such data should be grandfathered in the final rule. The BLM disagrees. The fact remains that automatic compensator systems alter the raw data before any audit trail is created. They automatically change a meter's totalizer readings, erasing the raw data that the BLM and the operator need to verify that the compensators are functioning correctly and that the totalizer reading is correct.

Another commenter said that if existing equipment is not grandfathered, operators may need to install new LACT units in order to comply, which in turn would require operators to re-pipe their wells. According to this commenter, this would result in undue surface disturbance, excessive expenses, strain on the labor force, and wells that are currently in secondary recovery or that do not produce large amounts of oil being plugged prematurely, leaving behind undeveloped and valuable resources. The BLM disagrees with this interpretation of the rule's requirements. The only equipment that would have to be replaced at an FMP under both the proposed and final rules is the automatic temperature/gravity compensator, which is only one component of a PD meter of a LACT unit. Operators must replace these devices with temperature averagers, which allow operators to collect and retain the raw data the BLM needs to verify results and confirm and preserve system functionality. Based on the BLM's experience, this replacement can occur without replacing the entire LACT system. Additionally, as explained elsewhere in this preamble, most existing LACT systems do not use automatic temperature/gravity compensators.

One commenter said the midstream sector (the pipeline companies and processing plants at or downstream of the meters) would suffer if the rule does not grandfather existing equipment. The commenter did not explain or specify any negative impacts on the midstream sector from the requirement that operators replace automatic temperature/gravity compensators on LACTs. The BLM is not aware of any negative impacts this would have on the midstream sector and the commenter did not provide any information on how the midstream sector will suffer from accurate, verifiable measurement on a lease, PA, or CA. As a result, the BLM does not agree with the commenter and no change has been made to the rule based on this comment.

Several commenters said properly operating equipment should be grandfathered, and, if it must be replaced, operators should be allowed to negotiate installation timeframes with local BLM field offices. The BLM believes that this recommendation would perpetuate the problem of program requirements being inconsistently applied from state to state or field office to field office and therefore did not change the rule as a result of these comments. One of the primary goals of this final rule is to provide some nationwide consistency as to the application of these requirements.

Another commenter said that existing facilities and equipment should be grandfathered because operators could not afford an ''investment of this magnitude'' to retrofit equipment to meet the new standards. The commenter did not provide any details regarding what is meant by an ''investment of this magnitude.'' The BLM disagrees with the implication that replacing automatic temperature/gravity compensators on a LACT is a significant investment. The cost to replace automatic temperature/gravity compensators on LACT systems with temperature averagers is relatively minor—approximately $6,500 per system. No change resulted from this comment.

The BLM does not believe that existing equipment should be grandfathered. For years, the GAO and industry have voiced concerns that the BLM's measurement regulations are outdated and make it harder for the BLM to have reasonable assurance that production is being accurately measured and verified. This rule aims to address these concerns at both new and existing facilities.

Section 3174.2(g) exempts meters that are used for allocation measurement as part of commingling approvals from complying with the requirements of this subpart. Commingling approvals will be governed under new requirements in 43 CFR 3173.14, which are addressed in the rulemaking that is updating and replacing Order 3. One commenter said that meters used for allocating production from wells in approved commingling arrangements or that are in the same unit, PA, or CA should be required to meet API standards for allocation measurement. The commenter did not state a reason for this suggestion. Since the BLM does not want to impose blanket allocation measurement requirements that may not be relevant to every situation, it did not adopt this suggestion. Instead, the final rule retains the AO's discretion to include those requirements as a condition of approval on a case-by-case basis.

Section 3174.3 Incorporation by Reference (IBR)

This section previously appeared as § 3174.4 in the proposed rule, but based on edits made to the final rule, this section and proposed § 3174.3 have been switched. All comments discussed below were submitted for the previously proposed § 3174.4.

This rule incorporates a number of industry standards and recommended practices, either in whole or in part, without republishing the standards in their entirety in the CFR, a practice known as IBR. These standards have been developed through a consensus process, facilitated by the API, with input from the oil and gas industry and Federal agencies with oil and gas operational oversight responsibilities. The BLM has reviewed these standards and determined that they will achieve the intent of 43 CFR 3174.4 through 3174.13 of this rule. The legal effect of IBR is that the incorporated standards become regulatory requirements. With the approval of the Director of the Federal Register, this rule incorporates the current versions of the standards listed.

Some of the standards referenced in this section have been incorporated in their entirety. For other standards, the BLM incorporates only those sections that are relevant to the rule, meet the intent of § 3174.3 of the rule, and do not need further clarification.

The incorporation of industry standards follows the requirements found in 1 CFR part 51. The industry standards in this final rule are eligible for incorporation under 1 CFR 51.7 because, among other things, they will substantially reduce the volume of material published in the **Federal Register**; the standards are published, bound, numbered, and organized; and the standards incorporated are readily available to the general public through purchase from the standards organization or through inspection at any BLM office with oil and gas administrative responsibilities (1 CFR 51.7(a)(3) and (a)(4)). The language of incorporation in § 3174.3 meets the requirements of 1 CFR 51.9. Where appropriate, the BLM has incorporated by reference an industry standard governing a particular process and then imposed requirements that add to or modify the requirements imposed by that standard (*e.g.,* the BLM sets a specific value for a variable where the industry standard proposed a range of values or options).

All of the API materials that the BLM is incorporating by reference are available for inspection at the BLM, Division of Fluid Minerals; 20 M Street SE; Washington, DC 20003; 202–912–7162; and at all BLM offices with jurisdiction over oil and gas activities. The API materials are available for inspection and purchase at the 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.*

The following describes the API standards that the BLM has incorporated by reference into this rule:

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''). This standard describes the procedures for calibrating upright cylindrical tanks used for storing oil.

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''). This standard describes measurement and calibration procedures for determining the diameters of upright welded cylindrical tanks, or vertical cylindrical tanks with a smooth surface and either floating or fixed roofs.

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''). This standard describes a calibration procedure for applications to tanks above 26 feet in diameter with cylindrical courses that are substantially vertical.

API MPMS Chapter 3, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products; Third Edition, August 2013 (''API 3.1A''). This standard describes the following: (a) The procedures for manually gauging the liquid level of petroleum and petroleum products in non-pressure fixed roof tanks; (b) Procedures for manually gauging the level of free water that may be found with the petroleum or petroleum products; (c) Methods used to verify the length of gauge tapes under field conditions and the influence of bob weights and temperature on the gauge tape length; and (d) Influences that may affect the position of gauging reference point (either the datum plate or the reference gauge point).

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''). This standard describes the level measurement of liquid hydrocarbons in stationary, above ground, atmospheric storage tanks using automatic tank gauges (ATG). This standard discusses automatic tank gauging in general, accuracy, installation, commissioning, calibration, and verification of ATG that measure either innage or ullage.

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''). This standard describes the selection, installation, commissioning, calibration, and verification of Hybrid Tank Measurement Systems. This standard also provides a method of uncertainty analysis to enable users to select the correct components and configurations to address for the intended application.

API MPMS Chapter 4—Proving Systems, Section 1, Introduction; Third Edition, February 2005; Reaffirmed June 2014 (''API 4.1''). Section 1 is a general introduction to the subject of proving meters.

API MPMS Chapter 4—Proving Systems, Section 2, Displacement Provers; Third Edition, September 2003; Reaffirmed March 2011 (''API 4.2''). This standard outlines the essential elements of meter provers that do, and also do not, accumulate a minimum of 10,000 whole meter pulses between detector switches, and provides design and installation details for the types of displacement provers that are currently in use. The provers discussed in this chapter are designed for proving measurement devices under dynamic operating conditions with single-phase liquid hydrocarbons.

API MPMS Chapter 4, Section 5, Master-Meter Provers; Fourth Edition, June 2016 (''API 4.5''). This standard covers the use of displacement and Coriolis meters as master meters. The requirements in this standard are for single-phase liquid hydrocarbons.

API MPMS Chapter 4—Proving Systems, Section 6, Pulse Interpolation; Second Edition, May 1999; Errata April 2007; Reaffirmed October 2013 (''API 4.6''). This standard describes how the double-chronometry method of pulse interpolation, including system operating requirements and equipment testing, is applied to meter proving.

API MPMS Chapter 4, Section 8, Operation of Proving Systems; Second Edition September 2013 (''API 4.8''). This standard provides information for operating meter provers on single-phase liquid hydrocarbons.

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''). This standard covers all of the procedures required to determine the field data necessary to calculate a Base Prover Volume of Displacement Provers by the Waterdraw Method of Calibration.

API MPMS Chapter 5—Metering, Section 6, Measurement of Liquid Hydrocarbons by Coriolis Meters; First Edition, October 2002; Reaffirmed November 2013 (''API 5.6''). This standard is applicable to custody-transfer applications for liquid hydrocarbons. Topics covered are API standards used in the operation of Coriolis meters, proving and verification using volume-based methods, installation, operation, and maintenance.

API MPMS Chapter 6—Metering Assemblies, Section 1, Lease Automatic Custody Transfer (LACT) Systems; Second Edition, May 1991; Reaffirmed May 2012 (''API 6.1''). This standard describes the design, installation, calibration, and operation of a LACT system.

API MPMS Chapter 7, Temperature Determination; First Edition, June 2001; Reaffirmed February 2012 (''API 7''). This standard describes the methods, equipment, and procedures for determining the temperature of petroleum and petroleum products under both static and dynamic conditions.

API MPMS Chapter 7.3, Temperature Determination—Fixed Automatic Tank Temperature Systems, Second Edition, October 2011 (''API 7.3''). This standard describes the methods, equipment, and procedures for determining the temperature of petroleum and petroleum products under static conditions using automatic methods.

API MPMS Chapter 8, Section 1, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; Fourth Edition, October 2013 (''API 8.1''). This standard covers procedures and equipment for manually obtaining samples of liquid petroleum and petroleum products from the sample point into the primary containers.

API MPMS Chapter 8, Section 2, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products; Third Edition, October 2015 (''API 8.2''). This standard describes general procedures and equipment for automatically obtaining samples of liquid petroleum, petroleum products, and crude oils from a sample point into a primary container.

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''). This standard covers the handling, mixing, and conditioning procedures required to ensure that a particular representative sample of the liquid petroleum or petroleum product is delivered from the primary sample container/receiver into the analytical test apparatus or into intermediate containers.

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''). This standard covers the determination, using a glass hydrometer in conjunction with a series of calculations, of the density, relative density, or API gravity of crude petroleum, petroleum products, or mixtures of petroleum and nonpetroleum products normally handled as liquids and having a Reid vapor pressure of 101.325 kPa (14.696 psi) or less.

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''), This standard covers the determination of the density or relative density of light hydrocarbons including liquefied petroleum gases having a Reid vapor pressure exceeding 101.325 kPa (14.696 psi).

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''). This standard covers the determination, using a glass thermohydrometer in conjunction with a series of calculations, of the density, relative density, or API gravity of crude petroleum, petroleum products, or mixtures of petroleum and nonpetroleum products normally handled as liquids and having a Reid vapor pressure of 101.325 kPa (14.696 psi) or less.

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''). This standard describes the field centrifuge method for determining both water and sediment, or sediment only, in crude oil.

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 2013 (''API 11.1''). This standard provides the algorithm and implementation procedure for the correction of temperature and pressure effects on density and volume of liquid hydrocarbons that fall within the categories of crude oil.

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''). This standard provides standardized calculation methods for the quantification of liquids and the determination of base prover volumes under defined conditions. The standard specifies the equations for computing correction factors, rules for rounding, calculational sequences, and discrimination levels to be employed in the calculations.

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''). This standard provides standardized calculation methods for the quantification of liquids and specifies the equations for computing correction factors, rules for rounding, calculation sequences, and discrimination levels to be employed in the calculations.

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''). This standard provides standardized calculation methods for the determination of meter factors under defined conditions. The criteria contained here will allow different entities using various computer languages on different computer hardware (or by manual calculations) to arrive at identical results using the same standardized input data. This document also specifies the equations for computing correction factors, including the calculation sequence, discrimination levels, and rules for rounding to be employed in the calculations.

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''). This standard provides standardized calculation methods for the quantification of liquids and the determination of base prover volumes under defined conditions. The criteria contained in this document allow different individuals, using various computer languages on different computer hardware (or manual calculations), to arrive at identical results using the same standardized input data. This standard specifies the equations for computing correction factors, rules for rounding, the sequence of the calculations, and the discrimination levels of all numbers to be used in these calculations.

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''). This standard covers the basic concepts involved in estimating errors by statistical techniques and ensuring that results are quoted in the most meaningful way. This standard also discusses the statistical procedures that should be followed in estimating a true quantity from one or more measurements and in deriving the range of uncertainty of the results.

API MPMS Chapter 13, Section 3, Measurement Uncertainty; First Edition, May 2016 (''API 13.3''). This standard establishes a methodology for developing an uncertainty analysis.

API MPMS Chapter 14, Section 3/ American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 1, Section 12, General Equations and Uncertainty Guidelines; Fourth Edition, September 2012; Errata July 2013 (''API 14.3''). This standard provides reference for engineering equations and uncertainty estimations.

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''). This standard describes the procedures, organized into a recommended sequence of steps, for manually determining the quantity and quality of crude oil being transferred under field conditions.

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''). This standard defines the minimum equipment and methods used to determine the quantity and quality of oil being loaded from a lease tank to a truck trailer without requiring direct access to a lease tank gauge hatch.

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''). This standard provides for the effective utilization of electronic liquid measurement systems for custody-transfer measurement of liquid hydrocarbons.

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''). This recommended practice is a guide on new tank installations and maintenance of existing tanks. Specific provisions of this recommended practice are identified as requirements in this final rule.

API RP 2556, Correction Gauge Tables for Incrustation; Second Edition, August 1993; Reaffirmed November 2013 (''API RP 2556''). This recommended practice provides for correcting gauge tables for incrustation applied to tank capacity tables. The tables given in this recommended practice show the percent of error of measurement caused by varying thicknesses of uniform incrustation in tanks of various sizes.

The BLM received numerous comments addressing the incorporation by reference documents. Several commenters were concerned that the BLM was not incorporating the most recent versions of API standards. The API standards are dynamic standards that are constantly being reviewed and updated. The commenters referred to standards that were updated and published either after the proposed rule published or during the BLM's final internal review process before publishing the proposed rule. The BLM generally agrees with the commenters that the latest editions of industry standards should be incorporated and has made the change here after reviewing the latest version of the standards to confirm they will satisfy the applicable requirements.

Several commenters said that some of the incorporated materials in the proposed rule were in conflict. For example, ASTM D1250–1980 version tables 5A and 6A for temperature and gravity correction factors and API 11.1 for the correction of temperature effects on density and volume provide differing correction factors that may result in different corrected oil volumes. The BLM agrees with these comments and has removed ASTM D1250–1980 tables 5A and 6A from the list of incorporated materials. The final rule now refers to API 11.1 for calculations of temperature and pressure effects on density and volume.

Several commenters expressed concern that the BLM will not be updating the incorporated industry standards as new versions are published. The BLM is aware of the need to continuously monitor the industry standards as they are revised and updated, and intends to draft guidance to ensure that the BLM's rules and the incorporated standards they reference are kept up-to-date as technology and practices change. Under the applicable IBR rules, however, the BLM cannot automatically incorporate updated versions of standards into BLM regulations. The rules require that BLM reference the specific version of any particular standard being incorporated. Recognizing that these standards are continually being updated, the BLM intends to undertake periodic rulemakings to make corresponding updates to the relevant regulations. In the interim, an operator could submit a request to the PMT for a variance to comply with a newer version of a standard in lieu of compliance with the version listed above.

Many commenters said the BLM should rewrite the rule to be less prescriptive, to primarily reference industry standards, and to include additional API standards that would expand industry options for achieving accurate measurement. They argued that a highly prescriptive rule would discourage industry from adopting new technology as it becomes available. Upon careful consideration of these comments, the BLM has decided to take a less prescriptive approach that will achieve the ultimate goal of accurate measurement, while still maintaining our requirements for an audit trail and production accountability, and that will provide reasonable versatility for operators. The rule has been modified to be less prescriptive than the proposed rule and includes more industry standards that operators may choose from to comply with the requirements of the final rule. For example, the tank gauging section at § 3174.6 has been rewritten to refer more to industry standards and less to step-by-step instructions and requirements. Proposed § 3174.6(b)(3) had a list of requirements for taking oil samples prior to the opening gauge and was geared towards manual tank gauging. Section 3174.6(b)(3) of the final rule instead requires operators to follow one of two industry standards for taking oil samples prior to the opening gauge—API 8.1 for manual sampling or API 8.2 for sampling by automatic sampling systems. This paves the way for operators to use hybrid tank measurement systems and any other new technology that may come along in the coming years. Where necessary, the rule enhances or modifies an industry standard to ensure that the BLM's audit trail and production accountability requirements relate to lease activity and are met. For example, the rule modifies the industry standard for the tolerance on the verification for ATG systems, from ±3⁄16 inch to ±1⁄4 inch, in response to field test data that showed properly calibrated equipment has difficulty meeting the ±3⁄16 inch tolerance specified in industry standards. Also industry standards call for monthly ATG systems verification. This rule instead requires that ATG systems be verified monthly or before sales, whichever is later. This change will help smaller producers that may have sales only once every 2 or 3 months.

Several commenters had the opposite view and said the BLM should not incorporate industry standards, but rather make its regulations predominantly prescriptive, explicitly stating what is allowed and required. Their reasoning for this approach was that API RPs are optional for industry to consider following, while industry must follow BLM regulations. The BLM disagrees with the commenter's description of how these rules will be applied. Under the final rule, operators are required to comply with industry standards or practices that are incorporated by reference. As discussed earlier, the BLM has decided to take a less prescriptive approach and, where possible, incorporate multiple industry standards to give operators a choice for achieving a particular measurement standard.

Several commenters said the BLM should incorporate forthcoming industry standards that have not yet been finalized into the rule. The BLM cannot incorporate a standard that an industry trade association has not yet published. An unpublished standard is subject to change. It is possible the trade association creating the standard could completely rewrite the draft standard after the BLM incorporated it into this rule, in ways that would compromise the BLM's ability to enforce audit-trail or production-accountability requirements. The BLM disagrees with these comments and has not incorporated any unpublished standards into the rule.

One commenter suggested the BLM not incorporate industry standards but rather copy industry standard language directly into the rule. Copyright restrictions prevent the BLM from taking this course of action. Also this approach makes it harder for the BLM to update these requirements in the future. The final rule was not revised as a result of this comment.

Another commenter said the BLM is statutorily prohibited from cherry-picking industry standards for inclusion in the rule—picking and choosing which standards to apply and which to ignore. The BLM disagrees with this comment. Some industry standards do not meet the rule's goals and objectives and have not been incorporated. For example, there are industry standards for turbine meters, but the BLM does not allow these meters to be used at an FMP because, in some situations, they do not meet the BLM's accuracy requirements.

Several commenters said that incorporating industry standards puts an unreasonable financial burden on industry because it forces industry to purchase the published standards from the trade groups that create them. The BLM agrees that the cost of purchasing a complete set of industry standards is not insignificant. However, the API provides the public free, read-only access to most of the standards incorporated in this final rule. In addition, all incorporated material is available for inspection at the BLM's Division of Fluid Minerals, 20 M Street SE., Washington, DC 20003, and at all BLM offices with jurisdiction over oil and gas activities. It is also available for inspection at the National Archives and Records Administration (NARA). Several commenters stated that the BLM has not made a good effort to provide these newly required standards for public review. The BLM disagrees with this comment. As stated earlier, all industry standards incorporated by reference are available for inspection at the BLM, Division of Fluid Minerals, and at all BLM offices with jurisdiction over oil and gas activities.

The commenter also said the documents are not available in the BLM's Washington Office or in any particular field office. The BLM disagrees. The documents are available for review in the BLM's Washington Office and in all local offices that have jurisdiction over oil and gas activities. It has come to the BLM's attention that some local office personnel may not be aware of how to access the incorporated standards and, as part of the implementation process for the final rule, the BLM plans to carry out a training program to ensure that field office staff can readily access the standards as needed.

Several commenters expressed concern about who is responsible for complying with the incorporated standards—operators or their contractors. The incorporated standards are regulatory requirements, and operators are responsible for ensuring that third parties that do not have a contractual relationship with the BLM comply with the incorporated industry standards. Existing BLM regulations at 43 CFR 3162.3 state that a contractor on a leasehold will be considered the agent of the operator for such operations with full responsibility for acting on behalf of the operator for purposes of complying with applicable laws, regulations, the lease terms, NTLs, Onshore Oil and Gas Orders, and other orders and instructions of the AO.

Several commenters said the industry standards as written are not enforceable by the BLM. The BLM disagrees. Many of the industry standards employ the terms ''shall'' and ''should,'' with ''shall'' denoting a minimum requirement necessary to conform to the specification, and ''should'' denoting a recommendation or that which is advised, though is not required, in order to conform to the specification. However, once the standards are incorporated into BLM regulations, operators must comply with them whether the standard uses the word ''shall'' or ''should.'' One commenter inquired whether operators will be required to follow a standard, and if any deviation from a standard is a violation. As stated previously, operators must comply with all incorporated standards and material, and any deviation without an approved variance is a violation.

Section 3174.4 Specific Measurement Performance Requirements

This section was previously published as § 3174.3. Based on edits made to the final rule, this section and previously published § 3174.4 have been switched. All discussion of comments here were submitted under the previous proposed § 3174.3.

Section 3174.4(a)(1) sets volume-based overall performance standards for measuring oil produced from Federal and Indian leases, regardless of the type of meters or measurement method used. The overall volume uncertainty performance goals apply to volumes reported on the OGOR Part B (Production Disposition), commonly referred to as an OGOR B. FMPs measuring greater than or equal to 30,000 bbl per month must achieve an overall measurement uncertainty within ±0.50 percent. FMPs measuring less than 30,000 bbl per month must achieve an overall measurement uncertainty within ±1.50 percent. Existing Order 4 has no explicit statement of performance standards. The BLM will apply the performance standards in this final rule to FMPs as part of the compliance process. The performance goals could result in operating limitations (such as a minimum flow rate through the meter); however, they could also allow flexibility for various operational functions (for example, the range of error between the meter in the field and the meter prover between successive runs during a proving). To facilitate this process, the BLM is developing an oil uncertainty calculator similar to the BLM's gas uncertainty calculator currently in use. The uncertainty calculator will be an internal tool for BLM employees to use to verify uncertainty. Once it is developed, the uncertainty calculator will be available for the public to review and use. The methods for calculating uncertainty have been clarified in the final rule to be in accordance with statistical concepts described in API 13.1, the methodologies in API 13.3, the quadrature sum (square root of the sum of the squares) method described in API 14.3.1; Subsection 12.3, and other methods approved by the AO. Uncertainty indicates the risk of measurement error. The performance standards provide specific objective criteria against which the BLM could analyze operator requests to use new metering technology, measurement systems, and procedures not specifically addressed in the rule. The two-tiered uncertainty thresholds established in § 3174.4(a)(1) set the maximum allowable volume measurement uncertainty. The BLM believes that the measurement uncertainties established are reasonable, based on equipment capabilities, industry standard practices and procedures, and BLM field experience.

As noted, for FMPs measuring greater than or equal to 30,000 bbl per month, the maximum overall volume measurement uncertainty allowed is ±0.50 percent. The BLM has established the ±0.50 percent uncertainty limit based on uncertainty calculations and public comments received on the proposed rule, discussed below. The overall uncertainty calculation includes the effects of the meter accuracy; maximum allowable meter-factor drift between meter provings; the minimum standard for repeatability during a proving; the accuracy of the pressure and temperature transducers used to determine the correction for pressure on liquids (CPL) factors, and the correction for temperature on liquids (CTL) factors; and the uncertainty of the CPL and CTL calculations. The BLM chose the volume threshold of 30,000 bbl per month for this uncertainty level after determining that at this monthly volume, a one-percentage-point decrease in the expected over- or underpayment of royalties—from ±1.5 percent to ±0.5 percent—evaluated over a 5-year time frame, equals $150,000. This $150,000 amount reflects the cost to purchase a LACT system, based on price quotes from several distributors. In other words, requiring a LACT system, in terms of increased accuracy, will generate benefits that equal or exceed the cost of the new system. In making this calculation, the BLM assumed a 5-year crude oil price average of $67.58 per bbl,[12] and a royalty rate of 12.5 percent. FMPs with production volumes less than 30,000-bbl-per-month production volume do not generate sufficient volumes that the potential royalty risk justifies installing a LACT system with an expected 5-year lifespan. As a result, the maximum proposed overall measurement uncertainty for these FMPs is ±1.5 percent. The BLM believes based on available data and its experience that a ±1.5 percent threshold is reasonable and readily achievable by manual tank gauging. Based on the BLM's analysis and review of comments received, the BLM determined that the overall uncertainty of manual tank gauging ranges from ±0.6 percent to ±2.50 percent depending on the volume of oil removed from the tank at the time of sale. A ±0.6 percent uncertainty results from potential measurement error applied to large volumes, while a ±2.50 percent uncertainty results from the same potential measurement error applied to smaller volumes removed during one load-out. The ±1.5 percent uncertainty in the final rule reflects the high average calculated uncertainty for a typical truck load-out by tank gauging, which BLM believe is representative of onshore operations more generally, and therefore is an appropriate threshold to use in this rule.

The two-tiered uncertainty performance requirements in the final rule reflect modifications from the proposed rule, based on comments received. First, one commenter noted that the proposed rule did not give guidance on how the uncertainty was to be calculated. The BLM agrees with this comment and the final rule makes it clear that the uncertainty is to be calculated using API 13.1, Statistical Concepts and Procedures; API 13.3, the uncertainty methodologies; the quadrature sum method as described in API 14.3.1, Subsection 12.3, General Equations and Uncertainty Guidelines; or other methods approved by the AO.

Another commenter agreed that it is appropriate to permit a certain amount of measurement uncertainty and to utilize a tiered approach for uncertainty based on volume. However, the commenter disagreed with the proposed rule's three-tiered uncertainty requirement: ± 0.35 percent for FMPs measuring more than 10,000 bbl per month; ± 1 percent for FMPs measuring more than 100 bbl per month and less than or equal to 10,000 bbl per month; and ± 2.5 percent for FMPs measuring less than 100 bbl per month. The commenter said the proposed ± 2.5 percent uncertainty level for FMPs measuring volumes less than 100 bbl/month is both unnecessary and counterproductive. This commenter noted that there are a large number of older, low-volume wells operating on BLM and tribal leases, and argued that the ± 2.5 percent uncertainty for those operations could cause some low-volume operators to shut in their wells, resulting in a significant cumulative loss of Federal revenue from royalties. Commenters instead recommended that the BLM eliminate the lowest-volume category of the three uncertainty levels under proposed § 3174.3(a)(1). They further recommended that all FMPs with monthly volumes averaged over the previous 12 months that are less than 10,000 bbl/month should be subject to an uncertainty level of ± 1.0 percent. The commenters also said that this gives the BLM more discretion over when a less stringent uncertainty level for low-volume operators is appropriate based on site-specific factors.

The BLM partially agrees with these comments. After reanalyzing the uncertainty data and volume thresholds, the BLM has eliminated the lowest tier of uncertainty. However, this rule uses a 30,000 bbl per month volume as the dividing volume between the two tiers, and sets the uncertainty level for the highest-producing tier at ±0.50 percent and the uncertainty level for the lowest-producing tier at ±1.5 percent, which will be high enough for most tank-gauging operations while still ensuring the rules achieve accurate measurement.

The BLM chose the 30,000 bbl per month volume as the dividing line between the two tiers, and their respective uncertainty performance standards, based on what it would cost an operator to install and operate a LACT system, relative to the risk that the operator would under- or overpay royalties if measuring by tank gauging. The calculation for this assumes: A LACT system costs $150,000 and has a 5-year expected equipment lifespan, tank gauging results in a ±1.5 percent uncertainty, the 5-year oil price averages $67.58 per bbl, and the royalty rate is 12.5 percent. The following equation shows the calculation used to arrive at the 30,000 bbl per month volume

[12] Based on the projected nominal West Texas Intermediate crude oil spot price published in the U.S. Energy Information Administration's *2016 Annual Energy Outlook Reference case scenario.*

dividing line between the two tiers of uncertainty performance requirements:

Monthly volume = $150,000/((Uncertainty × Oil price × Royalty rate) × 60 months)

One commenter suggested that the performance standards for uncertainty should not be less than ±1.0 percent. A performance standard of less than ±1.0 percent is excessively onerous, the commenter said, and does not provide a substantial benefit compared to a ±1.0 percent standard. This commenter did not justify why a ±1.0 percent uncertainty standard is reasonable or how anything less is onerous. The BLM disagrees with this comment. The root square sum method of calculating the uncertainty of a LACT system with a PD meter configured and operated under the requirements of Order 4 calculates an overall uncertainty of ±0.32 percent. The final rule makes only minor changes to the Order 4 LACT requirements, so a calculated overall uncertainty rate under this rule will be similar to the existing requirements of Order 4. A LACT system with either a PD meter or a Coriolis meter is very capable of achieving the ±0.50 percent uncertainty when constructed and operated according to the requirements of this rule and corresponding API standards; no change was made as a result of this comment.

One commenter said BLM regulations do not need to specify equipment models that are acceptable for use in custody transfer measurement when uniform uncertainty metrics are utilized. The commenter stated that if any equipment meets the established uncertainty-performance standards for a measurement system, and that uncertainty can be validated and maintained, such equipment should then be allowed to be used for oil measurement. The BLM partly agrees with this comment, which is why this final rule establishes a procedure whereby the PMT can review and approve the use of new equipment and measurement methods, so long as the new equipment and methods meet the performance uncertainty and verifiability standards of the rule. The BLM believes that once this equipment has been proven to be capable of meeting the uncertainty performance and verifiability standards of this rule, then that equipment can be approved for use.

The second part of this comment suggests that the volume uncertainty limit of ±0.35 percent in the proposed rule for high-volume producers is excessively small (strict) for measurement installations that measure in excess of 10,000 bbl/month. The commenter further stated that the BLM failed to provide any basis for the proposed allowable volume uncertainty calculations. The proposed rule did not offer any detail as to how the uncertainty limit of ±0.35 percent includes any effects of maximum allowable meter-factor drift between meter proving, the minimum standard for repeatability during proving the accuracy of pressure and temperature transducers for volumetric correction, and the uncertainty in the volume-correction factor correction. The commenter also said the BLM did not disclose the data that it utilized to determine the ±1.0 percent uncertainty limit for FMPs in the 100 to 10,000 bbl/month range.

The BLM conducted an overall uncertainty calculation for a LACT utilizing a PD meter operated and proven under the requirements of Order 4. The results of this calculation provided an overall uncertainty of ±0.32 percent, which was what the BLM used to establish the higher standard in the proposed rule. The commenter did not provide a more appropriate uncertainty calculation to justify their claim that ±0.35 percent is excessively small for installations that measure in excess of 10,000 bbl per month. As a result no specific changes were made in response to this comment; however, as noted elsewhere in this section, the BLM has modified the uncertainty thresholds for larger-volume FMPs.

In order to identify appropriate thresholds, the BLM reviewed a proprietary third-party uncertainty calculation for tank gauging using Order 4 requirements for a 400 bbl tank. The results indicate that the overall uncertainty varies depending upon the volume removed from the tank. The overall uncertainty in the calculation varied from ±0.6 percent for large volumes removed to uncertainties of ±2.50 percent for very small volumes removed. The BLM reviewed overall uncertainty calculations in order to determine reasonable uncertainty requirement in the rule.

Several commenters said the BLM should re-evaluate its proposed measurement uncertainty (±0.35 percent), claiming the methodology appears to be flawed. They further stated the proposed oil measurement rule demands a level of accuracy that would not apply to heavy oil regimes and that would increase operating costs beyond what is necessary or of value. They suggest that operators with heavy oil operations may receive unwarranted and costly penalties at a greater rate than the rest of the petroleum industry, and that heavy oil producers would be disproportionately impacted by the proposed standard. These commenters did not submit justification for their claims, and when the BLM contacted them to clarify this comment, they still failed to justify or explain how heavy oil regimes would be disproportionately impacted by the rule. No change to the rule resulted from these comments.

One commenter requested that the ±0.35 percent performance uncertainty be adjusted to ±1.0 percent for meters measuring 10,000 barrels per day. The commenter agreed with comments that the API submitted to the BLM on the proposed rule and requests that the BLM use the Order 4 proving and uncertainty performance requirements for LACT systems. The BLM has re-analyzed the uncertainty performance requirements and volume thresholds, and, based on the re-evaluation and other comments received showing a different uncertainty calculation resulting in a slightly higher uncertainty than proposed, has changed the rule's uncertainty performance standards to encompass reasonable flexibility in evaluating alternative measurement equipment and methods and adjusted the volume thresholds to match volumes where the risk to royalty would equal the expense of installing a LACT or CMS to require a more accurate measurement.

Another commenter said the overall volume uncertainty limit of ±0.35 percent for measurement installations with throughputs greater than 10,000 bbl/month is unreasonably and excessively strict, given the potential number of sources of measurement error. The error should be calculated to include the uncertainty from all sources of error in the oil volumetric calculation chain. The BLM agrees in part with the comment that a ±0.35 percent uncertainty may be somewhat strict in some applications. The ±0.35 percent has been calculated to include all sources of error in the LACT measurement calculation chain, based on other comments providing similar calculations. The BLM has chosen to use a slightly higher uncertainty level in the final rule to give some leeway when considering approvals for future measurement technology and procedures for use on Federal and Indian leases. This commenter also suggested that systems installed at FMPs that measure less than 100 bbl/month should have the option to pay royalties as if they were producing at the rate of 100 bbl/month and avoid the cost of installing measurement equipment that could make their operations economically infeasible. The BLM disagrees with the concept of paying royalties based on a fixed volume rather than royalties based on actual measurements. In addition, if the uncertainty standards would render a lease uneconomic, the operator can seek an exemption from the requirements under § 3174.4(a)(2). No change to the rule resulted from this comment.

One commenter said they were unable to verify the uncertainty levels proposed without the ''calculator'' that the BLM is developing. This commenter created its own uncertainty calculation using the following assumptions: A maximum allowable deviation for temperature of 0.25 °F and pressure of 0.25 psi. The uncertainty was calculated to be ±0.46 percent in this one instance.

The BLM appreciates receiving this comment as it provides useful input and actual calculation results to support the commenter's position. As a result of this comment and further analysis, the BLM agrees that this uncertainty calculation could reflect one possible application and has adjusted the rule's lower overall uncertainty performance requirements for the highest-producing tier to ±0.50 percent.

One commenter expressed concern that the cost of complying with this provision will increase as uncertainty standards are updated. However, there is nothing in this provision that provides for the updating of the uncertainty threshold standards.

Under § 3174.4(a)(2), only a BLM State Director, with the written concurrence of the PMT, prepared in coordination with the Deputy Director, can grant an exception to the prescribed uncertainty levels. Granting an exception requires a showing that meeting the required uncertainly levels would involve extraordinary cost or unacceptable adverse environmental effects. By having the State Directors make these decisions, with concurrence of the PMT (prepared in coordination with the Deputy Director), the BLM hopes to ensure that there is consistent application of the performance standards across the Bureau and that approvals for exceptions from the performance standards are granted in limited circumstances. In the proposed rule, the BLM had proposed to require concurrence from the Director; however, upon further review, the BLM modified the written concurrence requirement to require written concurrence from the PMT that has been prepared in coordination with the Deputy Director. The BLM feels this approach would be more appropriate given that the PMT will have the necessary technical expertise, while requiring coordination with the Deputy Director ensures such changes have the necessary national policy perspective.

The BLM received several comments on its approach to exceptions to the proposed rule's uncertainty limits. A few commenters requested that the BLM clarify and limit the criteria a BLM State Director can use to grant exceptions. The BLM does not believe additional clarification is necessary and the rule's description of potential extraordinary circumstance(s) that could result in an exception to the uncertainty levels is sufficient. The BLM cannot identify every situation or event that could warrant an exception. The intent of the rule is that an exception is not a normal occurrence, and to allow exceptions only in limited, special circumstances. No change to the rule resulted from this comment.

Similarly, another commenter urged the BLM to clarify the manner in which exceptions may be granted and to clearly define the term ''extraordinary cost.'' According to this commenter, a lack of clear guidance on these exceptions will result in unrealistic expectations from operators and inconsistent application by the BLM. Again, there could be numerous circumstances under which an exception could be warranted, and the BLM cannot accurately anticipate and address all of these in the rule. It will be up to the individual or entity applying for the exception to make the case to justify an exception. The process for granting exceptions is more likely to be consistent if decisions are left to State Directors, with written concurrence from the PMT (prepared in coordination with the Deputy Director). No change to the rule resulted from this comment.

One commenter questioned why, on the one hand, the proposed rule would have authorized BLM State Directors to grant exceptions to uncertainty standards for equipment at FMPs (with BLM Director concurrence) and on the other hand, the rule at § 3174.4(d) gives the PMT the authority to recommend and the BLM to decide whether proposed alternative equipment or measurement procedures meets or exceeds the uncertainty standards. The commenter questioned a process that will rely on the availability of the PMT and State Directors to review and evaluate requests for exceptions. The commenter said BLM technical experts are often overworked, and therefore the PMT approval process is likely to take a considerable amount of time and hinder operators' ability to effectively develop Federal oil and gas resources. The BLM agrees that its technical experts have a significant workload and face a number of competing demands. However, one reason for creating a BLM-wide PMT is to relieve field offices of having to review new technology, and to provide a consistent BLM-wide decision-making process. The BLM believes that this structure should minimize the amount of time it will take for the BLM to process requests for evaluation of new equipment, and to evaluate requests for exemptions from the uncertainty requirements. No change to the rule resulted from this comment.

Section 3174.4(b) establishes the degree of allowable bias in a measurement. Bias differs from uncertainty in that bias results in systematic measurement error, whereas uncertainty only indicates a risk of measurement error. While the BLM acknowledges that it is virtually impossible to remove all bias in measurement, the final rule requires that there be no statistically significant bias at any FMPs. When a measurement device is tested against a laboratory device or prover, there is often slight disagreement, or apparent bias, between the two. However, both the measurement device being tested and the laboratory device or prover have some inherent level of uncertainty. If the disagreement between the measurement device being tested and the laboratory device or prover is less than the uncertainty of the two devices combined, then it is not possible to distinguish apparent bias in the measurement device being tested from inherent uncertainty in the devices (sometimes referred to as ''noise'' in the data). Therefore, the BLM does not consider apparent bias that is less than the uncertainty of the two devices combined to be statistically significant for purposes of compliance with the final rule. However, if the shift in the mean value of a set of measurements away from the true value of what is being measured exceeds the ''statistically combined uncertainty'' of the devices, then the BLM requires that known shift to be corrected to as close to the actual value as possible.

The BLM received several comments concerning bias. The first commenter stated the rule does not give any guidance on how bias will be determined, or what the BLM considers to be statistically significant. In order for the bias restriction to be applied uniformly throughout the nation, the commenter asserted that the term needs to be defined in the regulation. The BLM agrees with this comment and has added a new definition for ''bias'' to 43 CFR subpart 3170, as part of the rulemaking that is updating and replacing Order 3.

Another commenter noted that the BLM presented no data or calculations in the proposed rule to verify that bias issues will not exist under field conditions where many additional variables impact the statistical calculations. The commenter claimed that the rule essentially assumes that uncertainties that can be demonstrated in laboratory conditions can also be demonstrated in field conditions, which are not practical in a production scenario. The commenter asked that the BLM delete paragraph (b) from the final rule. The BLM does not agree with this comment. If a shift in the mean value of a set of measurements away from the true value of what is being measured, exceeds the statistically combined uncertainty of the devices, occurs, then the BLM requires that known shift to be corrected to as close to actual value as possible. An example of where this shift could be discovered is during a transducer verification that results in a reading that is outside of the device's stated uncertainty. This is different from uncertainty, where a potential for measurement error exists. No change to the rule resulted from this comment.

A third commenter recommended that the BLM clarify language in the preamble that discusses statistically significant bias. As noted above, the preamble quantifies statistically significant bias as being a number that is greater than the combined uncertainties of the laboratory device, or prover, and the measured device, or the ''statistically combined uncertainty.'' The BLM recognizes that there will always be some apparent bias resulting from the uncertainty of all devices. Bias is only considered significant when it exceeds the combined uncertainties of the devices involved. The BLM believes that the final rule accurately explains bias in terms of it being outside of the ''statistically combined uncertainty'' of the devices being used. No change to the rule resulted from this comment.

Section 3174.4(c) requires that all measurement equipment be subject to independent verification by the BLM that it is performing accurately and that all inputs, factors, and equations that are used to determine quantity or quality are valid. Order 4 already requires that the BLM be able to independently verify measurement methods, as well as bias, so these are not new requirements. The verifiability requirement in this section prohibits the use of measurement equipment that does not allow for independent verification. For example, if a new meter were to be developed that did not record the raw data used to derive a volume, that meter could not be used at an FMP because without the raw data the BLM would be unable to independently verify the volume. Similarly, if a meter were to be developed that used proprietary methods that precluded the ability to recalculate volumes, its use would also be prohibited.

The BLM received several comments about the verifiability requirements of this rule. One commenter seemed to suggest that the BLM did not take into account the use of automation and other measurement systems advances, such as the use of flow computers handling calculations. The comment further stated that in order to retain the raw data that the BLM needs to manually verify equipment accuracy, operators will be required to use computers that are less efficient and that require more data storage. The BLM agrees that the rule may require operators to acquire more data storage, but does not agree with the commenter that saving raw data for future verification will result in less efficient flow computers, or that it is unnecessary. The BLM manages Federal oil resources on behalf of the American taxpayer and has an affirmative obligation to ensure that the oil produced is accurately measured and accounted for. In order to satisfy those obligations it is critically important that an audit trail exists so that the BLM can verify the production data. As a result, the BLM will continue to manually verify calculations at FMPs. No change to the rule resulted from this comment.

Another commenter suggested any verifiability does not take into account the difference between live calculations at high frequencies versus averaged and accumulated data over time. The commenter also said that independent calculations should only have to fall within a statistically insignificant window. In order for independent calculations to be applied uniformly throughout the nation, they should to be defined in the regulations, the commenter said. The BLM partly agrees with this comment that calculations should be live calculations at high frequencies or calculations averaged and accumulated over time. The Inspection and Enforcement Handbook will address possible methods for the BLM to verify calculations at an FMP. No changes to the rule were made as a result of this comment, but the BLM will include guidance in the Inspection and Enforcement Handbook regarding whether calculations should be based on live calculations or averaged over time. Under the final rule, all volume calculations at an FMP must be verifiable.

One commenter asked whether the requirement that new equipment undergo independent verification will preclude new technology. The BLM does not intend to prevent or exclude new technology. In fact, this rule, by establishing performance standards, adopting industry standards, and standing up the PMT process, has been designed explicitly to provide flexibility for the BLM to adopt new technology and practices as they are developed. No changes were made in response to this comment.

Another commenter said that paragraph (c) would require the BLM to contract with an independent laboratory to verify equipment, which could take 6 months per device and cost upwards of ''$500M'' for each device. The BLM disagrees with this comment because § 3174.4(c) merely requires operators to have FMP equipment that can produce the source records that provide the data and equations the BLM needs to independently recalculate oil production volume and quality during production audits. No changes were made in response to this comment.

Section 3174.4(d) clarifies that the operator can propose the use of alternative equipment, provided that it meets or exceeds the uncertainty requirements of this section. The PMT will make a determination under § 3174.13 of this subpart regarding whether proposed alternative equipment or measurement procedures meets or exceeds the objectives and intent of this section. See § 3174.13 for discussion of comments concerning the PMT and the PMT review process.

Section 3174.5 Oil Measurement by Tank Gauging—General Requirements

Section 3174.5(a) specifies the general requirements for oil measurement by tank gauging as a means to accurately determine the quantity and quality of oil removed from an FMP. The BLM received many comments on this section of the proposed rule. Almost all of these comments requested that the BLM consider permitting the use of ATG systems for custody transfer applications. Order 4 allows only manual tank gauging. In the proposed rule, the BLM indicated that it was considering including provisions in the final rule allowing for the use of ATG systems, and requested data regarding whether these systems can meet the BLM's performance standards for manual tank gauging with respect to uncertainty and verifiability. The BLM requested additional data regarding ATG measurement systems because it recognizes the significant safety advantages they provide.

The majority of the commenters indicated that ATG systems are much safer for workers when compared to manual tank gauging systems, especially when workers are measuring hydrocarbon fluids such as those found in the Bakken, which have higher gravity and higher vapor pressure, and thus emit higher volumes of toxic fumes. The BLM agrees that safety concerns associated with manual tank gauging can be reduced if operators have the option of using ATG systems as well as the other measurement methods addressed in this final rule. Based on data provided in response to the proposed rule—both as public comment on the proposed rule and in support of project-specific variance requests to use ATG systems on tanks—the BLM has determined that ATG systems can meet or exceed the uncertainty thresholds for tank gauging. As a result, the rule has been changed to allow for the use of ATG systems.

The BLM received one comment that recommended the BLM prohibit the practice of oil measurement by manual tank gauging because, according to the commenter, the practice is an antiquated and considerably less reliable method of measurement. The BLM disagrees that properly conducted manual tank gauging operations are antiquated or less reliable than other methods of measurement and will continue to give operators the option of using this widely accepted practice for oil measurement, which is generally used at lower-volume facilities. However, the BLM hopes for a shift towards ATG in areas where the nature of the produced oil presents a safety concern.

In the proposed rule, § 3174.5(b) required that all oil storage tanks, hatches, connections, and other access points be vapor tight and that each oil storage tank, unless connected to a vapor recovery system, must have a pressure-vacuum relief valve installed at the highest point in the vent line or connection with another tank. Pressure-vacuum relief valves would provide for normal inflow and outflow venting at an outlet pressure that is less than the thief hatch exhaust pressure and at an inlet pressure that is greater than the thief hatch vacuum setting. The intent is to minimize hydrocarbon gas lost to the atmosphere by ensuring that venting is done under controlled conditions through the pressure-vacuum relief valve primarily in response to changes in ambient temperature. The requirement that all access points be vapor tight has been expressly included in this rule in order to eliminate confusion over the intent of Order 4, which specified all the same equipment, but did not specify the manner in which it was supposed to be operated. The implied intent of Order 4 was always that the tanks be operated such that they are vapor tight.

The BLM received numerous comments on this section, the majority of which said the proposed requirements could conflict with U.S. Environmental Protection Agency (EPA) air quality regulations and the BLM's separately proposed Methane and Waste Prevention Rule (81 FR 6616). Some of the same commenters also complained about the potential costs associated with retrofitting some of the tank batteries. The BLM disagrees with these comments. The intent of the requirement is to conserve the quantity and quality of the liquid hydrocarbons in storage by controlling the storage conditions, not to create a potential conflict with the EPA's regulations for release of harmful pollutants. The BLM also disagrees with claims made by some commenters that the potential costs associated with retrofitting existing tank batteries to make them vapor-tight would be too high. Pressure vacuum vent line valves and thief hatches are already required equipment for the existing tank battery installations under Order 4. Paragraphs (b)(3) and (4) of the proposed rule have been changed and merged into a new paragraph (b)(3) in the final rule, which now requires that all oil storage tanks be vapor tight, and, unless connected to a vapor recovery or flare system, 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.

Several commenters recommended that the BLM add the requirement that oil storage tank hatches (''thief hatches'' or other access points) have pressure indicators that provide a clear and immediate visual indicator of tank pressures and potential gas/vapor release hazard should the tank need to be accessed. One of the commenters said pressure indicators on tank access hatches visually display the presence of gas/vapor pressure in a tank, allowing a trained worker to make risk-based decisions before accessing a tank, including actuating a remote venting valve, venting gas to a flare, or using appropriate respiratory protection, such as a self-contained breathing apparatus or an air-line respirator. The BLM recognizes that having such information could potentially be useful to personnel in the field; however, the BLM did not make any changes in response to this comment because the pressure indicators proposed by the commenter would have no bearing on determining measured volume, and therefore are outside the scope of this rule. It should also be noted that in general the Occupational Safety and Health Administration takes the lead on adopting and enforcing employee safety requirements.

Several commenters stated it is imperative that tanks be maintained vapor tight and that there be a monitoring or inspection program to ensure compliance. The BLM agrees and the final rule has maintained the vapor tight integrity requirement for oil storage tanks. The BLM's inspection and enforcement program will continue to ensure compliance with this and all other oil and gas regulations. No additional changes were made to the final rule as a result of these comments.

One commenter stated that if the oil is weathered or stabilized, there is no need for hatches and other connections to be vapor tight. The commenter did not explain how weathered or stabilized oil could negate the need for hatches and other connections to be vapor tight. The BLM disagrees that stabilized product does not require a vapor-tight storage condition. The vapor tight integrity is an implied requirement of the current Order 4 and therefore will not require the operator to retrofit any existing equipment. In a unique situation where a variance could be justified, the operator could seek a variance through the appropriate BLM field office following the process outlined in § 3170.6 of this part, a related rulemaking that is replacing Order 3, with approval by the AO. No additional changes were made to the final rule. This section in the final rule is now identified as § 3174.5(b)(3).

Section 3174.5(b)(5) of the proposed rule specified that all oil storage tanks must be clearly identified and have a unique number stenciled on them, maintained in a legible condition. Order 4 did not have a similar requirement. The BLM received several comments that said this section did not adequately communicate how the numbering system would work and how numbers are assigned to the tanks. The BLM agrees that this section was not clear. As a result of these comments, the final rule has been changed to specify that all oil storage tanks must be clearly identified with an operator-generated number that is unique to the lease, unit PA, or CA stenciled on the tank and maintained in a legible condition. This section now appears as § 3174.5(b)(4) in the final rule.

Section 3174.5(b)(6) of the proposed rule required each oil storage tank associated with an approved FMP by tank gauging to be set and maintained level. Several commenters said this requirement is unwarranted and unnecessary without offering any details. The BLM disagrees, as this is not a new requirement. Order 4 has a similar requirement, and the BLM believes that not requiring a tank to be set or maintained level would be unacceptable because it could result in uncertainty in measurement. Industry standards also dictate that tanks used for gauging operations should be level. No change resulted from these comments. This section now appears as § 3174.5(b)(5) in the final rule.

Section 3174.5(b)(7) of the proposed rule specified each oil storage tank associated with an approved FMP that has a tank-gauging system must be equipped with a distinct gauging reference point, with the height of the reference point stamped on a fixed bench-mark plate or stenciled on the tank near the gauging hatch, and maintained in a legible condition. One commenter, without offering any justification, said this requirement should apply only to tanks that are manually gauged. The BLM disagrees as this gauging reference point is also needed during the verification and calibration of an ATG system, not just for tanks that are measured by manual gauging. No change was made to the final rule as a result of this comment. This section now appears as § 3174.5(b)(6) in the final rule.

Section 3174.5(c) in the proposed rule required the operator to accurately calibrate each oil storage tank associated with an approved FMP that has a tank-gauging system, under either API 2.2A or API RP 2556. Order 4 had a similar requirement. The BLM received a few comments on this section. One commenter pointed out that under the proposed rule, sales tank calibrations apparently can only be made using API MPMS Chapter 2.2A—Tank Strapping by Manual Method, when in fact other methodologies in Chapter 2 are available. The BLM agrees that industry standards provide additional methods for calibrating sales tanks. As a result of this comment, the BLM changed the final rule to incorporate industry standards API 2.2A, API 2.2B, or API 2.2C; and API RP 2556. One commenter stated the proposed rule did not clarify when or how often a sales tank calibration is required. The BLM disagrees. Section 3174.5(c)(2) clearly states when a sales tank calibration is required—if the tank is relocated, repaired, or the capacity is changed as a result of denting, damage, installation, removal of interior components or other alterations. No changes were made to the final rule as a result of this comment.

One commenter said operators should be allowed to use formulas for estimating tank volumes. The formula of 1.67 bbl/inch is a tool operators use to estimate the volume stored in the tank. When the oil is sold, the commenter said, a more accurate measurement will be taken, ensuring that the operator is properly paid for the oil being sold, which will in turn result in the correct royalty payment to the government. This rule seeks to ensure accurate oil measurement, not volume estimates. This comment is not relevant to sales tank calibration. The final rule was not changed as a result of this comment.

Section 3174.5(c)(1)(i) of the proposed rule specified the strapping table unit volume must be in barrels. The BLM received no comments and made no changes to this paragraph.

Section 3174.5(c)(1)(ii) of the proposed rule specified the incremental height measurement on all tanks must be in ⅛-inch increments. This was a change from the incremental height measurement in Order 4 of ¼-inch gauging accuracy for tanks of 1,000 bbl or less in capacity. The BLM received many comments on this section. The commenters consistently addressed the following two main points: (1) The benefits from the increase in accuracy would be minimal in comparison to the time and costs it would take to achieve the increased accuracy; and (2) The change would require operators to re-strap their tanks and generate new tank tables, and, in many cases, make major changes to their software programs, all at substantial costs. The BLM agrees that the costs of a change to ⅛-inch increments for tank gauging on tanks that are 1,000 bbl or less in capacity is unnecessary because the additional cost burdens outweigh any potential accuracy gains. As a result of these comments, the rule has been changed to say that the incremental height measurement must match the gauging increments specified in § 3174.6(b)(5)(i)(C), which requires ¼-inch increments for tanks 1,000 bbl or less in capacity, and ⅛-inch increments for tanks greater than 1,000 bbl in capacity. This is the same accuracy standard that has been in effect under Order 4. The BLM would like to note that API industry standards relative to manual tank gauging have conflicting tank-gauging increments. The BLM has chosen to retain the current Order 4 gauging increments requirement by following API 18.1 tank gauging increments for tanks that are 1,000 bbl and less and API 3.1A tank gauging increments for tanks greater than 1,000 bbl.

Section 3174.5(c)(2) requires operators to 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. Order 4 had a nearly identical requirement. The BLM received a few comments on this section, all of which said there is no definition of how large the dent or alteration would need to be to trigger this requirement. The commenters also stated that the BLM must clarify the amount of volume displacement that would require action on the part of the operator. The final point that the commenters made also suggested that the BLM should offer a range of options that operators could take in response to denting, including tank inspection, and provide them an opportunity to avoid being in violation. For example, an insulated tank may be dented on the outside but the dent would have no impact on the inside due to several inches of insulation. Upon review of these comments, the BLM has made no change to the rule for the following reasons. The volume displacement from tank denting cannot be known until the dent has been measured and the impacts analyzed. To measure the impacts, this section requires re-strapping of the tank. The BLM has chosen not to allow an operator to ''estimate'' the impact of denting on a tank used for tank gauging as there would be no enforceable requirement to properly determine the resulting volume impacts. Denting of the insulation on a tank may or may not result in denting of the sales tank. If denting is observed on the insulation of a tank, it is the operator's responsibility to verify that no internal tank denting has occurred under the insulation.

Section 3174.5(c)(3) requires operators to submit sales tank calibration charts (tank tables) to the AO within 30 days after calibration. Order 4 required them to be submitted to the AO upon request. The BLM received several comments on this section. A few commenters recommended extending the 30-day time period to 45 days to allow for more coordination time between transporter and operator. After considering these comments, the BLM agrees that transporters and operators may need more time to submit the tank tables to the BLM. As a result of these comments, the final rule now requires that tank tables must be submitted to the AO within 45 days after calibration. Tank tables may be in paper or electronic format. A couple of commenters said this requirement is another example of the BLM getting into the day-to-day operations of industry. They said there is absolutely no reason for the BLM to have these charts, argued that they serve no purpose, suggested that this requirement is excessively prescriptive, and asked the BLM to justify the need for the charts. Oil tanks are constructed to API standards and have a common, industry-wide standard strapping chart, the commenters said, and these tanks are not proven once installed. The BLM disagrees with these comments, as the tank calibration charts (tank tables) are in fact unique for each tank, and therefore there should not be a common, industry-wide standard strapping chart in use where tank gauging is the method of measurement at an FMP. The BLM has a long history of using the tank tables on a daily basis for production verification efforts, such as during production inspections and records-analysis audits. No changes were made to the final rule as a result of these comments.

The BLM has an affirmative obligation to maintain an audit trail supporting Federal and tribal oil production. A couple of commenters requested that the BLM continue to use the Order 4 requirement that operators submit their latest tank calibration charts when the AO requests them, in order to avoid confusion and give operators notice that an inspection is imminent. The BLM disagrees because the new requirement will serve as verification that the operator has had the tanks strapped as required, and enables the BLM to perform the required inspection activities. Additionally, the BLM has no obligation to provide operators notice that an inspection is imminent.

One commenter said marginal producing leases should be exempt from tank-gauging requirements. The BLM disagrees. Marginal leases are already subject to tank-gauging requirements. Under this final rule, operators on marginal-producing leases are allowed to continue using manual tank gauging, which imposes only modest economic impact on these leases.

Section 3174.6 Oil Measurement by Tank Gauging—Procedures

Section 3174.6 paragraphs (a) and (b) require operators to take the steps in the order prescribed in the following paragraphs to manually determine by tank gauging the quality and quantity of oil measured under field conditions at an FMP. The BLM received several comments on this section. The comments said the detailed tank-gauging procedures in this section do not align with the industry standard. The BLM partly agrees, in that industry standards for certain activities have several options for operators to follow for achieving the desired outcome. The proposed rule did not reflect all of those options. As a result of these comments, the final rule has been changed to reference the appropriate industry standards and remove any unnecessarily prescriptive requirements to ensure accurate measurement using tank gauging.

Section 3174.6(b)(1) contains the requirement in Order 4 and the proposed rule that the tank be isolated for at least 30 minutes to allow contents to settle before proceeding with tank gauging operations. The BLM received a couple of comments on this section. The commenters said this requirement would be costly and is unnecessary, as this activity will not increase the accuracy of measurements. The BLM disagrees. This requirement will ensure that the tank is isolated and that the crude oil layer is still, with no surface foaming. In many liquid manual sampling applications, the product to be sampled contains a heavy component (such as free water) that tends to separate from the main component. In these instances, it should be recognized that until the heavy component completely settles out, sampling will likely result in varying sample qualities. No change was made to the final rule as a result of these comments.

Section 3174.6(b)(2) contains the requirements for determining the temperature of oil contained in a sales tank that is used as an FMP. Operators must comply with paragraphs (b)(2)(i) through (iii) of this section and API 7 and API 7.3. The BLM received numerous comments on this section. Several commenters requested that the BLM eliminate the reference to mercury in paragraph (b)(2)(i). In the proposed rule, that paragraph required glass thermometers to be clean, be free of mercury separation, and have a minimum graduation of 1.0 °F. The BLM agrees that the mercury reference should be removed because the EPA has banned mercury thermometers from use. As a result of these comments, the final rule has been changed to say that glass thermometers must be ''free of fluid separation.''

The BLM received a comment concerning paragraphs (ii) through (iv), which said the reported graduation and accuracy requirements for temperature measurement devices are different based on the technology employed (minimum graduation of 1.0 °F for liquid-in-glass thermometer vs. minimum graduation of 0.1 °F for portable electronic thermometers (PET)). The commenter did not elaborate, but we assume the commenter believes PETs should be as accurate as glass thermometers. This comment is not consistent with the mandate of keeping the uncertainty in the measured quantity to within a specified value, nor is it consistent with existing industry standards (API MPMS Chapter 7). The BLM disagrees in part with this comment since the BLM used the minimum graduations from the industry standard, of 1.0 °F for glass and 0.1 °F from electronic thermometers. For consistency, and as a result of this comment, the BLM is requiring an accuracy of ±0.5 °F for both glass and electronic thermometers.

Several commenters questioned the thermometer immersion times required in the proposed rule under paragraph (b)(2)(iii), which referenced API 7, Table 6. They also asked the BLM to allow alternate methods for determining opening oil temperatures, to alleviate potential safety and economic concerns. The BLM disagrees in part as the immersion times are an industry standard, but also agrees in part to allow alternate methods under API 7. The prescriptive requirements under paragraph (b)(2)(iii) have been removed because the final rule already states that operators must comply with API 7, which includes the Table 6 requirements. Furthermore, the BLM changed the rule to give operators more flexibility by allowing them to use alternate methods for temperature determinations under API 7 and API 7.3, as well as the option of using ATG/hybrid tank measurement systems, in order to address the safety concerns identified by commenters. As a result of these comments and changes, the final rule eliminates paragraph (b)(2)(iii) of the proposed rule, resulting in the renumbering of paragraph (b)(2)(iv) in the proposed rule to paragraph (b)(2)(iii) in this final rule.

Section 3174.6(b)(3) of the proposed rule specified that sampling of oil removed from an FMP tank must yield a representative sample of the oil and its physical properties, and must comply with the procedures listed in paragraphs (i) through (iii) of this section and API 8.1. The BLM received several comments requesting that the final rule give operators other sampling options. The BLM agrees that other sampling options can still achieve the desired measurement uncertainty. As a result of these comments, the BLM removed the prescriptive requirements in paragraphs (b)(3)(i) through (iii), and added a reference to API 8.2's standards for automatic sampling procedures to the final rule.

Section 3174.6(b)(4) of the proposed rule specified that tests for oil gravity must comply with paragraphs (b)(4)(i) through (iv) of this section and API 9.3. The BLM received a couple of comments on this section. One commenter said that API Chapter 9 contains additional methods for determining gravity that can be more appropriate to use (based on the conditions of the oil at sample time). Therefore, the commenter asserted that the final rule should simply specify that any API Chapter 9 methodology is appropriate for determining gravity. The commenter said the procedure outlined in the proposed section was not consistent with API 9.3. Another commenter stated that proposed paragraph (b)(4)(i), which required the use of a thermohydrometer for API gravity (density) measurement, would limit the use of new, automated, more accurate technology such as Coriolis meters and density gauges. The commenter said allowance should be made for other methods that can meet the uncertainty requirements of the regulation. The BLM agrees that this provision of the proposed rule was too prescriptive and unnecessarily limited potential compliance options. As a result of these comments, the following changes were made to the final rule:

- This section now incorporates by reference API 9.1, API 9.2, or API 9.3 to allow additional methods to measure API gravity;
- Paragraph (b)(4)(i) is changed to include the use of a hydrometer in addition to a thermohydrometer;
- Proposed paragraph (b)(4)(ii) has been removed consistent with the BLM's determination that the provision was too prescriptive;
- Proposed paragraph (b)(4)(iii) is now paragraph (b)(4)(ii) and has been revised to require operators to allow the temperature to stabilize for at least 5 minutes; and
- Proposed paragraph (b)(4)(iv) is now paragraph (b)(4)(iii) and has been revised to require operators to read and record the observed API oil gravity to the nearest 0.1 degree, and to read and record the temperature reading to the nearest 1.0 °F.

Section 3174.6(b)(5) of the proposed rule required operators to take and record the tank opening gauge only after upper, middle, and outlet samples have been taken. It further required gauging to comply with paragraphs (b)(5)(i) through (b)(5)(v) of this section and API 3.1A. One commenter said the opening measurement should be taken with a matched (bob and tape) and currently ''certified'' gauging tape. The comment recommended that the rule specify that the tape and bob shall be certified within the last year as specified in API 3.1A. The BLM agrees with this recommendation, as it is consistent with API standards. As a result, the BLM has included API 3.1A in this paragraph and has eliminated prescriptive language that repeats API 3.1A.

Similar to the proposed rule, § 3174.6(b)(5)(i) of the final rule contains the requirements for manual gauging. But in response to commenters' requests that the BLM allow automatic and hybrid tank gauging, as discussed earlier in this preamble, this section in the final rule includes a new paragraph (b)(5)(ii), which contains the requirements for ATG. During the initial years of rule implementation, the BLM will not limit which ATG makes or models operators can use, but starting 2 years after the effective date of this rule, operators will only be permitted to use the ATG makes and models that the BLM approves for use and lists on its Web site. To ensure that ATG equipment in use at that time meet with BLM approval, the BLM encourages operators, manufacturers, or other entities (*e.g.,* trade associations) to pursue equipment approval prior to use. Paragraph (b)(5)(ii) identifies requirements for inspecting and verifying the accuracy of ATG systems and for maintaining a log of field verifications.

Section 3174.6(b)(6) of the proposed rule required operators to determine S&W content using the oil samples in the centrifuge tubes collected from the upper and outlet fluid column (see paragraph (b)(3) of this section), and determine the S&W content of the oil in the sales tanks, according to paragraphs (b)(6)(i) through (iii) of this section and API 10.4. The BLM received a few comments on this section. The commenters all addressed the fact that API 10.4 has been updated since the BLM published the proposed rule, and that the prescriptive requirements in paragraphs (b)(6)(i) through (iii) were not consistent with the revised industry standard. The BLM agrees that the API standard has been updated and that the requirements in paragraphs (b)(6)(i) through (iii) of the proposed rule are too prescriptive and inconsistent with the revised industry standard. Based on its review of the revised standard and as a result of these comments, the BLM removed the prescriptive requirements in paragraphs (b)(6)(i) through (iii). The final rule requires operators to determine S&W content by using API 10.4, which has been incorporated into the final rule by reference.

Without saying why, one commenter said the BLM should incorporate all sections of API Chapter 10 into the final rule. The BLM disagrees. Since the oil measurement at issue in this rule is inherently a ''field procedure,'' in which the S&W content is required to be determined and documented on the run ticket at the completion of the tank gauging/custody transfer procedure, the BLM determined that the only applicable section is 10.4. This comment did not result in a change to the final rule.

Section 3174.6(b)(7) requires operators, after conducting the S&W determination, to conduct the transfer operation and seal the effected valves under §§ 3173.2 and 3173.5 of this part. There were no comments to this section.

Section 3174.6(b)(8) requires operators to determine the tank closing temperature following procedures discussed in paragraph (b)(2) of this section. Any comments concerning temperature determination have been addressed earlier in the paragraph (b)(2) discussion.

Section 3174.6(b)(9) requires operators to take the closing gauge using procedures in paragraph (b)(5) of this section. Any comments concerning gauging operations have been addressed in the paragraph (b)(5) discussion.

Section 3174.6(b)(10) requires operators to end their tank-gauging operations by completing a measurement ticket in accordance with § 3174.12. The proposed rule included seven activities in paragraphs (b)(10)(i) through (vii) that dictated how operators should derive the data required for the measurement tickets. Some commenters said this list of activities was too prescriptive. In an effort to be less prescriptive, the BLM deleted paragraphs (b)(10)(i) through (vii) in the final rule and refers operators to the rule's measurement-ticket requirements.

Section 3174.7 LACT System—General Requirements

Paragraphs (a) through (c) of this section in both the proposed and final rule refer operators to other sections of this rule for construction and operation requirements for LACT systems, proving requirements, and measurement tickets. The proposed rule in paragraph (a) included a reference to API standards and in paragraph (c) a table that listed the requirements and components of a LACT system, along with references to the sections of the proposed rule containing the minimum standards for each of those components. The BLM received several comments on these paragraphs.

Several commenters said the BLM should not be so prescriptive and should instead require compliance with the appropriate API standards. In general, the BLM agrees that following published industry standards can result in the desired measurement uncertainty, and paragraph (a) of the final rule now requires LACTs to meet the standards prescribed in the applicable API sections. Paragraph (b) of the final rule requires LACTs to be proven as prescribed in § 3174.11 of this subpart. The proposed table of ''Standards to measure oil by a LACT system'' from paragraph (c) has been removed. Although it was a handy reference that directed readers to requirements that were listed in other sections of the proposed rule, the table was redundant and unnecessary. Paragraph (c) in the final rule now refers to the requirement for completing measurement tickets under § 3174.12(b).

Several commenters were uncertain about whether the LACT requirements only applied to new facilities, with existing facilities grandfathered. Most of the commenters also suggested that bringing existing facilities into compliance within the 180-day implementation timeframe was either too expensive, impossible, or both. In response to these comments, and as discussed previously in this preamble, the BLM has clarified in the final rule that all facilities are subject to the new requirements, with operators required to come into compliance on a staggered schedule of between 1 and 4 years, depending on their levels of production. This was achieved by tying compliance to the requirement to apply for an FMP found in the new 43 CFR subpart 3173. These significantly extended time frames will give operators time to plan and budget for expenses in advance, while limiting the chances that there will be local or national shortages of equipment or technical expertise, as might have resulted from the original proposed, 180-day implementation period.

Several commenters noted that in proposed paragraph (c), the BLM limited LACTs to those with PD meters, and suggested that other types of meters should be allowed. Most of those commenters specifically requested that Coriolis meters be allowed, but some requested that any type of meter permitted in API standards be allowed. This would include PD, Coriolis, and turbine meters. The BLM partly agrees and has changed the rule to allow Coriolis meters to be used with LACTs. However, the BLM does not agree that turbine meters should be allowed. In the BLM's experience, confirmed by many industry sources, turbine flowmeters are less accurate than PD and Coriolis meters and are more subject to wear and/or damage. As a result, the BLM will continue to disallow turbine meters in LACTs. The change to allow Coriolis meters in LACTs is found in § 3174.8(a)(1). The definition of, proving standards for, and other specific requirements related to the use and operation of Coriolis meters are addressed by other sections of the final rule.

One commenter stated that § 3174.7(b) would require operators to generate an additional run ticket before proving, and that the BLM should take into account the additional cost associated with that extra run ticket. The BLM did analyze the financial impacts of increased run tickets in its Paperwork Reduction Act analysis, which was discussed in the proposed rule preamble. Another commenter pointed out that this additional run ticket is unnecessary in LACTs with flow computers as a flow computer is capable of implementing a new meter factor in the middle of a month without the operator having to close it. The BLM agrees and as a result of this comment, the BLM changed § 3174.12(b)(1) of the rule to remove the requirement that operators close a run ticket prior to proving LACT systems that utilize flow computers, which will reduce the overall cost to operators.

One commenter said the BLM should remove requirements in proposed §§ 3174.7(c) and 3174.8(b)(7) for S&W monitors at LACTs because there is no such thing as an ''S&W monitor.'' There are water monitors or water probes, the commenter continued, but water monitors are not part of any oil measurement system. Rather, operators use water monitors to divert the flow back to tanks for additional processing to remove large amounts of water from their production stream. The BLM agrees with this commenter's assessment. From a regulatory perspective, a water monitor should not be required equipment at a LACT because it does not help the BLM verify accurate measurement and net oil volumes. In the final rule, the BLM has incorporated LACT requirements from API 6.1 and eliminated the table in § 3174.7(c), along with the S&W monitor requirements in § 3174.8(b)(7).

Section 3174.7 paragraphs (d) and (e) retain current requirements that all components of a LACT system be accessible for inspection by the AO and that the AO be notified of all LACT system failures that may have resulted in measurement error. Numerous commenters stated that the term ''notify'' in paragraph (e)(1) was ambiguous and requested that the BLM define what forms of notification are acceptable and the time frame for notifying the AO. The BLM agrees that this term needs to be defined and has defined ''notify'' to mean ''to contact by any method, including but not limited to electronically (email), in-person, by telephone, by form 3160–5 (Sundry Notice), letter, or Incident of Noncompliance.'' This definition has been added to the definitions listed in 43 CFR 3170.3, part of the rulemaking that is replacing Order 3.

Numerous commenters stated that the 24-hour time frame in proposed paragraph (e)(1) regarding notifying the BLM of LACT system failure was: (1) Impractical, (2) Too restrictive; (3) Potentially unnecessary if the failure was small (less than 0.05 percent); (4) Unlikely to significantly affect the net oil volume; (5) Too expensive for operators to implement because additional monitoring equipment would be required; and (6) Would require speculation on the part of the operators as to when a malfunction occurred when no one was present at the time of the malfunction. Most commenters suggested requiring reporting within 7 days after discovery. The BLM partly agrees, and paragraph (e)(1) of the final rule now requires notification within 72 hours after discovery. This time frame will ensure that the BLM is able to verify that all oil volumes are properly derived and accounted for, and verify any alternative measurement method, meter repairs, or meter provings within a reasonable time frame without placing unnecessary burdens on the operator. Requiring notification within 72 hours will allow operators to deal with urgent situations while still being able to timely notify the BLM.

Section 3174.7 paragraph (f) of the proposed rule would have retained the current Order 4 requirement that any tests conducted on oil samples taken from the LACT system samplers for determination of temperature, oil gravity, and S&W content meet the same minimum standards set in the manual tank gauging sections. However, the section of the preamble describing proposed § 3174.7(f) incorrectly said the oil samples themselves had to comply with the standards in the manual tank gauging section, rather than the testing procedures used to measure temperature, gravity (density), and S&W content. One commenter pointed out that this section not only incorrectly implied that temperature is somehow calculated from the oil in the sample pot, it also incorrectly referred to the standard testing procedures designed for manual tank gauging, not for testing using automated samplers as required in LACTs. The commenter stated that the BLM should use the standards in API

8.1 for static (manual) tank gauging and the standards in API 8.2 and API 8.3 for automatic sampler systems in LACTs, rather than referencing incorrect methods. The BLM agrees that the proposed rule preamble contains an incorrect summary of the actual proposed regulatory requirement in § 3174.7(f), and that the correct reference should be API 8.1 for sampling in static (manual) sampling and API 8.2 and API 8.3 for automatic sampler systems within LACTs. With this clarification, § 3174.7(f) in the final rule remains unchanged, although the recommendation to incorporate API 8.2 and API 8.3 by reference is accepted. The reference to this requirement is in § 3174.8(b)(1).

Paragraph § 3174.7(g) prohibits the use of automatic temperature/gravity compensators on LACT systems. Although Order 4 requires these devices, this rule will require those automatic compensators to be replaced using an electronic temperature averaging device. Automatic temperature/gravity compensators are designed to automatically adjust the LACT totalizer reading to compensate for changes in temperature and, in some cases, for changes in oil gravity as well. Unfortunately, the accuracy or operation of these devices cannot be verified in the field and there is no record of the original, uncorrected, totalizer readings. As a result, there is no ability to create an audit trail for these systems. As explained in the proposed rule, the BLM believes that the use of these devices inhibits its ability to verify the reported volumes because there is no source record generated, and the devices degrade the accuracy of measurement. Because there are relatively few LACT systems that still employ automatic temperature/gravity compensators, the BLM does not believe this requirement will result in significant costs to the industry.

Several commenters objected to this requirement, stating that temperature averagers are expensive and not necessarily any more accurate than temperature compensators, and that this change would require operators to replace functioning equipment at significant cost for no readily apparent benefit. One commenter stated that existing equipment should be grandfathered as long as an audit trail exists, and that the BLM should provide scientific evidence that automatic temperature/gravity compensators are less accurate than temperature averaging devices. Other commenters said that the simultaneous demand for temperature averaging devices would drive up the cost of purchasing and installing these devices on LACT systems. Several commenters indicated that rather than bear such a cost, some operators would choose to shut in wells and cease production activities.

In response to these comments, the BLM conducted field surveys of the companies that made the comments and determined that, in fact, they had very few LACTs that are still using automatic temperature/gravity compensators. Indeed, one of the companies had only one such LACT. The fact that very few LACTs still use automatic temperature/gravity compensators was confirmed by a major LACT manufacturer who stated that they sell very few automatic temperature/gravity compensators domestically, and that nearly all LACTs are currently equipped with temperature averagers. Further, this rule now provides for a phase-in of this new equipment over the next 1 to 4 years, based on when operators receive their FMP approvals, and the cost is relatively inexpensive (roughly $6,500 per LACT for the equipment). Regarding scientific studies or other data showing temperature averagers are more accurate, the BLM is not aware of any studies that show this. The main reason for the prohibition is that a temperature compensator is a mechanical device that does not have the capability for recording an ''audit trail,'' and therefore is inconsistent with the BLM's production accountability obligations. For these reasons, no change was made in this final rule.

Section 3174.8 LACT System—Components and Operating Requirements

Section 3174.8 contains LACT system components and operating requirements.

This section is closely related to § 3174.7 in that § 3174.7 contains general requirements for LACTs and states that LACTs must meet the construction and operation requirements and minimum standards of § 3174.8. Section 3174.8 goes into detail on what those requirements and standards are. Consequently, many of the comments on this section are closely related to comments received on § 3174.7.

In the proposed rule, § 3174.8(a) listed the components that each LACT must include. Several commenters said the BLM should not be so prescriptive and should instead require operators to comply with the appropriate API standards. One commenter stated this change would eliminate confusion and make it clear that Coriolis meters would be allowed as part of LACTs. In general, the BLM agrees that the original language was too prescriptive and may have inadvertently disallowed the use of Coriolis meters with LACTs. As a result of these comments, the final rule now simply requires LACTs to meet the standards prescribed in the applicable API sections. The list of all of the components required in LACTs has now been deleted from paragraph (a) and replaced with a statement that each LACT must include all equipment listed in API 6.1, with certain listed exceptions. The LACT components listed in § 3174.8(a) are related to requirements for PD and Coriolis meters and electronic temperature averaging devices, and allow multiple means of applying back pressure to the LACT to ensure single-phase flow. LACTs must consist of meters that have been reviewed by the PMT, approved by the BLM, and identified and described on the nationwide approval list at the BLM Web site (*www.blm.gov*) (see § 3174.8(a)(1)). Initially, the BLM will have no PD or Coriolis meter make or models limitations, but starting 2 years after the effective date of the rule, operators can only use the PD or Coriolis meter makes and models that the BLM approves for use and lists on its Web site. To ensure that specific PD and Coriolis meters in use at that time meet with BLM approval, the BLM encourages operators, manufacturers, or other entities (*e.g.,* trade associations) to pursue equipment approval prior to use.

One commenter stated that proposed § 3174.8 did not refer to industry standards for automatic sampling systems used with LACT and Coriolis meter systems, and that failure to provide minimal requirements could result in samples which were not representative, and therefore erroneous. The commenter also stated that proposed paragraph (b)(4), pertaining to standards for mixing of samples, should instead prescribe compliance with API 8.3, which contains the appropriate standards. Another commenter stated that proposed § 3174.8(a) did not mention an inline mixer or any pressure/temperature instrumentation, and asked if these items were prohibited or just not considered necessary. The same commenter stated that proposed § 3174.8(b)(2) discussed sample probe locations when standards for automatic sampling had not yet been incorporated into the rule, and requested that rather than restating portions of the standards in the rule, the BLM should incorporate API MPMS Chapters 8.2 and 8.3 into the rule.

The BLM agrees with the points raised in these comments and so, in the interest of eliminating uncertainty and errors, the final rule includes industry standards for automatic sampling systems and for mixing of samples. The final rule now includes a requirement that sampling and mixing of samples must comply with the standards in API 8.2 and API 8.3, respectively.

One commenter stated that the requirement in proposed § 3174.8(a)(10) and (b)(13) to have a back pressure valve and check valve downstream of the LACT could be met by allowing operators to use another common industry practice of placing a pump downstream. The BLM agrees that this arrangement would meet the intent of the requirement, which is to ensure single-phase flow through the meter, and has changed the rule accordingly. The revised requirement is more flexible and is found in the renumbered final rule at § 3174.8(a)(3).

One commenter noted that in proposed § 3174.8(a)(7), the BLM limited LACTs to only using a PD meter, and said that any type of meter permitted in API standards should be allowed. These standards include PD, Coriolis, and turbine meters. The BLM partly agrees and has changed the rule to allow Coriolis meters because field and laboratory testing have proven the Coriolis meter to be reliable and accurate. However, the BLM does not agree that turbine meters should be allowed. In the BLM's experience, confirmed by many industry sources, turbine flowmeters are less accurate and are more subject to wear or damage. As a result, the BLM will continue to prohibit the use of turbine meters in LACTs. The change to allow Coriolis meters in LACTs is reflected in § 3174.8(a)(1) of the final rule. References to the definition of, proving standards for, and other specific requirements for Coriolis meters are contained throughout the rule in appropriate sections.

Section 3174.8(b) describes the system operating requirements for LACTs. Multiple comments were received on this section, many of which focused on making the requirements less prescriptive and instead referencing API standards more extensively.

In general, in response to numerous comments that the proposed rule lacked flexibility, we have removed most of the prescriptive requirements in proposed § 3174.8(b). This section now requires operators to follow the sampling-process standards in API 8.2 and API 8.3 (the equipment and procedures to obtain and properly mix a representative sample); the standards for measuring the gravity (density) and S&W content of those samples in API 9.1, API 9.2, API 9.3, and API 10.4; the standards for flow measurement using electronic meter systems in API 21.2; the standards for temperature determination in API 7; and the standards for calculating net oil volumes for each run ticket in API 12.2.1 and API 12.2.2. All of these API standards are incorporated by reference and listed in § 3174.3.

One commenter objected to the BLM's requirement in proposed § 3174.8(b)(1) that LACTs include an electrically driven pump sized to ensure: (1) A discharge pressure compatible with the meter used; and, (2) That the flow in the LACT main stream piping is turbulent, such that the measurement uncertainty levels proposed in § 3174.3 are met. Instead, the commenter suggests that the BLM should require LACTs to meet uncertainty requirements without being so prescriptive. Another commenter stated that the BLM should be more flexible about the types of S&W monitors that would be allowed under proposed § 3174.8(b)(7) because some manufacturers do not make the types of plastic-coated probes that this section required. The commenter also suggested that existing S&W monitoring technologies should be grandfathered. Several other commenters stated that the requirement for a back pressure valve in proposed § 3174.8(b)(13) was too prescriptive and did not give operators the flexibility to use other methods to achieve the same result that back pressure valves provide—maintaining single-phase (oil-only) flow through the LACT meter. As discussed earlier, the BLM is keeping the requirement that LACT systems contain a back-pressure valve in the final rule at § 3174.8(a)(3), but we agree with commenters that the requirement needs to be more flexible, and we have added language that gives operators the option of using other controllable means of applying back pressure to ensure single-phase flow. Also in response to these comments, the BLM removed most of the prescriptive requirements in proposed § 3174.8(b) and replaced them with a requirement that operators meet the LACT system operating standards outlined in the applicable API standard incorporated by reference into the proposed rule. The only requirements that are spelled out in paragraph (b) are those requirements that are in addition to or different from standard API practices or that clarify which API standards are applicable.

Several commenters expressed concern that retrofitting or replacing existing equipment to meet the requirements of § 3174.8 was unnecessary and prohibitively expensive, and that existing facilities should be grandfathered, with some also suggesting that bringing existing facilities into compliance within the proposed 180-day implementation timeframe was either too expensive, impossible, or both. In response to these comments, the BLM has clarified in § 3174.2 in the final rule that all equipment must comply with the new requirements, with operators required to come into compliance on a staggered schedule of between 1 and 4 years, depending on when they receive their FMP approvals, which is based on their production levels. This significantly extends the compliance timeframe and gives operators time to budget and plan for any required changes, while limiting the chances that there will be local or national shortages of equipment or technical expertise, such as might have resulted from the proposed 180-day implementation period.

One commenter stated that proposed § 3174.8(b) should be revised to include a densitometer as optional equipment in the list of components, and that if density is provided, recordable, auditable, and verifiable, then the sampler and sample pot should not be required, which would save operators the cost of those components and lab analyses to determine S&W content. The commenter further said that if the sampler is not included in the list of components, then S&W content must be reported as zero percent, and the entire volume passing through the LACT meter would be reported as 100 percent oil. The BLM understands that there may be cases in which the operator would be willing to consider the entire produced stream as 100 percent oil, but the BLM believes that omitting the sampler and sample pot would create the potential for added confusion, and it is likely that most purchasers are going to require a sample grind-out anyway. For these reasons, no change was made to the rule as a result of this comment.

One commenter pointed out that proposed § 3174.8(b)(11)(ii), which required a temperature averaging device to take a temperature reading at least once per barrel, did not accord with API 21.2, Subsection 9.2.8.1, which requires such devices to be flow proportional and take a reading at least once every 5 seconds. The BLM agrees and has changed the rule accordingly. This provision in the final rule has been renumbered as § 3174.8(b)(6)(ii) and now reads: ''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).''

Sections 3174.9 and 3174.10 Coriolis Measurement Systems

Sections 3174.9 and 3174.10 pertain to CMS, which are not addressed in Order 4. Order 4 allows only for the use of PD meters with LACT systems. The use of Coriolis meters in this rule is based on technological advancements that provide for measurement accuracy that meets or exceeds the overall performance standards in § 3174.4. Field and laboratory testing of Coriolis meters has proven them to be reliable and accurate meters when installed, configured, and operated correctly.

One commenter said the final rule should allow operators to use truck-mounted CMS and submitted summarized data to support their view. The summarized data indicates significant differences between manual-gauged volumes and truck-mounted Coriolis-metered volumes. A summary of these volume differences indicated that the truck-mounted Coriolis meter measured as much as 22.44 bbl less that the manual gauge measured. Missing from the data is the volume of the entire load. The BLM needs this information to understand how significant these variations are. The data also indicates significant differences in measured oil temperature (as much as 23 °F) and gravity (as much as 5 degrees) when compared to manual methods. The commenter did not explain these differences or explain or justify the data submitted. The BLM decided not to include the use of truck-mounted Coriolis metering in the final rule. Operators may seek approval to use the truck-mounted option through the PMT approval process, which is outlined in § 3174.13. The rule was not changed based on this comment.

Another commenter suggested that the CMS could be used for gas measurement, in addition to oil measurement. The BLM has noted this comment; however, this subpart is dedicated to the measurement of oil. The rulemaking that is replacing Order 5 is a more appropriate venue for considering this comment, and this comment was directed to that rule team. The comment did not result in a change to this rule.

Several commenters stated that the term ''CMS'' should not be used for a Coriolis LACT as it is simply a LACT. The BLM agrees with this comment and has no intention of replacing the term ''LACT'' with the term ''CMS.'' The rule as proposed was intended to allow the Coriolis meter to be used in a LACT as an alternative to the PD meter, or as a standalone meter independent of a LACT system. The term CMS refers only to the latter option. To clarify this issue, the final rule has been edited to state that a Coriolis meter may be used in a LACT *or* as a standalone CMS meter.

Section 3174.9(b) specifies that Coriolis meters that have been reviewed by the PMT, approved by the BLM, and identified and described on the nationwide approval list at the BLM Web site (*www.blm.gov*) are approved for use. Initially, the BLM will have no Coriolis meter make or model limitations on the approved list, but starting 2 years after the effective date of the rule, operators will only be able to use the Coriolis meter makes and models that the BLM approves for use and lists on its Web site. To ensure that specific Coriolis meters in use at that time meet with BLM approval, the BLM encourages operators, manufacturers, or other entities (*e.g.,* trade associations) to pursue equipment approval outlined in § 3174.2(g) prior to use. Installations meeting the requirements described in this section and § 3174.10 do not require additional BLM approval. CMS proving must meet the proving requirements described in § 3174.11 and measurement tickets would be required, as described in § 3174.12(b).

One commenter said requiring each operator to have its CMS approved would result in a large financial burden. The BLM disagrees because the PMT only needs to approve a particular make or model of Coriolis meters once. Once a meter make or model has been reviewed, approved, and posted on the BLM's Web site, the meter can be installed at any facility, subject to any COAs imposed by the PMT for its use. Existing installations that already meet the requirements in §§ 3174.9 and 3174.10 do not require additional BLM approval.[13]

Section 3174.9(c) requires that a CMS be proved following the frequency established under § 3174.11. This proving frequency will ensure that operators periodically prove the CMS to provide verification that the meter is within the allowable tolerances. There were no comments on this section.

Section 3174.9(d) requires that measurement (run) tickets be completed as required by § 3174.12(b). This establishes the measurement-ticket time periods and minimum requirements for information that must be included on the tickets. There were no comments on this section.

Section 3174.9(e) identifies the applicable API standards for the components that must be installed with a CMS at an FMP, and includes some additional requirements that operators using a CMS for oil measurement must follow. The proposed rule listed the components in exact order from upstream to downstream of a CMS. The BLM has opted to be less prescriptive in the final rule and is requiring operators to follow API 5.6 for the setup and installation of a CMS system.

One of the prescriptive requirements in proposed § 3174.9(e)(7) was for operators to install a density measurement verification point. One commenter asked that this term be defined. Since the BLM has removed the prescriptive requirements and this particular term from the rule, a definition is no longer needed. No change resulted from this comment.

Another commenter said the BLM needs to allow for a connection point for a pycnometer. As discussed earlier, the BLM has removed the prescriptive, step-by-step requirements in this section. Should an operator wish to use this density-determination option, API 5.6 does allow for a density verification point that could be used as the point for installing the pycnometer. There was no change to the rule as a result of this comment.

Section 3174.9(e)(1) and (2) sets accuracy thresholds for temperature and pressure measurement devices that are part of a CMS. These devices are required to calculate the CPL and CTL correction factors. The uncertainties of these devices will be used in the overall uncertainty calculation to ensure that the CMS meets or exceeds the uncertainty levels required by § 3174.4. There were no comments on this section.

Section 3174.9(e)(3) covers the options for handling S&W content when determining net volume. Measurement by LACT requires a composite sampling system and determines net oil volume by deducting S&W content. The CMS does not require a composite sampling system, but rather leaves the option to the operator to either install a composite sampling system to determine S&W content for deduction in net oil determination or to make no S&W content deduction in net oil determination. In practice, Coriolis meters may be used at the outlet of a separator. It may not be feasible to use a composite sampling system at the outlet of a separator due to high separator pressure, thus effectively precluding the ability to determine S&W content. Without the ability to accurately determine S&W content, § 3174.9(e)(3) will require operators to report the S&W content as zero. The BLM may consider options to use other

[13] Additional comments on the PMT and the procedure that the PMT will use to approve devices are addressed in the discussion of § 3174.13.

methods to determine S&W content should acceptable technology or processes be proposed in the future. However, the BLM will only approve an alternate method of S&W content determination if the resulting overall measurement uncertainty is within the limits of § 3174.4(a).

Several commenters stated that if the rule does not allow corrections for S&W content, operators will be required to report an inaccurate volume. The BLM agrees that failing to correct for S&W content could result in an inaccurate measurement of net volume of product sold. However, this rule gives the operator the option to determine S&W content; if the operator chooses not to install the necessary equipment to determine the accurate S&W content, then no deduction will be allowed. The inclusion of the CMS as a method to measure production does not make this the sole means of measurement. It will be at the discretion of the operator to determine which method of measurement is most effective for their operation. In certain operations where a composite sampling system cannot be installed, and the operator determines reporting S&W content as zero is inappropriate for their operation, other measurement options may be available, though the operator will have to seek review through the PMT. No change to the rule resulted from these comments.

Relatedly, several commenters stated that the BLM should allow other methods to determine S&W content. The BLM agrees that other methods could be allowed, but the BLM does not currently have the data to review those options. As noted, under the final rule, an operator wishing to use a different option for determining S&W content will have to seek approval through the PMT process, as outlined in § 3174.13. No change resulted from this comment.

Section 3174.9(e)(4) requires single-phase flow through the CMS by means of applied back pressure. The proposed rule would have required operators to use a back pressure valve downstream of the Coriolis meter to achieve single-phase flow. Several commenters stated that there are other means of applying back pressure that are just as effective as using a back pressure valve, such as pumps downstream of the CMS. The BLM agrees and has changed the rule as a result of this comment. Instead of allowing only a back pressure valve, the BLM will allow the operator to use any means to apply sufficient back pressure to ensure single phase flow, so long as the approach meets the requirements of API 5.6.

Section 3174.9(f) allows the API oil gravity to be determined by using one of two methods: (1) From a sample taken from a composite sample container; or (2) Directly from the average density measured by the Coriolis meter. This choice accommodates situations in which it is not feasible or an operator chooses to not install a composite sampling system due to economic or operating constraints. The BLM may consider other methods for determining the API gravity of the fluid, such as in-line densitometer devices. However, the BLM will only approve alternative methods if resulting overall uncertainty is within the limits in § 3174.4.

One commenter suggested that the BLM should incorporate by reference the guidelines in API 8.2 and API 8.3 on composite sampling. Because a sample from a composite sample container is an acceptable method for determining the API oil gravity, the BLM agrees that the industry standard should be included and has incorporated API 8.2 for automatic sampling and API 8.3 for mixing and handling of samples into § 3174.8(b)(1) of the final rule.

Another commenter stated that the use of Tables 5A and 6A is inappropriate and that the flowing density should be corrected in accordance with API 11.1. The BLM agrees that Tables 5A and 6A are outdated and should not be used and has removed the language that referenced Tables 5A and 6A and replaced it with a reference to API 11.1.

Another commenter stated that abnormal events should be excluded from the average density calculation. The BLM assumes the commenter is referring to the fact that water, sand, or gas breakout may occur during a normal flowing regime. Excluding these abnormal events from the average density is allowed under the final rule, so long as an audit trail is maintained showing the full-flow density, including the period of flow that has been removed from the average density calculation. There is no change to the final rule as a result of this comment.

Another commenter said that during proving, a density correction factor should be applied if the densitometer within the Coriolis meter varies from a master densitometer at the density verification point. The BLM disagrees with this comment. During the proving verification of the densitometer within the Coriolis meter, the density reading is compared to an independent density measurement. 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. If the Coriolis densitometer exceeds the manufacturer's specification density tolerance, then the meter must be repaired or replaced, or an alternative method of density determination must be approved for use. Any alternative method must result in an overall uncertainty that is within the limits in § 3174.4.

Section 3174.9(g) requires that the net standard volume be calculated following API 12.2.1 and API 12.2.2. The proposed rule listed this requirement in § 3174.10(g) and gave very prescriptive requirements for the calculation. However, in order to make the final rule less prescriptive and to rely on industry standards wherever possible and appropriate, the requirement has been moved to § 3174.9(g), and the prescriptive language has been removed in favor of the guidelines listed in API 12.2.1 and API 12.2.2.

Several commenters said that net standard volume cannot be calculated by current Coriolis meters or any flow meter for that matter. The BLM agrees with these comments and for that reason there are no requirements in this rule that the CMS, or any meter, calculate and display net standard volume. No change was made to the rule as a result of these comments.

Another commenter stated that operators should be allowed to apply a shrinkage factor to the net standard volume. The BLM disagrees because past experience in reviewing net oil determinations shows that applying a calculated shrinkage factor results in very high uncertainty for the metering systems. The resulting overall uncertainty would exceed the limits of § 3174.4. Should new methods or technology for applying shrinkage factors be developed and proposed for use in the future, the PMT process described in § 3174.13 would be used for review and approval of those methods or technologies. No change to the final rule has been made as a result of this comment.

§ 3174.10 Coriolis Meter for LACT and CMS Measurement Applications—Operating Requirements

Section 3174.10(a) establishes the minimum pulse resolution (*i.e.,* the increment of total volume that can be individually recognized, measured in pulse per unit volume) of 8,400 pulses per barrel for CMSs. Because this resolution is standard for PD meters, and is accepted by the BLM, the same standard applies to CMSs. The BLM did not receive comments on this section.

Section 3174.10(b) establishes the minimum standards and specifications for specific makes, models, and sizes of Coriolis meters. The specifications will allow the BLM to determine the overall measurement uncertainty of the CMS, to ensure that it meets the requirements of § 3174.4, and to help insure that the meters are properly installed.

One commenter recommended that the BLM remove the requirement for maintaining and submitting to the BLM upon request the Coriolis meter specifications found in § 3174.10(b). The commenter said this requirement is not necessary for uncertainty-based measurement limits. The BLM disagrees. In order for the BLM to conduct a complete inspection of the CMS, it is necessary that all information required by this section be available to ensure that the Coriolis meter is operating within its design parameters, on which the uncertainty for the meter is based. No change in the final rule was made as a result of this comment.

Proposed § 3174.10(b)(iv) required that the minimum amounts of straight piping be installed upstream and downstream of the meter. Several commenters said that Coriolis meters do not require any specific amount of straight piping. The BLM agrees that pipe-length restrictions in Coriolis meter installations do not affect accurate measurement and has removed any reference to straight-pipe requirements for Coriolis meters from the rule.

Section 3174.10(c) requires a non-resettable totalizer for indicated volume. This is to allow verification over multiple run tickets of gross production prior to any adjustments to net standard volume. There were no comments on this requirement.

Proposed § 3174.10(c) had a requirement for meter orientation. One commenter said the BLM should remove this requirement because it is too prescriptive and should instead require operators to follow API standards. The BLM agrees that the proposed language was too prescriptive. The final rule, in § 3174.10(e), now requires operators to follow API 5.6.

Section 3174.10(d) of the proposed rule required that the operator must notify the AO within 24 hours of any changes to any Coriolis meter internal calibration factors including, but not limited to, meter factor, pulse-scaling factor, flow-calibration factor, density-calibration factor, or density-meter factor. One commenter suggested that 24 hours is an unreasonably short period of time for this requirement, especially if the applicable changes occur on a weekend. The commenter recommended a period of at least 10 days, or a monthly report from the PLC log. After consideration of this proposed requirement, the submitted comment, and the proving requirements in the final rule, the BLM has decided to remove this notification requirement from the rule because any changes to a Coriolis meter internal calibration factor will require immediate proving of the meter as required in § 3174.11(d)(8). An additional notification provides no benefit to the BLM.

Section 3174.10(d) (paragraph (f) in the proposed rule) requires verification of the meter zero reading before proving the meter or any time the AO requests it. The proposed rule described the process for verifying the meter zero value. The BLM has changed the wording in the final rule to be less prescriptive and to require the operator to follow manufacturer guidelines. This gives the operator flexibility during the verification procedure.

Several commenters said that requiring flow to be stopped during meter verification is an additional step and may disrupt normal operations. The BLM agrees that in order to verify that the meter is operating within the manufacturers' specifications, operators are required to verify the meter zero with no fluid flow. However, the BLM disagrees that meter zero verification is a disruption to normal operations. According to API standards and manufacturer recommendations, Coriolis meter zero verification is a part of normal operations. As discussed above, the final rule has been changed to require operators to follow manufacturer guidelines for meter zero verification; however, the requirement to verify meter zero remains in the final rule.

Section 3174.10(e)(1) through (e)(4) (paragraphs (i)(1) through (i)(4) in the proposed rule) lists the information that the Coriolis meter must display onsite. As part of the BLM's verification process during field inspections, the AO must be able to access this information without the use of a laptop or other special equipment. A log must be maintained of all meter factors, zero verifications, and zero adjustments, and must be made available to the AO upon request. The proposed rule would have required operators to maintain the log onsite.

The BLM received several comments stating that the requirement for a log to be maintained onsite containing the meter factor, zero verification, and zero adjustments is not practical. Because this information will not need to be readily available onsite for the AO to complete an inspection, the BLM agrees with the commenters and has changed the final rule in § 3174.10(e)(4) to require that the log containing the meter factor, zero verification, and zero adjustments must be made available upon request.

One commenter stated that the requirement in paragraph (e)(2) for the meter to display the instantaneous pressure has no valid use. The BLM disagrees with this statement as this information is needed as part of routine inspections conducted by the AO to verify the flowing volume in a meter. No changes were made as a result of this comment. Another commenter said that some Coriolis meters do not have the ability to display the density in pounds per barrel as originally required by the proposed rule. After contacting Coriolis system manufacturers, the BLM has confirmed that not all Coriolis meters have the ability to display this particular unit of measurement. Therefore, as a result of this comment, the requirement to display the density in pounds per barrel has been removed and other units of measurement (pounds per gallon or degrees API) have been added in § 3174.10(e)(2)(i). One commenter said that daily volume totals may not be available for display. The BLM contacted manufacturers and confirmed that Coriolis meters are capable of displaying daily volume totals. As a result, there was no change in the final rule from this comment.

Section 3174.10(f) requires that audit trail information listed in § 3174.10(f)(1) through (4) be retained for the time period required in § 3170.7, which is part of the rulemaking to replace Order 3. One commenter said that the requirements in § 3174.10(f)(2) and (4) may force operators to add a flow computer to a Coriolis LACT, which exceed the requirements of a PD LACT. This comment does not make sense because a Coriolis meter almost always has a flow computer. If an operator chooses to configure a Coriolis meter in a LACT without utilizing a flow computer, and display only a totalizer reading, then the requirements of § 3174.10(f)(2) and (4) would not apply. No change resulted from this comment.

Section 3174.10(g) requires that each Coriolis meter have an operable backup power supply or nonvolatile memory capable of retaining all data. This is to ensure that during a failure, all audit trail data is preserved to maintain compliance with these regulations. There were no comments on this section.

Section 3174.11 Meter-Proving Requirements

Proposed § 3174.11(a) and (b) would have established that a meter would not be eligible to be used for royalty determination unless it is proven to the standards detailed in the proposed rule. The BLM received no comments on these paragraphs. The final rule specifies the minimum requirements for conducting volumetric meter proving for all FMP meters. Paragraph (a) in the proposed rule was carried forward to the final.

A table in proposed paragraph (b) referred readers to the applicable paragraphs of this proposed section that contained the minimum standards for proving FMP meters. The BLM received no comments on this table. Nevertheless, the BLM did not include the paragraph (b) table in the final rule because the table did not provide substantive clarity or expedite reader access to the relevant paragraphs. This change resulted in the re-lettering of all subsequent section paragraphs in the final rule.

Paragraph (c) in proposed § 3174.11 (re-lettered to paragraph (b) in the final rule), established the acceptable types of meter provers that can be used to prove an FMP LACT or CMS. The BLM received a few comments objecting to the meter-proving requirements in this section of the final rule because they are not consistent with the referenced API specifications. These comments are addressed in the following text.

Section 3174.11(b)(1) through (3) of the final rule describe and detail the requirements for acceptable meter provers, which include the master meters and displacement provers that are currently allowed under Order 4. Coriolis master meters, which were not addressed in Order 4, have been included in the final rule. The BLM believes that Coriolis technology has advanced to the point where Coriolis meters meet the accuracy and verifiability requirements required for master meters. The final rule does not allow tank provers to be used as an acceptable device for proving a meter. According to API standards, tank provers are not recommended for use on viscous liquids, which include most crude oils. Because there are few tank provers currently in use on Federal and Indian leases, this requirement will not result in a significant cost to industry. One commenter on paragraph (b)(1) stated that the BLM requirement for master meter repeatability of 0.0002 (0.02 percent) is inconsistent with API 4.5, which requires a repeatability of 0.0005 (0.05 percent). The BLM agrees with the commenter and made a change to the final rule consistent with the comment. The BLM believes that the paragraph (b)(1) repeatability requirement for master meter provers in the proposed rule was too restrictive and the API 4.8 (as referenced in API 4.5) specification of 0.0005 (0.05 percent) repeatability is within the uncertainty (±0.027 percent) of BLM requirements.

The BLM also made a change to the final rule based on a comment that the calibration of the master meter prover in the proposed rule was too frequent. The proposed rule required master meter provers to be calibrated no less frequently than once every 90 days. The BLM agrees that the 90-day frequency for proving master meters may be too frequent. The final rule changes the master meter calibration frequency to no less than once every 12 months, which is consistent with API 4.8, Subsection 10.2, which is referenced in API 4.5.

One comment on paragraph (b)(2) of this section said the BLM displacement prover calibration requirements contradict API Chapter 4.9. The BLM disagrees with the commenter since API 4.9 addresses calibration methods for displacement provers and not calibration frequency for displacement provers as specified in API 4.8. The BLM changed paragraph (b)(2) in the final rule by removing the prescriptive language found in paragraphs (b)(2)(i) and (ii) in the proposed rule, and by incorporating calibration frequency requirements of API 4.8, Subsection 10.

Section 3174.11(b)(3) of the final rule (§ 3174.11(c)(3) of the proposed rule) requires the base prover volume of a displacement prover must be calculated under API 12.2.4. The BLM received no comments and made no changes to this requirement.

Section 3174.11(b)(4) (paragraph (c)(4) in the proposed rule) establishes displacement prover sizing standards. These standards ensure that fluid velocity within the prover is within the limits recommended by API 4.2, Subsection 4.3.4. Displacement velocities that are too low (prover is oversized) can result in unacceptable pressure and flow-rate changes and higher uncertainty due to possible displacement device ''chatter.'' Displacement velocities that are too high (prover is undersized) can cause damage to the components of the prover. One commenter recommended replacing the proposed prover design language that referenced API 4.2 with language that references operating provers within design parameters set forth by the manufacturer and by API 4.8 and API 4.9.2. The BLM disagrees with the commenter that paragraph (b)(4) should reference API 4.8 and API 4.9.2 since these standards deal with prover operation and are not relevant to paragraph(b)(4) design standards. Paragraph (b)(4) is specific to displacement prover design, which is covered under API 4.2. The BLM did not change the final rule in response to this comment.

Section 3174.11(c) (paragraph (d) in the proposed rule) establishes the requirements for meter proving runs with respect to proving both the FMP LACT and CMS and the conditions required for proving these meter systems. The BLM received many comments objecting to certain requirements in proposed § 3174.11(d) that deal with meter proving runs. The BLM responds to these comments as follows.

Section 3174.11(c)(1) (paragraph (d)(1) in the proposed rule) expands on the current Order 4 requirement to prove a meter under ''normal'' operating conditions. This section defines limits of flow rate, pressure, temperature, and API oil gravity that must exist during the proving to be considered ''normal'' operating condition. The BLM added this requirement because it realized that the meter factor can change with changes in these parameters. For example, a meter factor determined at an abnormally low flow rate may not represent the meter factor at a higher flow rate where the meter normally operates. This paragraph also requires a multi-point meter proving if the LACT or CMS is subject to highly variable conditions. The multi-point meter proving establishes a minimum of three meter factors—one at the low end of the normal operating range, one at the midpoint, and one at the high end. An appropriate meter factor will then be applied according to § 3174.11(c)(6).

One commenter noted that paragraph (c)(1) (paragraph (d)(1) in the proposed rule) lacks specifics on what normal operating temperature conditions mean and another commenter said the language should be changed to reflect situations where normal operating conditions vary, such as at multi-metering sites, and suggested a language change to ''average for the batch period.'' The BLM agrees with the commenter that normal operating conditions, as they apply to oil temperature, were not adequately addressed in the proposed rule and that in some instances it may be difficult to identify the ''normal operating conditions'' of flowrate, pressure, temperature, and fluid density. The BLM added paragraph (c)(1)(iii) to the final rule to address normal oil operating temperature limits, which must be within 10 °F of the normal operating temperature. With this addition, paragraphs (d)(1)(iii) and (d)(1)(iv) in the proposed rule have been renumbered to paragraphs (c)(1)(iv) and (c)(1)(v) in the final rule.

The BLM made no change to the final rule regarding normal operating conditions to reflect variable metering conditions since this situation may be specific to regions and areas of the country and can be more adequately addressed by the specific BLM field office through the variance request process as outlined in § 3170.6, which has been established as part of the rulemaking to replace Order 3.

Section 3174.11 paragraphs (c)(2) through (c)(5) (paragraphs (d)(2) through (d)(5) in the proposed rule) provide the details for minimum proving requirements, such as requiring a minimum proving pulse resolution of 10,000 pulses per proving run or requiring the use of pulse interpolation, if this cannot be met, and setting a requirement to continue repeating proving runs until the calculated meter factor from five consecutive runs is within a 0.05 percent tolerance between the highest and lowest value. The new meter factor will be the arithmetic average of the five meter factors or average pulses from the five consecutive proving runs. This section also requires the meter factors to be calculated following the sequence described in API 12.2.3. We received two comments on paragraph (c)(2) of this section. One commenter addressed the requirement that, during proving runs, there be a sufficient volume to generate at least 10,000 pulses from the FMP meter that is being proved. The commenter did not believe that the 10,000-pulse requirement is reasonable and said it would disallow the use of small-volume provers (SVPs). The BLM disagrees with the commenter on both points. The 10,000-pulse-per-proving-run resolution in the rule follows the API standard and the rule specifically allows small-volume provers as long as they meet the additional requirements in paragraph (c)(2). The BLM did not change the final rule in response to this comment. However, the BLM believes that it is appropriate to add clarifying language to paragraph (c)(2) in the final rule that reminds readers of the 10,000-pulse requirement in API 4.2, Subsection 4.3.2. Another commenter asked why the proposed rule did not specifically address SVPs. SVPs come under the requirements for displacement provers and, under paragraph (c)(2), are required to use pulse interpolation as outlined in API 4.6, since their volume generates less than 10,000 meter pulses per proving run. The BLM did not change the final rule due to this comment.

Two commenters on paragraph (c)(3) objected to the requirement that the five consecutive meter-proving runs have a repeatability of 0.0005 (0.05 percent), saying that three proving runs could accomplish the same uncertainty. The BLM disagrees with these commenters and has decided to retain Order 4's requirement of a minimum of five proving runs. The BLM believes that this requirement achieves the desired consistency and uncertainty levels. The BLM made no change to the final rule due to these comments.

One commenter on paragraph (c)(4) recommended that the BLM adopt the use of an average meter factor as determined from API 12.2.3. Upon review of this comment, the BLM agrees with the commenter that guidance on the calculation of the average meter factor is appropriate. Due to this comment, the BLM changed the final rule to incorporate API 12.2.3, Subsection 9 for purposes of calculating the average meter factor.

Section 3174.11(c)(5) of the final rule (§ 3174.11(d)(5) of the proposed rule) requires that meter factor computations must follow the sequence described in API 12.2.3. The BLM received no comments and made no changes to this requirement.

Section 3174.11(c)(6) (paragraph (d)(6) in the proposed rule) gives operators two methods for determining the multiple meter factors that are required under § 3174.11(c)(1)(v). The first method is to combine the meter factors into a single arithmetic average. The second method is to curve-fit the meter factors and incorporate a real-time dynamic meter factor into the flow computer (this will apply primarily to CMS). Neither multi-point provings nor multi-point meter factors are discussed in Order 4. One commenter indicated that averaging meter factors was only valid in regions where impacts of nonlinearities are minimal and recommended deleting § 3174.11(c)(6)(i). The BLM conducted further research into this comment and agrees with the commenter that averaging meter factors is only valid under certain conditions. Additional language pertaining to how to use the multiple meter factors is added to the final rule in paragraph (c)(6). This language will only permit the use of averaging meter factors if all meter factors in the range are within approximately ±0.10 percent of the average. It will also limit the use of the dynamic meter factor option to prevent any two neighboring meter factors that differ by more than approximately 0.2 percent from being used to derive a dynamic meter factor.

Sections 3174.11(c)(7) and (c)(8) (paragraphs (d)(7) and (d)(8) in the proposed rule) set the minimum and maximum values that are allowed for a meter factor, both between meter provings and for initial meter factors for newly installed or repaired meters. These meter-factor ranges are not changed from Order 4. The BLM received no comments on paragraphs (c)(7) and (8).

Section 3174.11(c)(9) (paragraph (d)(9) in the proposed rule) allows back pressure valve adjustment after proving only within the normal operating fluid flow rate and fluid pressure as prescribed in proposed § 3174.11(c)(1). If the back pressure valve is adjusted after proving, the ''as left'' fluid flow rate and fluid pressure must be documented on the proving report. The BLM is requiring this documentation based on its field observations, which have shown this practice to affect the meter factor in certain areas of the country. Specifically, the BLM has observed that a change in back pressure outside the proving conditions can, in some cases, result in operators reporting incorrect volumes. Allowing back pressure valve adjustment after proving is not intended as a means to circumvent the displacement prover minimum and maximum velocity requirements in § 3174.11(b)(4) of the final rule. Order 4 has no specific requirements relating to the adjustment of the back pressure valve after proving. The BLM received no comments on paragraph (c)(9).

Section 3174.11(c)(10) (paragraph (d)(10) in the proposed rule) sets standards for the pressure used to calculate a CPL factor for a LACT's composite meter factor. It also prohibits the use of a composite meter factor for Coriolis meters because they have the capability to use a true average pressure over the measurement ticket period in the calculation of an average CPL factor. The use of a composite meter factor is intended to make measurement tickets easier to complete because the CPL factor is already included in the meter factor. This is typically not an issue with a Coriolis meter because of the advanced capability of the flow computer to which it is connected. One commenter stated that most Coriolis meters in the field do not have the capability to calculate a CPL factor and replacing them with a Coriolis meter that could calculate a CPL factor would be prohibitively costly. The BLM agrees with the commenter regarding the CPL factor capability currently available in existing Coriolis meters. However, the final rule does not require operators to have a Coriolis meter with this CPL factor feature. Therefore, the BLM made no change to the final rule as a result of this comment.

Section 3174.11(d) (paragraph (e) in the proposed rule) establishes the minimum FMP meter-proving frequencies, and specifies certain events that will trigger additional meter provings. This section contains the meter-proving requirements that were previously located in the LACT section of Order 4 and consolidates in one place all of the meter-proving requirements for both LACTs and CMSs.

The BLM received many comments that objected to the provision in paragraph (d)(2) (paragraph (e)(2) of the proposed rule) that sets a threshold for when operators who run large volumes of oil through their meters must conduct additional FMP meter provings. The proposed rule would have required operators to prove their FMP meters each time the registered volume flowing through their meters increased by 50,000 bbl or quarterly, whichever occurred first. Currently under Order 4, an FMP meter must be proven at least quarterly, unless total throughput exceeds 100,000 bbl per month, in which case the meter must be proven monthly.

The BLM's rationale in the proposed rule for changing the proving threshold to 50,000 bbl/month was that it would have affected only about 5 percent of existing LACT systems nationwide, yet would have ensured that meter-factor changes would be corrected before large volumes of production were measured incorrectly, which could have an adverse impact on Federal or Indian royalty determinations.

Many commenters objected to the proposed meter-proving-frequency threshold of 50,000 bbl/month. Most commenters said this new meter-proving frequency would require them to perform excessive and costly meter provings in locations where the meters may not be easy to access, especially in bad weather. The BLM agrees that the 50,000 bbl/month threshold may be excessively costly and, after reviewing potential economic impacts, has decided to use a 75,000 bbl meter-proving frequency threshold in the final rule. This 75,000 bbl throughput threshold was determined by performing a statistical analysis to determine the volume at which the expected value of royalty under- or overpayment due to meter factors equals the $550 average cost of proving a meter. The royalty revenue impact depends not only on volumes but also on oil prices. The 50,000 bbl/month threshold in the proposed rule was determined when the U.S. Energy Information Administration's (EIA) 10-year West Texas Intermediate crude oil spot price was expected to average $95/bbl. Since then, the EIA's predicted 5-year average crude oil price has dropped significantly, to $67.58 per barrel. The BLM does not find the 50,000/bbl meter-proving threshold to be appropriate under this predicted lower oil-price environment.

The BLM also revised the maximum and minimum proving frequencies for meter proving on higher-volume FMPs. Under Order 4, operators were required to prove their meters at least quarterly or, if total throughput exceeded 100,000 bbl/month, then they were required to prove monthly. In this final rule, operators must prove their meters every 3 months (quarterly), or each time the registered volume flowing through the meter increases by 75,000 bbl, but no more frequently than monthly. For example, if a meter hits the 75,000 bbl threshold every 6 weeks, the operator must prove it every 6 weeks. If a meter has a 75,000 bbl throughput every 2 weeks, the operator must prove it once a month. The final rule was changed to include this new language.

Two commenters on paragraph (d)(2) said meter-proving frequencies should be increased, based on a lower volume of throughput threshold, and another commenter said that frequent proving would increase accuracy. The BLM does not agree that the final rule should further increase the proving frequency beyond what was presented in the proposed rule. The comments lacked any substantive basis and did not justify how an increased proving frequency would result in increased accuracy or how the costs of those additional provings would be justified by any reduction in royalty risk. The BLM believes the proving frequency in the final rule is justified and results in the required accuracy. The BLM did not change the final rule in response to these comments.

One commenter on paragraph (d)(6) of § 3174.11 (paragraph (e)(6) of the proposed rule) said that requiring a meter proving due to a change in normal operating conditions was not practical and not needed. The BLM disagrees with this commenter and agrees with another commenter who, in his comment on paragraph (e), pointed out that temperature extremes in places like Alaska or North Dakota have a large impact on meter-factor change between different proving runs. Because a change in the normal operating conditions could significantly affect the meter factor, and therefore the accurate measurement of the oil volumes, the BLM made no change to the final rule due to this comment.

Paragraph (d)(7) in § 3174.11 (paragraph (e)(7) in the proposed rule) also expands the current Order 4 requirement that operators prove their meters after repair. The new requirements require proving any time the mechanical or electrical components of the meter have been changed, repaired, or removed. In addition to those circumstances, paragraph (d)(8) requires an operator to also prove its meter after internal calibration factors have been changed or reprogrammed. One commenter asked whether meters used in flowback operations are subject to the requirements in this section. Flowback meters are not required to comply with this rule's meter-proving requirements because flowback operations take place prior to the operator's receipt of an FMP approval under § 3173.12, and more importantly meters used in these operations are not FMPs. The BLM did not change the final rule based on this comment.

One commenter said that after initial meter installation, a period of 2 weeks should pass before the meter is proved. The commenter did not justify a 2-week delay. The BLM believes that a meter should be proved as soon as is reasonably possible. The BLM expects that meters will be proven immediately after installation. The BLM did not change the final rule based on this this comment.

One commenter said that paragraph (d)(7) (paragraph (e)(7) in the proposed rule) is vague. The commenter specifically complained about language that required a meter proving after the mechanical or electrical components of the meter have been, among other things, ''opened.'' The BLM agrees with the commenter and changed the final rule so that the paragraph, in its entirety, now requires a meter proving after ''the mechanical or electrical components of the meter have been changed, repaired, or removed'', and added (d)(8) to prove after ''internal calibration factors have been changed or reprogrammed.'' Another commenter questioned the need to reprove a meter each time its secondary element (transducer) or tertiary device is changed. The commenter contends that these elements have no direct effect on the meter performance. The BLM agrees with the commenter in part. An element can impact the accuracy of the measurement if it is not measuring temperature and pressure accurately. Changing out either of these elements would not require the meter to be reproved, but would require the new element(s) (transducers) to be verified upon their replacement as is required under §§ 3174.11(f) and (g), and temperature and pressure transducer verification, respectively, during a meter-proving operation. The BLM revised the final rule § 3174.11(f) and (g) to address the commenter's concern by making it clear that a change out of either one of these elements would not require the meter to be reproved, but would require the new element(s) (transducers) to be verified upon their replacement.

Section 3174.11(e) (§ 3174.11(f) in the proposed rule) establishes what operators must do when there is excessive FMP meter factor deviation. This situation occurs when a meter factor, which is established in two successive provings, exceeds the allowable meter factor deviations. This section requires operators to take steps to bring the FMP meter back into compliance. It also requires operators to re-calculate the amount of production that was measured during the time period between these instances of excessive meter factor deviation. Paragraph (e) also requires operators to show the most recent meter factor and describe all subsequent repairs and adjustments on the proving reports that are required in paragraph (i) of this section.

Section 3174.11(e) maintains the Order 4 requirements for excess meter factor deviation and the required actions if proving reflects a deviation in meter factor that exceeds ±0.0025 between two successive meter provings.

The BLM received comments objecting to the paragraph (e) requirement that the FMP meter be removed from service when found defective or when the meter factor is outside the proposed accuracy range. The comments raised the issue of temperature extremes, in places like Alaska or North Dakota, having a large impact on meter factor change from proving to proving, making it impossible for operators to meet the meter factor deviation requirement. The BLM agrees that changing temperatures do affect the proving meter factors. This situation could easily justify more frequent provings as the temperatures change, the commenter said. The BLM believes this issue is field office specific and is more appropriately addressed through the BLM's variance process, which is outlined in § 3170.6, part of the rulemaking that is replacing Order 3.

One commenter recommended changing the meter-factor deviation limits for meters from ±0.0025 to ±0.0050 because, the commenter said, it is standard industry practice to consider volume measurements as accurate if the meter factor changes by plus or minus 0.0025 or less. It typically is not until the differences in the meter factors are between plus or minus 0.0025 and 0.0050 that a correction is applied. The BLM reviewed API 4.8 to verify the commenter's claims on meter-factor deviation limits that are the industry standard. API 4.8 states common practice for custody transfer applications is to accept new meter factors within the range of 0.10 percent and 0.50 percent of the previous meter factor. The BLM did not accept this recommended change for several reasons: The commenter agrees it is standard industry practice to consider volume measurements as accurate if the meter factor changes by plus or minus 0.0025 or less, ±0.0025 deviation between meter proving runs is currently the maximum deviation allowed under existing Order 4, proposed deviation falls within the acceptable deviation range recommended in API 4.8, and it will not increase current reporting requirements or add costs, but will ensure measurement accuracy. The BLM made no changes to the final rule based on these comments.

Section 3174.11(f) (paragraph (g) in proposed rule) establishes standards for the verification procedure and the test equipment used in the temperature transducer verification. It states the limit threshold value required by the verifying sources as they pertain to the normal operating temperature of the tested fluid. It also requires that the temperature transducer and devices used as part of a LACT or CMS be verified as part of every proving.

The BLM received quite a few comments objecting to the new requirement that operators verify the temperature transducers during the meter-proving process. One commenter said that the proposed rule's meter-proving frequencies would result in excessive and costly transducer verifications if the temperature transducers had to be verified during each meter proving, since the proposed rule would have required operators to prove their meters each time they measured 50,000 bbl of oil, or quarterly, whichever occurred first. The BLM believes that this concern is no longer valid. Section 3174.11(d)(2) in the final rule has been revised and now requires operators to prove their meters every 3 months (quarterly), or each time the registered volume flowing through the meter increases by 75,000 bbl, but no more frequently than monthly. These changes reduced the burdens associated with the proving requirements in the proposed rule. Therefore, the BLM did not change the final rule in response to this comment.

One commenter objected to the requirement that operators use an insulated water bath in the field to perform the temperature transducer verification process, stating that this type of process belongs in a laboratory-type environment and not in a field environment. The BLM disagrees with this commenter since an insulated water bath is a common, acceptable method of verification. The rule also states the transducer may be verified by utilizing a test thermometer well located within 12 inches of the probe of the temperature transducer. The BLM did not change the final rule in response to this comment.

One commenter said that requiring operators to verify the temperature transducer as part of a LACT or CMS proving may require operators to acquire additional equipment and incur costs. The BLM agrees with the commenter that verifying the transducer will require an additional piece of equipment and potentially an initial cost to acquire test equipment, but believes third-party proving contractors already own such equipment. Moreover, the BLM believes routine transducer verification is vital to assure proper performance and to obtain an accurate liquid temperature for use in correcting for the thermal effects on the liquid, ensuring accurate oil measurement, and royalty determination. As a result, the BLM made no change to the final rule in response to this comment.

Another commenter said the requirement for verification of temperature averaging devices in § 3174.11(f) of the proposed rule conflicts with requirements in § 3174.6(b)(2) for temperature resolution and accuracy. The commenter did not say how this requirement conflicts. The BLM disagrees that there is a conflict because the temperature accuracy required for temperature verification is 0.5 °F, which is consistent with temperature accuracies presented in other sections of the final rule and with manufacturer's recommendations. For example, the temperature display minimum graduation must be to the 0.1 °F, as required in § 3174.8(b)(5)(iv), which means there is no practical difficulty in assessing compliance with the verification limits. The BLM made no change to the final rule in response to this comment.

Section 3174.11(f)(3)(i) and (ii) of the final rule (§ 3174.11(g)(3)(i) and (ii) of the proposed rule) requires that if the displayed reading of instantaneous temperature from the temperature averager or the temperature transducer and the reading from the test thermometer differ by more than 0.5 °F, the temperature averager or temperature transducer must be either: (1) Adjusted to match the reading of the test thermometer; or (2) Recalibrated, repaired, or replaced. Section 3174.11(g)(3)(ii) of the proposed rule only required that the difference in temperature readings be noted on the meter proving report and all temperatures used until the next proving be adjusted by the difference. The BLM received no comments to this section, but reconsidered the requirement and the potential tracking and measurement errors in adjusting temperature readings between provings and decided that if the temperature averager or the temperature transducer is unable to be adjusted to the correct reading then it must be recalibrated, repaired, or replaced.

Section 3174.11(g) of the final rule (paragraph (h) in the proposed rule) establishes the verification requirements for the pressure transducer during the meter-proving operations and states the threshold limit value required by the verifying sources as they pertain to the normal operating pressure of the tested fluid. It requires that the pressure transducer and devices used as part of a LACT or CMS be verified as part of every FMP proving and establishes standards for the verification procedure and the test equipment used in the pressure transducer verification. The BLM received many comments objecting to the new requirement that operators verify the pressure transducer during the meter-proving process. Two commenters said that the proposed rule's meter-proving frequencies would result in excessive and costly transducer verifications if the pressure transducers had to be verified during each meter proving. The BLM believes that this concern is no longer valid. As noted elsewhere, the proving burdens under this final rule have been reduced relative to the proposed rule. The proposed rule would have required operators to prove their meters each time they measured 50,000 bbl of oil, or quarterly, whichever occurred first. Section 3174.11(d)(2) of the final rule now requires operators to prove their meters every 3 months (quarterly), or each time the registered volume flowing through the meter increases by 75,000 bbl, but no more frequently than monthly. As a result, the BLM made no changes to the final rule in response to these comments.

One commenter said that requiring operators to verify the pressure transducer as part of a LACT or CMS meter proving may require operators to acquire additional equipment and incur costs. The BLM agrees that verifying the transducer will require an additional piece of equipment and potentially an initial cost to acquire test equipment, but we believe that third-party proving contractors already own or can acquire such equipment. The BLM believes routine transducer verification is vital to accurate oil measurement and royalty determination. The BLM made no change to the final rule in response to this comment.

One commenter had concerns with the requirement in paragraph (g)(1) (paragraph (h)(1) in the proposed rule) that the pressure sensor must be verified against a NIST-traceable device that is at least twice as accurate as the reference accuracy of the pressure sensor, saying the operator may not have test equipment capable of this accuracy. The commenter suggested that the BLM should allow equipment to be used that does not meet this accuracy requirement, and should provide guidance on how lower-accuracy equipment can be used. The BLM realizes that this high level of accuracy may not be achievable with test equipment the operator currently has and as a result has changed the rule in § 3174.11(g)(1) to require the test-pressure device to have a stated maximum uncertainty of no more than one-half of the accuracy required from the transducer being verified.

Section 3174.11(h) (paragraph (i) in proposed rule) establishes the density verification requirements during the meter proving operations and states the limit threshold values required by the verifying sources as they pertain to the normal operating density of the tested fluid. For Coriolis meters, paragraph (h) requires verification using API 5.6, Subsection 9.1.2.1 if measured density is used to determine API oil gravity (instead of a hydrometer or thermohydrometer, which is generally required under § 3174.6(b)(4)). This provides an independent verification that the Coriolis meter's density determination function is within the accuracy specification for that meter.

The BLM received a few comments objecting to the new requirement for density verification during the FMP meter-proving process for a variety of reasons. One commenter recommended that the final rule refer to API 8.1, API 8.2, and API 8.3 if the compared density samples come from a sampling system. The BLM agrees with this recommendation and changed the final rule by adding references to API 8.1, API 8.2, and API 8.3. These references provide guidance to operators for performing composite sampling to verify oil density as required in the final rule under § 3174.11(h).

One commenter said that using a CMS meter instead of a PD meter would impose additional costs on operators to verify the CMS' density measurement. The BLM agrees in part that using a CMS would require additional density verification over what would be required on a PD meter. However, it is up to the operator to choose which meter type to use. The BLM did not change the final rule as a result of this comment.

One commenter objected to the requirement for density verification during the FMP meter-proving process because, the commenter said, it would be costly and excessive to verify the transducer during each meter proving. The BLM believes that this concern has been addressed. The proposed rule would have required operators to prove their meters each time they measured 50,000 bbl of oil, or quarterly, whichever occurred first. Section 3174.11(d)(2) in the final rule has been revised and now requires operators to prove their meters every 3 months (quarterly), or each time the registered volume flowing through the meter increases by 75,000 bbl, but no more frequently than monthly.

Section 3174.11(i) (paragraph (j) in the proposed rule) requires operators to report to the AO all meter-proving operations and volume adjustments made after any LACT system or CMS malfunction. This section provides additional requirements for data that need to be included on the meter-proving report beyond what is currently required under Order 4. In one change to Order 4 requirements, the final rule requires operators to provide the unique meter or station ID number on each proving report as required under § 3174.11(i)(2)(i). This section includes requirements for verification of the temperature averager or temperature transducer, verification of the pressure transducer, and an addition to the final rule for density verification documentation, as applicable, as well as any ''as left'' conditions if the back pressure valve is adjusted after proving, which operators also would have to document on the proving report.

Many commenters asked that we clarify aspects of paragraph (i) (proposed paragraph (j)). One commenter recommended that we change § 3174.11(i)(2)(iii) and (iv) to only require temperature and pressure transmitter information, if verified. The BLM disagrees with this commenter on when to report temperature and pressure transducer data, since this information has to be verified as part of each FMP meter proving. The BLM made no change to the rule in response to this comment. Three commenters asked the BLM to specify the format of the meter proving reports since proposed paragraph (i)(3) specified no specific format. The proposed rule required the operator to submit the meter-proving report to the AO no later than 14 days after the meter proving. The BLM agrees with the commenters that this information should be added and changed the final rule to say that the meter proving reports may be transmitted to the AO either in hard copy or electronically.

In addition to the comments on specific provisions above, the BLM received a few general comments on § 3174.11. One commenter said the new regulations would impact marginal-producing wells and may force a premature abandonment of wells and a loss of public hydrocarbon resources. The commenter proposed that marginal and/or existing wells be exempt from both subpart 3174 and subpart 3175. The BLM disagrees that these regulations will force operators to abandon marginal wells. If an operator believes these regulations will force it to abandon a marginal well, that operator can obtain a variance from the regulations under § 3170.6, which is part of the rulemaking that is replacing Order 3. The BLM made no change to the final rule in response to this comment.

One commenter said the maximum and minimum velocity for PD meter provers was not relevant to SVPs and royalty issues associated with their use. The commenter recommended that the BLM adopt language that says, ''Provers must be operated within the design parameters of the manufacturer.'' The BLM disagrees with the commenter because the prover design requirements, including sizing by prover velocity, are found in the API standards incorporated in this rule. If the operator believes it can meet or exceed these requirements by other means, then the rule allows the operator to use the variance process outlined in § 3170.6. The BLM did not change the final rule in response to this comment.

Two comments, made by the same commenter, voiced concerns that the proposed rule was suited to lighter oil regimes and did not address the differences in measurement that characterize heavy oil, steamflood, and cyclic steam operations. The commenter was concerned that the proposed rule's accuracy requirements would increase operating costs for heavy-oil operators, resulting in possible violations of the measurement requirements. The BLM agrees with the commenter that these rules do not specifically address the measurement of heavy oil. However, these issues are field office specific and can be appropriately addressed through the variance process outlined in § 3170.6.

Section 3174.12 Measurement Tickets

Section 3174.12 specifies the data requirements for measurement tickets (run tickets) based on which method of oil measurement an operator uses, *i.e.,* tank gauging, LACT system, or CMS. These requirements were previously found in Order 3.[14] The purpose of the information in the run tickets is to enable the BLM to independently verify the quantity and quality of oil removed from the lease during production audits so as to ensure accurate measurement and proper reporting.

The BLM received several comments on this section. Some comments questioned the requirement to complete a run ticket prior to proving a LACT or CMS utilizing flow computers. One commenter stated that this requirement is unnecessary as a flow computer is capable of implementing a new meter factor in the middle of a run without closing the run. The commenter asserted that the flow computer does this by applying the original meter factor to deliveries that occurred from the beginning of the month up to the point of proving and then applying the new meter factor after the point of proving until the end of the month. The BLM agrees that flow computers are capable of utilizing two meter factors as the commenter described, and of retaining an audit trail capability to track this. As a result of this comment, § 3174.12(b)(1) of the final rule has been changed to remove the requirement to close a run ticket prior to proving for LACT systems utilizing flow computers.

One commenter stated that the proposed rule's run-ticket requirements for tank gauging did not specify a frequency for when run tickets will be required. The BLM disagrees with this comment as the proposed rule stated that measurement tickets must be completed ''immediately after oil is measured by manual tank gauging.'' The BLM believes that this language is clear as to how frequently a measurement ticket needs to be completed but modified the final rule to say, ''After oil is measured by tank gauging under §§ 3174.5 and 3174.6. . . .'' This change was made because the final rule allows the use of ATG equipment. The BLM made no changes to the rule as a result of this comment but did modify the requirements' language due to the inclusion of ATG equipment. The final rule now states ''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.''

We received several comments requesting that we remove the requirement to list on measurement tickets the name of the operator's representative certifying the measurements. It was suggested that operators do not have enough field personnel to witness every oil tank haul and therefore would not be able to ''certify'' every tank sale. The commenters argued that this requirement could increase confusion and expense, requiring operators to schedule a sale only when a ''company man'' can be present, and creating undue financial strain on operators having to hire staff to witness tank sales and nothing else. Another commenter said that the BLM needs to define the term ''certify.'' Upon reviewing this requirement and the comments, the BLM agrees with the commenters, and deleted this requirement in proposed § 3174.12(a)(14) from the rule. It should be noted, however, the operators remain responsible for the accuracy of information found on run tickets, irrespective of any requirement to certify the run ticket.

Several commenters requested that the BLM remove from the rule the requirement that operators notify the AO within 7 days regarding their reasons for disagreeing with a tank gauge measurement. The commenters said this requirement is impractical because, in the field, it may take up to 30 days for a transporter's run ticket to show up in the operator's accounting system. One commenter said that operators should be able to correct relatively minor run-ticket discrepancies without having to report them to the BLM. Upon reviewing these comments, the BLM believes this requirement may create confusion both within the BLM and among operators as to when exactly the AO should be notified. For example, would a simple calculation error warrant AO notification? Would the operator need to explore a potential discrepancy before notifying the AO? The BLM believes this requirement could lead to significant confusion, with minimal benefit to the BLM. Therefore, this requirement in proposed § 3174.12(a)(15) was removed from the rule. Instead, the BLM will address any run ticket discrepancies on a case-by-

[14] The information on a run ticket is considered a source record, as defined in § 3170.3, which is being promulgated as part of the rulemaking to replace Order 3. The retention requirements for such records is addressed in that rulemaking; however, the requirements as to substance are provided in this rule as explained above.

case basis during routine production inspections.

One commenter stated that it may not be possible to reset temperature- and pressure-averaging equipment and density-determining equipment back to zero upon closing a run ticket, as is required by paragraph (b)(2) of this section, which could result in some operators having to replace equipment. The BLM is not aware of any non-resettable averaging equipment in use on Federal leases. This requirement is in the rule to ensure that the temperature, pressure, and density, which are required to be included on each run ticket, represent the average temperature, average pressure, and average density of the oil that actually flowed through the meter during the run-ticket period. If there is any non-resettable averaging equipment in use on any Federal or tribal lease, operators will be required to replace it. No change to the rule resulted from this comment.

One commenter recommended that the BLM require hauler signatures on run tickets, but at the same time admitted that anyone can write or type someone else's name on a run ticket and not be the individual who is actually performing the task. The BLM agrees that a signature could identify a specific individual who filled out a run ticket, in case questions arise. But past experience with signature requirements resulted in BLM inspectors spending a lot of time tracking down signatures for no quantifiable benefit. For this reason, the BLM decided to not include a signature requirement. BLM regulations at 43 CFR 3163.2(f)(1) include penalties for any person who knowingly or willfully prepares, maintains or submits false, inaccurate or misleading reports, notices, affidavits, records, data or other written information. The BLM believes this provision addresses any circumstance under which someone falsely enters another person's name on a run ticket. By only requiring the name(s) of the individual(s) performing the tank gauging, we will be acquiring the data we need for our verification requirements. No change was made to the rule as a result of this comment.

Section 3174.13 Oil Measurement by Other Methods

Section 3174.13(a) provides that using any method of oil measurement other than tank gauging, LACT system, or CMS at an FMP requires prior BLM approval. Under § 3174.13(b), the BLM will use the PMT as a central advisory body within the BLM to review and recommend approval of industry measurement technology not addressed in these regulations. The PMT is a panel of BLM employees who are oil and gas measurement experts.

The process outlined in § 3174.13(b) for reviewing new equipment allows the BLM to keep up with technology as it advances and approve its use without having to update its regulations. Under the rule, if the PMT recommends new equipment or measurement methods, and the BLM approves, the BLM will post the make, model, range or software version, or measurement method on the BLM Web site (*www.blm.gov*) as being appropriate for use at an FMP for oil measurement going forward.

The PMT will consider new measurement technologies on a case-by-case basis. The BLM believes this process will be used as other technologies or methods are developed and their reliability is established. For example, the BLM considered other meters for inclusion in this rule, such as turbine meters and ultrasonic meters; however, it ultimately decided not to include them in this rule because at this time there is insufficient testing to validate their accuracy and reliability under all operating conditions. However, if in the future the data demonstrates that these meters meet the performance standards of the rule, the PMT will be able to recommend that these meters be approved for use.

If the PMT is able to make the required determination, it will recommend that the BLM approve the use of the applicable equipment or method, as is or subject to certain conditions. Such equipment or methods, and any applicable COAs, will be posted to the BLM Web site and be identified as being appropriate for use at an FMP for oil measurement without additional approvals from the BLM, subject to any limitations or conditions of use imposed by the PMT. Subsequent users of the same technology will not have to go through the PMT process, provided only that they comply with the identified conditions of use.

Section 3174.13(c) provides that the procedures for requesting and granting a variance under § 3170.6 cannot be used as an avenue for approving new technology or equipment. An operator can obtain approval of alternative oil measurement equipment or methods only through review, recommendation, and approval by the PMT under § 3174.13.

One commenter suggested that field-office staff are often in a better position than national office staff to collaborate with operators on pilot projects intended to prove alternative measurement methods. The BLM disagrees. Field-office staff typically do not have the necessary time and measurement expertise to conduct a complete analysis for approval of new technology. This rule includes a process for the BLM—through the PMT—to assess new technology and approve it when appropriate. Additionally, this rule responds in part to concern on the part of the Subcommittee, the GAO, and the OIG that the BLM lacked uniform national standards governing measurement. Leaving decisions about new equipment to field office staff would not address that concern.

Several commenters wanted to know what they will have to do to get equipment approved for use through the PMT and included on the BLM Web site. One commenter objected to any requirement that operators pay for third-party testing of equipment in order to receive approval by the PMT. Upon reviewing the rule and careful consideration of this comment, the BLM re-evaluated the approval process for equipment and transducers that will be listed on the BLM Web site and changed the rule to clarify that an operator requesting approval must submit performance data, actual field test results, laboratory test data, or any other supporting data or evidence that demonstrates that the proposed equipment will meet or exceed this rule's objectives. The final rule is revised by adding in § 3174.2(g) to explain how operators and manufacturers can obtain BLM approval for ATG equipment and specific meters, including approval of a particular make, model, and size, by submitting test data used to develop performance specifications to the PMT for review. Neither the proposed nor the final rule requires operators to pay for third parties to test equipment in order to receive PMT approval. However, should the submitted data fail to demonstrate to the PMT that the proposed equipment will meet or exceed this rule's objectives, the BLM may require additional testing before it grants approval.

One commenter objected to the creation of the PMT, claiming it will stifle innovation, not provide timely reviews, and discourage development of new technology by increasing ''red tape.'' The BLM disagrees and in fact believes the PMT will increase the utilization of new technology and expedite new approvals. The BLM believes that once the PMT is fully staffed, reviews could take 30 to 60 days, assuming that operators and manufacturers have performed the proper testing and that all pertinent data is submitted to the PMT. Once the PMT reviews the data and makes a recommendation, and the BLM approves a piece of equipment, it is approved for use across the country on all Federal and Indian onshore leases and no further approvals are required. This is not the case for the current variance process, which requires approval by each field office for each instance such equipment is proposed for use, resulting in a duplicative approval process with inconsistent results.

This commenter also said the BLM, the public, and industry would benefit from allowing companies to determine how they will meet the requirements of the regulation once it is in place, without the agency determining what equipment it will allow to fulfill the requirements of its regulation. The BLM agrees that a company should have the flexibility to determine how to best satisfy the performance requirements of the rule, but disagrees that the BLM should not be evaluating and approving equipment. The BLM has an affirmative obligation to determine that measurements on Federal oil and gas leases are meeting the applicable performance and verifiability standards. The final rule provides flexibility by including provisions that allow for variances for alternatives that meet or exceed the minimum requirements of the regulations and by including the PMT approval process in the rules to evaluate and approve new technology and measurement methods. The BLM believes that the final rule has already addressed the intent of this comment—to allow flexibility in measurement approaches. No change to the rule resulted from this comment.

One commenter suggested that the BLM should list approved technology and not specific makes and models of equipment. The BLM partly agrees with the commenter, in that the PMT will be evaluating new technology and the list will include new technology as it is approved, but it will be approved and listed by make and model of the specific equipment based on the performance data. The BLM believes that there will always be manufacturing control and software differences that affect individual meter performance between competing manufacturers and these differences need to be captured in the uncertainty calculator. No changes to the rule resulted from these comments.

Section 3174.14 Determination of Oil Volumes by Methods Other Than Measurement

Section 3174.14 does not change Order 4's existing requirements for determining volumes of oil that cannot be measured as a result of spillage or leakage. This section includes, but is not limited to, oil that is classified as slop or waste oil.

The BLM received two comments on this section. The first commenter said the section requires the operator to confirm ''slop oil'' is not recoverable, and cannot be treated and sold, and provide documentation to this effect. According to the commenter: (1) The proposed rule did not define a process for the operator to follow; (2) This requirement could impact water disposal when bottoms are pulled from a tank; and (3) The language is very open ended. The BLM disagrees that the rule does not define a process. The language found in this section is simply a codification of existing requirements and practices. Additionally, the proposed and final rules state that the first determination the operator must make is the amount of production that cannot be measured due to spillage or leakage. The second determination the operator must make is whether the production is waste oil or slop oil. And the third step that an operator must take, depending on whether it is waste or slop oil, is to either demonstrate to the AO that it is not economically feasible to put the product into marketable condition or get AO approval to sell or dispose of the slop oil.

Regarding the second issue, the BLM notes that this is not a new requirement and it should not surprise operators that the requirements of this section could impact water disposal when bottoms are pulled from tanks should the contents meet the definition of waste oil or slop oil.

As for the third issue, the BLM agrees that the language is somewhat open-ended because it is intended to address all potential situations that might occur in the field. No change has been made to the rule as a result of this comment.

The second commenter said the rule should be changed to better define slop oil. The definition of slop oil is found in the definitions section of § 3170.3, part of the rulemaking that is replacing Order 3. This issue was addressed as part of that rulemaking; however, it should be noted that the BLM does not believe this definition is insufficient. No change has been made to the final rule as a result of this comment.

Section 3174.15 Immediate Assessments

Section 3174.15 identifies certain acts of noncompliance that are subject to immediate assessments. This section includes violations that are not subject to immediate assessment under existing regulations at 43 CFR 3163.1(b). These assessments are not civil penalties and are separate from the civil penalties authorized in Section 109 of FOGRMA, 30 U.S.C. 1719.

Order 4 does not provide for immediate assessments beyond those specified in 43 CFR 3163.1(b). However, the BLM continues to incur costs associated with correcting the violations identified in § 3174.15. Accordingly, this rule adds five new violations that are subject to immediate assessments.

As is explained in the proposed rule, the authority for the BLM to impose these assessments was explained in the preamble to the 1987 final rule in which 43 CFR 3163.1 was originally promulgated:

> The provisions providing assessments have been promulgated under the Secretary of the Interior's general authority, which is set out in Section 32 of the Mineral Leasing Act of 1920, as amended and supplemented (30 U.S.C. 189), and under the various other mineral leasing laws. Specific authority for the assessments is found in Section 31(a) of the Mineral Leasing Act (30 U.S.C. 188(a), which states, in part ''. . . the lease may provide for resort to [sic] appropriate methods for the settlement of disputes or for remedies for breach of specified conditions thereof.'' All Federal onshore and Indian oil and gas lessees must, by the specific terms of their leases which incorporate the regulations by reference, comply with all applicable laws and regulations. Failure of the lessee to comply with the law and applicable regulations is a breach of the lease, and such failure may also be a breach of other specific lease terms and conditions. Under Section 31(a) of the Act and the terms of its leases, the BLM may go to court to seek cancellation of the lease in these circumstances. However, since at least 1942, the BLM (and formerly the Conservation Division, U.S. Geological Survey), has recognized that lease cancellation is too drastic a remedy, except in extreme cases. Therefore, a system of liquidated damages was established to set lesser remedies in lieu of lease cancellation . . .
>
> The BLM recognizes that liquidated damages cannot be punitive, but are a reasonable effort to compensate as fully as possible the offended party, in this case the lessor, for the damage resulting from a breach where a precise financial loss would be difficult to establish. This situation occurs when a lessee fails to comply with the operating and reporting requirements. The rules, therefore, establish uniform estimates for the damages sustained, depending on the nature of the breach (53 FR 5384, 5387, Feb. 20, 1987).

All of the immediate assessments under this rule are set at $1,000 per violation. The BLM chose the $1,000 figure because it generally approximates what it would cost the agency to identify and document each of the violations in question and verify remedial action and compliance.

Some commenters argued that the immediate assessments in § 3174.15 are inconsistent with due process because there is no opportunity for an operator to correct its violations before an assessment is imposed. To the contrary, the use of immediate assessments for breaches of the BLM's oil and gas regulations is well established and is consistent with the notice requirements of due process. Operators obligate themselves to fulfill the terms and conditions of the Federal or Indian oil and gas leases under which they operate, and these leases incorporate applicable regulations by reference. Thus, the immediate assessments contained in the regulations act as ''liquidated damages'' owed by operators that have breached their leases by breaching the regulations (see, *e.g.,* M. John Kennedy, 102 IBLA 396, 400 (1988)). Operators are expected to know the obligations and requirements of the Federal or Indian oil and gas lease under which they operate; additional notice is not required.

A number of commenters said the $1,000 assessment amounts are ''excessive.'' One commenter said the BLM should adjust the assessment amounts on a case-by-case basis. The BLM does not agree. The $1,000 assessments are in line with the amounts needed for the BLM to recover costs for staff and processing time associated with the inspection process. A fixed schedule of assessments also ensures their impartiality and uniformity. No changes to the rule resulted from these comments.

Enforcement

As explained in the proposed rule, the final rule removes the enforcement, corrective action, and abatement period provisions of Order 3. In their place, the BLM will develop an Internal Inspection and Enforcement Handbook that will provide direction to BLM inspectors on how to classify a violation—as either major or minor—what the corrective action should be, and what the timeframes for correction should be. The AO will use the Inspection and Enforcement Handbook in conjunction with 43 CFR subpart 3163, which provides for assessments and civil penalties when lessees and operators fail to remedy their violations in a timely fashion, and for immediate assessments for certain violations.

As previously discussed in the proposed rule, the final rule allows the BLM to make a case-by-case determination of the severity of a violation, based on applicable definitions in the regulations. In deciding how severe a violation is, BLM inspectors must take into account whether a violation could result in ''immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income.'' (Definition of ''major violation,'' 43 CFR 3160.0–5.) Under the existing definition of ''major violation,'' which is not being revised as part of this rulemaking, the same violation could be major or minor, depending on the context.

Several commenters objected to this approach for a number of reasons. One concern was that if the BLM publishes an internal guidance document ''after the fact,'' meaning after the rule is final, industry will be precluded from commenting on or assessing the impact of such a document on their operations. Another concern was that a guidance document will create inconsistency between field offices and operators. However, the commenter provided no explanation as to how an internal guidance document will create inconsistency between field offices and operators, or what confusion industry will have concerning how the BLM enforces the regulations. In general, these comments misunderstand the nature of the Internal Inspection and Enforcement Handbook that the BLM will develop. The new Handbook will not establish new obligations to be imposed on the regulated community. Those obligations are spelled out in applicable regulations, orders, and permits, as well as the terms and conditions of leases and other agreements.

Other commenters questioned why the Inspection and Enforcement Handbook was not part of the public notice and comment process. Internal guidance documents that direct agency personnel how to implement existing agency policies are not required to follow the public notice and comment process. No change to the rule resulted from this comment.

Additional comments suggested that the BLM may not promulgate new binding regulations in internal ''guidance'' documents. The BLM agrees with this comment and will not be promulgating any binding regulations within the internal guidance document. The overarching enforcement infrastructure of 43 CFR subpart 3163 remains in effect, and the definitions of ''major violation'' and ''minor violation'' in § 3160.0–5 remain unchanged. It is these duly promulgated regulations (among other authorities), and not the Inspection and Enforcement Handbook, that will provide the legal basis for the BLM's enforcement actions; BLM's enforcement actions must be consistent with these regulations irrespective of what may be contained in its Inspection and Enforcement Handbook. As noted above, it is this rule and other duly promulgated regulations that establish the standards to which an operator will be held.

Several commenters asserted that removing internal enforcement provisions from the regulations that were promulgated with public notice and comment, and ''concealing'' them in non-public policy documents that can be altered without notice and in the absence of public input, is inconsistent with the requirements of the Administrative Procedures Act (APA). The BLM does not agree with these comments as they misunderstand the nature of the new Handbook. The operative requirements to which operators are subject are spelled out in duly promulgated regulations, consistent with APA requirements. Internal agency guidance documents on how to implement those requirements are not subject to the APA's notice and comment requirements. No change to the rule resulted from these comments.

A few other commenters said industry has a right to know by what standards they are being judged and penalized. The BLM agrees and believes this rule very clearly describes the standards industry must meet in the oil measurement context. As stated above, in deciding how severe a violation is, BLM inspectors will take into account whether a violation could result in ''immediate, substantial, and adverse impacts on production accountability, or royalty income'' (definition of ''major violation'', 43 CFR 3160.0–5.) One commenter suggested that the BLM provide internal standards to industry at the earliest opportunity. The BLM agrees and will make the internal Inspection and Enforcement Handbook available to the public once it is completed.

Several commenters expressed concern that industry has not seen any proposed violations that may result in enforcement actions prior to the BLM's adoption of the Inspection and Enforcement Handbook. The BLM wishes to further clarify what a violation is. Any deviation from the rules and regulations, without an approved variance from the AO, is a violation, and any violation will result in enforcement action. The Handbook will not alter that fundamental structure in any way.

Additional commenters said the BLM's process for developing violations and corrective actions is not transparent. Again, these comments misunderstand the nature of the forthcoming internal guidance. Operators are obligated to follow the rules and regulations applicable to their operations, including the requirements of this final rule, or they are in violation and subject to potential enforcement actions by the BLM. The Inspection and Enforcement Handbook will simply guide BLM staff on how to identify violations and provide guidance on which enforcement actions should be taken, it does not answer the underlying question of what is or is not a violation. No changes to the rule resulted from these comments.

Miscellaneous Changes to Other BLM Regulations in 43 CFR Part 3160

Because this rule replaces Order 4, the BLM is making two related changes to provisions in 43 CFR part 3160.

1. Section 3162.7–2, Measurement of oil, has been rewritten to be consistent with this rule.

2. Section 3164.1, Onshore Oil and Gas Orders, the table has been revised to remove the reference to Order 4.

The BLM received no comments on these sections and they remain as proposed.

C. General Comments on the Proposed Rule

Regulatory Burden

The BLM received numerous comments that said the cumulative economic impact of this and other rules that the BLM has adopted or plans to finalize in the coming months will result in unnecessary and restrictive regulations, increased burdens and costs to both industry and the BLM without any documented financial benefits to taxpayers, and job loss in the oil and gas industry. The commenters noted that in addition to this rulemaking, the BLM is finalizing rules that will update and replace Orders 3 and 5. In addition, on February 8, 2016, the BLM published in the **Federal Register** a proposed rule entitled Waste Prevention, Production Subject to Royalties, and Resource Conservation (81 FR 6616), which seeks to curtail the wasteful venting and flaring of Federal and Indian gas. Commenters also flagged the BLM's new regulations on hydraulic fracturing that were to go into effect on June 24, 2015 (The rule is currently vacated by order of the District Court of Wyoming, that Order is on appeal to the U.S. Court of Appeals for the Tenth Circuit.) The BLM does not agree with these comments for two primary reasons. First, this rule codifies existing requirements found in Order 4, adopts industry standards and practices that are already in use, and has built in compliance flexibility that increases opportunities for operators to deploy new technologies, potentially reducing costs. Notably, this rule expands compliance opportunities because, for the first time, it establishes measurement performance standards that can be used by operators to identify and evaluate alternative measurement methods and equipment. Second, improved accuracy also has the potential to benefit operators, because measurement uncertainty has an equal chance of favoring the government or the lessee.

Other commenters said that the costs to retrofit many of the facilities to bring them into compliance with this rule and the BLM's proposed rules on gas measurement and site security would outweigh any foreseeable economic benefits to operators and government entities. The commenters contend that the proposed rule would impose significant and harmful burdens on operators and the industry as a whole causing operators to shut in, plug, and abandon producing wells, possibly leading to a loss of royalty and tax revenue for the Federal Government, as well as tribal, State, and local governments. Several commenters recommended that the BLM withdraw the proposed rule at this time due to its negative economic impacts, and argued that the BLM could accomplish much of what it seeks to do through this proposed rule by simply updating the content of Orders 4 and 5 to reflect current voluntary consensus standards developed by professional industry groups. The BLM disagrees with the suggestion that these rules are unnecessary and will result in plugged wells, or lost jobs. First, the current economic conditions in the oil and gas sector identified by the commenters are a direct result of the significant drop in oil prices over the last year and a half, which has been accounted for in the threshold analyses performed by the BLM. For example, the recent drop in oil prices led the BLM to change the various thresholds between draft and final rule, as explained in this preamble. Second, with respect to the suggestion that BLM should have simply updated Orders 4 and 5 with references to the relevant industry standards, it must be noted that such an approach was not available to the BLM. Order 4 was promulgated using the APA's Notice and Comment procedures; therefore any updates to it required BLM to undertake Notice and Comment rulemaking. Under those procedures, the BLM is forbidden from incorporating industry standards, unless it is incorporating them into codified regulations, which is the primary reason this rule is being codified.

With respect to the concerns about cost, the BLM believes that this rule will increase opportunities for operators to reduce costs thanks to the rule's built-in flexibility. As noted, this rule includes specific performance standards that will enable operators to identify and evaluate alternative methods and equipment for oil measurement. In addition, the rule includes provisions expressly authorizing ATG systems and the use of Coriolis meters (either as a component of a LACT system or as a standalone metering system). Finally, as explained elsewhere, the rule incorporates the latest industry standards and establishes a PMT to evaluate new equipment and methodologies, so that the BLM can review and approve such equipment and methodologies as they are developed. This flexibility is not available in the current Order 4, which requires operators to obtain case-by-case variances before they may use new equipment or methods.

Retroactivity

A number of commenters argued that the rule is impermissibly ''retroactive.'' These comments argued that the rule is retroactive because it will apply to measurement systems whose existence pre-dates the rule's effective date. While the BLM agrees that truly retroactive regulations raise legal concerns, those concerns are not implicated here because this rule is not retroactive. The comments misunderstand the nature of the ''retroactive'' regulations that the law disfavors. ''A law does not operate 'retrospectively' merely because it is applied in a case arising from conduct antedating the statute's enactment or upsets expectations based in prior law'' (*Landgraf* v. *USI Film Prods.,* 511 U.S. 244, 269 (1994) (internal citations omitted)). Rather, the test for retroactivity is whether the new regulation ''attaches new legal consequences to events completed before its enactment.'' *Id.* at 270. The rule at hand does not attach any new legal consequence to the past use of existing measurements systems. As the U.S. Court of Appeals for the District of Columbia Circuit has explained, the fact that a change in the law adversely affects pre-existing arrangements does not render that law ''retroactive:''

> It is often the case that a business will undertake a certain course of conduct based on the current law, and will then find its expectations frustrated when the law changes. This has never been thought to constitute retroactive lawmaking, and indeed most economic regulation would be unworkable if all laws disrupting prior expectations were deemed suspect.

Chemical Waste Mgmt., Inc. v. *EPA,* 869 F.2d 1526, 1536 (D.C. Cir. 1989). Thus, despite the fact that this rule may require companies to update or modify their existing measurement systems, the rule is nonetheless prospective—not retroactive—in nature. The obligation to accurately measure and account for oil produced from both new and existing facilities is ongoing and track the productions each day it occurs.

National Technology Transfer and Advancement Act of 1995

The National Technology Transfer and Advancement Act of 1995 (NTTAA), codified as a note to 15 U.S.C. 272, directs agencies to utilize technical standards that are developed by voluntary consensus standards bodies. In this rule, the BLM is adopting certain oil measurement standards developed by the API. Some commenters argued that the NTTAA obligates the BLM to adopt *all* oil measurement standards developed by voluntary consensus standards bodies. This position overstates the requirements of the NTTAA. The NTTAA does not require an agency to adopt voluntary consensus standards where it would be ''impractical.'' NTTAA Section 12(d)(3). The Office of Management and Budget's (OMB) guidance for implementing the NTTAA defines ''impractical'' to include circumstances in which the use of certain standards ''would fail to serve the agency's regulatory, procurement, or program needs; be infeasible; be inadequate, ineffectual, inefficient, . . . or impose more burdens, or be less useful, than those of another standard'' (OMB Circular A–119, pg. 20.) Furthermore, the OMB has explained that the NTTAA ''does not preempt or restrict agencies' authorities and responsibilities to make regulatory decisions authorized by statute . . . [including] determining the level of acceptable risk and risk-management, and due care; setting the level of protection; and balancing risk, cost, and availability of alternative approaches in establishing regulatory requirements'' (OMB Circular A–119, pg. 25.) The BLM has studied the available voluntary consensus standards for oil measurement and has chosen to adopt a workable suite of these standards that will meet the BLM's regulatory needs in an effective and feasible manner. To adopt all available voluntary consensus standards would be ''impractical'' in that it would involve the adoption of standards the BLM has judged to be less effective, feasible, or useful. In addition, the commenters reading of the NTTAA would, contrary to OMB guidance, preempt the BLM's statutory authority to promulgate rules and regulations that it deems necessary to accomplish the purposes of the MLA and FOGRMA.

III. Overview of Public Involvement and Consistency With GAO Recommendations

Public Outreach

The BLM conducted extensive public and tribal outreach on this rule both prior to its publication as a proposed rule and during the public comment period on the proposed rule. Prior to the publication of the proposed rule, the BLM held both tribal and public forums to discussion potential changes to the rule. In 2011, the BLM held three tribal meetings in Tulsa, Oklahoma (July 11, 2011); Farmington, New Mexico (July 13, 2011); and Billings, Montana (August 24, 2011). On April 24 and 25, 2013, the BLM held a series of public meetings to discuss draft proposed revisions to Orders 3, 4, and 5. The meetings were webcast so tribal members, industry, and the public across the country could participate and ask questions either in person or over the Internet. Following those meetings, the BLM opened a 36-day informal comment period, during which 13 comment letters were submitted. The comments received during that comment period were summarized in the preamble for the proposed rule (80 FR 58952).

The proposed rule was made available for public comment from September 30, 2015 through December 14, 2015. During that period, the BLM held tribal and public meetings on December 1 (Durango, Colorado), December 3 (Oklahoma City, Oklahoma), and December 8 (Dickinson, North Dakota). The BLM also held a tribal webinar on November 19, 2015. In total, the BLM received 106 comment letters on the proposed rule, the substance of which are addressed in the Section-by-Section analysis of this preamble.

Consistency With GAO Recommendations

As explained in the background section of this preamble, three outside independent entities—the Subcommittee, the OIG, and the GAO—have repeatedly found that the BLM's oil measurement rules do not provide sufficient assurance that operators pay the royalties due. Specifically, these groups found that the BLM needed updated guidance on oil measurement technologies, to address existing technological advances, as well as technologies that might be developed in the future. These groups have all found that the BLM's existing guidance is ''unconsolidated, outdated, and sometimes insufficient,'' and more specifically, that:

- BLM policy and guidance have not been consolidated into a single document or publication, resulting in the BLM's 31 oil and gas field offices using varying policy and guidance;
- Some BLM policy and guidance is outdated and some policy memoranda have expired; and
- Some BLM State offices have issued their own NTLs for oil and gas operations, which lack a national perspective and may introduce inconsistencies among the States with respect to the same types of operations.

The final rule addresses these recommendations by establishing nationwide performance requirements for oil measurement that addresses uncertainty factors, bias, and the verifiability of measurement. The rule specifically addresses technological advances in oil metering technology since Order 4 was promulgated. It affirmatively allows the use of those technologies that have been shown to be sufficiently reliable and accurate. It also updates the BLM's requirements related to proper measurement, documentation, and recordkeeping. Going forward the final rules establishes a process for the BLM to review, and approve for use, new oil measurement technology and systems.

IV. Procedural Matters

Executive Orders 12866 and 13563, Regulatory Planning and Review

Executive Order (E.O.) 12866 provides that the Office of Information and Regulatory Affairs (OIRA) will review all significant rules. OIRA has determined that this rule is not significant.

E.O. 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. The BLM has developed this rule in a manner consistent with these requirements.

Regulatory Flexibility Act

The BLM certifies that this final rule will not have a significant economic effect on a substantial number of small entities as defined under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). The Small Business Administration (SBA) has developed size standards to carry out the purposes of the Small Business Act and those size standards can be found at 13 CFR 121.201. The Small Business Act applies to oil and gas extraction firms with fewer than 1,250 employees, oil and gas drilling firms with fewer than 1,000 employees, and firms providing oil and gas support activities with annual receipts of no more than $38.5 million. These small entities must be considered as being at ''arm's length'' from the control of any parent companies.

Of the 6,460 domestic firms involved in onshore oil and gas extraction in 2013, U.S. Census data show that 99 percent (or 6,370) had fewer than 500 employees, which means that nearly all U.S. firms involved in oil and gas extraction in 2013 fell within the SBA's size standard of fewer than 1,250 employees. Of the 2,097 firms participating in oil and gas drilling activities in 2013, U.S. Census data show that 2,044 had fewer than 500 employees, which means that nearly all U.S. firms involved in oil and gas support activities in 2013 fell within the SBA's size standard of fewer than 1,000 employees. There were another 8,877 firms involved in drilling and other support functions in 2012. Of the firms providing support functions, 96 percent (8,561) had annual net receipts of no more than $35 million, with a greater number below the SBA's $38.5 million threshold.

Based on this national data, the preponderance of firms involved in developing oil and gas resources are small entities as defined by the SBA. As such, it appears a number of small entities potentially could be affected by this rule. Using the best available data, the BLM estimates there are approximately 3,700 lessees/operators conducting oil operations on Federal and Indian lands that could be affected by this rule.

On an ongoing basis, we estimate the changes to the LACT meter proving frequency requirements based on volume throughput will increase the regulated community's total annual costs by $67,650. This amount corresponds to the cost of an estimated 123 additional annual provings per year at 28 LACT systems on 19 leases, CAs, or PAs flowing between 31,250 bbl/month/meter and 100,000 bbl/month/meter. This includes 75 additional provings ($41,250 in cost) for 22 LACT systems on 15 leases, CAs, or PAs flowing at least 31,250 bbl/month/meter and below 75,000 bbl/month/meter, and 48 additional provings ($26,400 in cost) for six LACT systems on four leases, CA, or PA's flowing at least 75,000 bbl/month/meter and below 100,000 bbl/month/meter. Currently, LACT systems for both of these groups of systems would be proven monthly for LACTs measuring 100,000 bbl/month or greater, or once every 3 months (four times per year). Under the new rule, meters at the first group of LACT systems (31,250 bbl/month/meter up to 75,000 bbl/month/meter) would be proven every 75,000 bbl, or from 5 to 11 times per year, while meters in the second group of LACT systems (75,000 bbl/month/meter up to 100,000 bbl/month/meter) would be proven monthly, or 12 times each year. There would be no change in proving frequency for properties producing at or above 100,000 bbl/month/meter (one proving per month, or 12 per year) or below 31,250 bbl/month/meter (one proving per quarter, or four per year).

In addition, there will be a one-time cost to retrofit an estimated 20 percent of existing LACT systems of about $1.9 million, or a one-time average cost of about $6,500 for each of an estimated approximately 296 existing LACT systems. This amounts to an average one-time cost of $519 for each of the approximately 3,700 lessees/operators conducting oil production operations on Federal or Indian leases. The requirement for operators to conduct tank strappings to submit revised calibration tables to the BLM will have an annual cost to operators of $4.0 million per year (approximately $1,080 per entity), plus an additional $0.2 million in industry paperwork costs for submitting these tables, and $0.2 million in additional costs to the BLM to process these paperwork submissions. When adding the additional cost of hourly recordkeeping and non-hourly provisions in the final rule, the BLM estimates that the rule will have a total impact of $3.3 million in one-time costs and $4.6 million in annual costs. When the one-time costs are annualized for the first 3 years following the enactment of the final rule, and combined with annual costs for these years, the BLM estimates a total annualized cost of $5.7 million per year, or $1,540 per entity per year, for years 1–3 after the final rule's effective date. After year three, costs will equal the estimated annual cost of $4.6 million, or $1,240 per entity per year. All of the provisions apply to entities regardless of size. However, entities with the greatest activity likely will experience the greatest increase in compliance costs.

Based on the available information, we conclude that the final rule will not have a significant impact on a substantial number of small entities. The final rule will cost each entity an average of less than $2,000 per year, which will impact expected annual operator net income by less than 0.01 percent, as described in the Regulatory Impact Analysis for this rule. Therefore, a final Regulatory Flexibility Analysis is not required, and a Small Entity Compliance Guide is not required.

Small Business Regulatory Enforcement Fairness Act

This final rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule will not have an annual effect on the economy of $100 million or more. As explained under the preamble discussion concerning E.O. 12866, Regulatory Planning and Review, changes to oil measurement under this final rule relative to the existing requirements of Order 4 will increase the cost associated with the development and production of crude oil resources under Federal and Indian oil and gas leases by about $4.8 million annually. Of this amount, about $3.9 million/year will be borne by industry, and $0.9 million/year by the BLM. There will also be a one-time cost of about $1.9 million to retrofit an estimated 20 percent of existing LACT systems, borne entirely by industry.

Based on the cost figures above, the estimated annual increased cost to the estimated 3,700 lessees/operators conducting oil production operations on Federal or Indian leases for implementing these changes is about $1,055 per year, and a one-time average cost of about $520 per entity.

This final rule:

- Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, tribal, or local government agencies, or geographic regions; and
- Will not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

Unfunded Mandates Reform Act

In accordance with the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*), the BLM finds that:

- This final rule will not ''significantly or uniquely'' affect small governments. A Small Government Agency Plan is unnecessary.

• This final rule will not produce a Federal mandate of $100 million or greater in any single year.

The final rule is not a ''significant regulatory action'' as it will not require anything of any non-Federal governmental entity.

Executive Order 12630, Governmental Actions and Interference With Constitutionally Protected Property Rights (Takings)

Under E.O. 12630, the final rule would not have significant takings implications. A takings implication assessment is not required. This final rule will establish the minimum standards for accurate measurement and proper reporting of oil produced from Federal and Indian leases, unit PAs, and CAs, by providing a system for production accountability by operators and lessees. All such actions are subject to lease terms that expressly require that subsequent lease activities be conducted in compliance with applicable Federal laws and regulations. The final rule conforms to the terms of those Federal leases and applicable statutes, and as such the final rule is not a governmental action capable of interfering with constitutionally protected property rights. Therefore, the final rule will not cause a taking of private property and does not require further discussion of takings implications under this E.O.

Executive Order 13132, Federalism

In accordance with E.O. 13132, the BLM finds that the final rule will not have significant Federalism effects. A Federalism assessment is not required. This final rule will not change the role of or shift responsibilities among Federal, State, and local governmental entities. It does not relate to the structure and role of the States and will not have direct, substantive, or significant effects on States.

Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Under Executive order 13175, the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951), and 512 Departmental Manual 2, the BLM evaluated possible effects of the final rule on federally recognized Indian tribes. The BLM approves proposed operations on all Indian (except Osage Tribe) onshore oil and gas leases. Therefore, the final rule has the potential to affect Indian tribes. In conformance with the Secretary's policy on tribal consultation, the BLM held tribal consultation meetings to which more than 175 tribal entities were invited, both before the rule was proposed and during the public comment period on the proposed rule. The consultations were held in:

Pre-Publication Meetings

• Tulsa, Oklahoma on July 11, 2011;
• Farmington, New Mexico on July 13, 2011; and
• Billings, Montana on August 24, 2011.
• Tribal workshop and webcast in Washington, DC on April 24, 2013.

Post-Publication Meetings

• The BLM hosted a webinar to discuss the requirements of the proposed rule and solicit feedback from affected tribes on November 19, 2015; and
• In-person meetings were held in:
  ○ Durango Colorado, on December 1, 2015;
  ○ Oklahoma City, Oklahoma, on December 3, 2015; and
  ○ Dickinson, North Dakota, on December 8, 2015.

The BLM also met with interested tribes on a one-on-one basis, if requested to address questions on the proposed rule prior to the publication of the final rule. In each instance, the purpose of these meetings was to solicit feedback and comments from the tribes. The primary concerns expressed by tribes related to the subordination of tribal laws, rules, and regulations by the proposed rule; tribal representation on the Department's Gas and Oil Measurement Team; and the BLM's Inspection and Enforcement program's ability to enforce the terms of this rule. In general, the tribes, as royalty recipients, expressed support for the goals of the rulemaking, namely accurate measurement. With respect to tribal representation on the Department's Gas and Oil Measurement Team, it should be noted that the team is internal to BLM. That said, the BLM will continue to consult with tribes on measurement issues that impact them and their resources. None of the tribal comments received were directed specifically at this rule's oil measurement requirements, and therefore no changes were made as a result of these comments. While the BLM will continue to address these concerns, none of the concerns affect the substance of the proposed rule.

Executive Order 12988, Civil Justice Reform

Under E.O. 12988, the Office of the Solicitor has determined that the final rule will not unduly burden the judicial system and meets the requirements of Sections 3(a) and 3(b)(2) of the E.O. The Office of the Solicitor has reviewed the final rule to eliminate drafting errors and ambiguity. It has been written to minimize litigation, provide clear legal standards for affected conduct rather than general standards, and promote simplification and burden reduction.

Executive Order 13352, Facilitation of Cooperative Conservation

Under E.O. 13352, the BLM has determined that this final rule will not impede cooperative conservation and will take appropriate account of and consider the interests of persons with ownership or other legally recognized interests in land or other natural resources. This rulemaking process involved Federal, tribal, State, and local governments, private for-profit and nonprofit institutions, other nongovernmental entities and individuals in the decision-making via the public comment process. That process provides that the programs, projects, and activities are consistent with protecting public health and safety.

Paperwork Reduction Act

The Paperwork Reduction Act (PRA) (44 U.S.C. 3501–3521) provides that an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. Collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency. See 44 U.S.C. 3502(3); 5 CFR 1320.3(c) and (k).

This rule contains information collection activities that require approval by the OMB under the Paperwork Reduction Act. The BLM included an information collection request in the proposed rule. OMB has approved the information collection for the final rule under control number 1004–0209.

The information collection activities in this rule are described below along with estimates of the annual burdens. Included in the burden estimates are the time for reviewing instruction, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing each component of the proposed information collection.

Summary of Information Collection Activities

Title: Measurement of Oil (43 CFR parts 3160 and 3170).

Forms: None.

OMB Control Number: 1004–0209.

Description of Respondents: Oil and gas operators.

Abstract: This final rule replaces Onshore Oil and Gas Order Number 4, Measurement of Oil (Order 4) with new regulations that will be codified at 43 CFR parts 3160 and 3170. This rule establishes minimum standards for the measurement of oil produced from Federal and Indian (except Osage Tribe) leases to ensure accurate measurement and accounting. It also updates the minimum standards for oil measurement to reflect the considerable changes in technology and industry practices that have occurred since 1989, when Order 4 was issued.

Frequency of Collection: On occasion.

Obligation to Respond: Required to obtain or retain benefits.

Estimated Annual Responses: 11,707.

Estimated One-Time Responses: 35.

Estimated Annual Reporting and Recordkeeping "Hour" Burden: 3,284.

Estimated One-Time Reporting and Recordkeeping "Hour" Burden: 2,600.

Discussion of Information Collection Activities

The information collection activities in the final rule are discussed below.

Request for Exception to Uncertainty Requirements (43 CFR 3174.4(a)(2))

The final rule, at 43 CFR 3174.4(a), requires each FMP to achieve certain overall uncertainty levels. An operator may seek an exception to the prescribed uncertainty levels by submitting a request to a BLM State Director. The operator must show that meeting the required uncertainly level would involve extraordinary cost or unacceptable adverse environmental effects. The State Director may grant such a request only with written concurrence from the PMT (prepared in coordination with the Deputy Director). This provision enables the BLM to determine whether or not it is reasonable to grant an exception to uncertainty requirements.

Tank Calibration Tables (43 CFR 3174.5(c)(3))

Section 3174.5(c)(3) requires submission of tank calibration tables to the BLM within 30 days after calibration. This provision ensures that BLM personnel will have the latest charts when conducting inspections or audits.

Approval of Automatic Tank Gauging (ATG) Equipment (43 CFR 3174.6(b)(5)(ii)(A)); and Log of ATG Verification (43 CFR 3174.6(b)(5)(ii)(C))

The procedures for oil measurement by tank gauging must comply with the requirements outlined in 43 CFR 3174.6. Beginning on January 17, 2019, only the specific makes and models of ATG that are identified and described at the BLM Web site (*www.blm.gov*) are approved for use.

If an operator chooses to use a particular make or model of ATG equipment, the operator (or the manufacturer of the ATG equipment) must seek and obtain BLM approval of the particular make and model of that equipment by submitting a request to the PMT, consisting of a panel of BLM employees who are oil and gas measurement experts. The submission must describe the test data used to develop performance specifications. After reviewing the test data, the PMT will recommend whether or not to approve the ATG equipment. This information collection activity enables the BLM to consider approving new technologies not yet addressed in its regulations.

The operator must inspect its ATG equipment and verify its accuracy at least once a month, or prior to sales, whichever is later. In addition, the BLM may request inspection and verification at any time.

If the operator finds ATG equipment to be out of tolerance, the operator must calibrate the equipment prior to sales, and must maintain a log of field verifications. That operator must make the log available to the BLM 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 equipment was field-calibrated.

If the ATG equipment was field-calibrated, the as-left manual gauge readings and as-left ATG readings must be recorded. This information collection activity enables the BLM to ensure the accuracy of tank gauging by ATG systems.

Notification of LACT System Failure (43 CFR 3174.7(e)(1))

Section 3174.7(e)(1) requires the operator to notify the BLM within 72 hours of any LACT system failures or equipment malfunctions which may have resulted in measurement error. As defined at proposed § 3174.1, a LACT system consists of components designed to provide for the unattended custody transfer of oil produced from a lease, unit PA, or Communitized Area (CA) 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. This information collection requirement enables the BLM to verify that operators account for all oil volumes.

Approval of a Positive Displacement (PD) Meter (43 CFR 3174.8(a)(1)); and Approval of a Coriolis Meter (43 CFR 3174.9(b))

Section 3174.8(a)(1) requires each custody transfer meter to be a PD meter or a Coriolis meter. A PD meter measures liquid by constantly and mechanically isolating flowing liquid into segments of known volume. A Coriolis meter measures liquid via the interaction between a flowing fluid and oscillation of tubes. Beginning on January 17, 2019, only the specific make, models, and sizes of PD meters and Coriolis meters and associated software that are identified and described at *www.blm.gov* are approved for use.

If an operator chooses to use a particular make or model of PD meter or Coriolis meter, the operator (or the manufacturer of the meter) must seek and obtain BLM approval of that particular make and model by submitting a request to the PMT. The submission must describe the test data used to develop performance specifications. After reviewing the test data, the PMT will recommend whether or not to approve the meter. This information collection activity enables the BLM to consider approving new technologies not yet addressed in its regulations.

Coriolis Meter Specification and Zero Verification Procedure (43 CFR 3174.10(b)(2) and (d)); Zero Verification Log (43 CFR 3174.10(b)(2) and (e)(4)); and Audit Trail Requirements for Coriolis Measurement System (CMS) (43 CFR 3174.10(b)(2) and (f))

Section 3174.10(b)(2) requires the operator to submit Coriolis meter specifications to the BLM upon request. The meter specification of a Coriolis meter must clearly identify the make and model of the Coriolis meter to which they apply and must include the following:

- The reference accuracy for both mass flow rate and density, stated in either percent of reading, percent of full scale, or units of measure;
- The effect of changes in temperature and pressure on both mass flow and fluid density readings;
- The effect of flow rate on density readings;
- The stability of the zero reading for volumetric flow rate;
- Design limits for flow rate and pressure; and

• Pressure drop through the meter as a function of flow rate and fluid viscosity.

Section 3174.10(d) requires the operator to provide the BLM with a copy of the zero value verification procedure upon request.

Section 3174.10(e)(4) requires the operator to maintain a log 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 to the BLM upon request.

Section 3174.10(f) requires the operator to record and retain, and submit to the BLM upon request, the following information:

• Quantity transaction record (QTR) in accordance with the requirements for a measurement ticket (at 43 CFR 3174.12(b));
• Configuration log that contains and identifies all constant flow parameters used in generating the QTR;
• Event log of sufficient capacity to record all events such that the operator can retain the information under the recordkeeping requirements of 43 CFR 3170.7; and
• Alarm log that records the type and duration of any of the following alarm conditions:
  ○ Density deviations from acceptable parameters; and
  ○ Instances in which the flow rate exceeded the manufacturer's maximum recommended flow rate or were below the manufacturer's minimum recommended flow rate.

These information collection activities will assist the BLM in ensuring real-time, on-line measurement of oil.

Meter Proving and Volume Adjustments Notification (43 CFR 3174.11(i)(1)); and Meter Proving Reports (43 CFR 3174.11(i)(3))

Section 3174.11 specifies the minimum requirements for conducting volumetric meter proving for all FMP meters. Meter proving verifies the accuracy of a meter.

Under 43 CFR 3174.11(i)(1), an operator must report to the BLM all meter-proving and volume adjustments after any LACT system or CMS malfunction. The operator must use the appropriate form in API 12.2.3 or API 5.6 (both incorporated by reference at 43 CFR 3174.3), or use a similar format showing the same information as the API form, provided that the calculation of meter factors maintains the proper calculation sequence and rounding.

In addition, a meter-proving report must show the:

• Unique meter ID number;
• Lease number, CA number, or unit PA number;
• The temperature from the test thermometer and the temperature from the temperature averager or temperature transducer;
• 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;
• For density verification (if applicable), the instantaneous flowing density (as determined by Coriolis meter), and the independent density measurement, as compared under 43 CFR 3174.(h); and
• The "as left" fluid flow rate and fluid pressure, if the back pressure valve is adjusted after proving as described in 43 CFR 3174.11(c)(9).

Under § 3174.11(i)(3), the operator must submit the meter-proving report to the BLM no later than 14 days after the meter proving. The proving report may be either in a hard copy or electronic format.

These information collection activities will assist in ensuring the accuracy of meters.

Tank Gauging Run Tickets (43 CFR 3174.12(a)); and LACT or CMS Run Tickets (43 CFR 3174.12(b))

A run ticket is the evidence of receipt or delivery of oil issued by a pipeline, other carrier, or purchaser. The amount of oil transferred from storage is recorded on a run ticket. The amount of payment for oil is based upon information contained in the run ticket.

Tank gauging (43 CFR 3174.12(a))—After oil is measured by tank gauging, the operator, purchaser, or transporter, as appropriate, must complete a uniquely numbered measurement ticket, in either paper or electronic format, with the following information:

• Lease, unit, or CA number;
• Unique tank number and nominal tank capacity;
• Opening and closing dates and times;
• Opening and closing gauges and observed temperatures in °F;
• Observed volume for opening and closing gauge;
• Total gross standard volume removed from the tank;
• Observed API oil gravity and temperature in °F;
• API oil gravity at 60 °F;
• S&W percent;
• Unique number of each seal removed and installed;
• Name of the individual performing the manual tank gauging; and
• Name of the operator.

LACT or CMS (43 CFR 3174.12(b))—The operator, purchaser, or transporter, as appropriate, must complete a uniquely numbered measurement ticket, in either paper or electronic format, at the beginning of every month, and (unless a flow computer is being used in accordance with 43 CFR 3174.10) before conducting proving operations on a LACT system. The following information is required:

• Lease, unit, or CA number;
• Unique meter ID number;
• Opening and closing dates;
• Opening and closing totalizer readings of the indicated volume;
• Meter factor, indicating if it is a composite meter factor;
• Total gross standard volume removed through the LACT system or CMS;
• API oil gravity;
• The average temperature in °F;
• The average flowing pressure in psig;
• S&W percent;
• Unique number of each seal removed and installed;
• Name of the purchaser's representative; and
• Name of the operator.

Request To Use Alternate Oil Measurement System (43 CFR 3174.13)

Section 3174.13 requires prior BLM approval for any method of oil measurement other than manual tank gauging, LACT system, or CMS at an FMP. Any operator requesting approval to use alternate oil measurement equipment 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 measurement equipment would meet or exceed the objectives of the applicable minimum requirements at 43 CFR subpart 3174 and would not affect royalty income or production accountability.

The PMT will review and make recommendations in response to requests to use alternate oil-measurement equipment. This information collection activity enables the BLM to consider approving new technologies not yet addressed in its regulations.

Approval for Slop or Waste Oil (43 CFR 3174.14)

When production cannot be measured due to spillage or leakage, the amount of production must be determined by using any method the BLM approves or prescribes. This category of production includes, but is not limited to, oil that is classified as slop oil or waste oil.

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

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

The following table itemizes the estimated hour burdens for this rule:

ESTIMATED HOUR BURDENS

Type of response A.	Number of responses B.	Hours per response C.	Total hours D.
Request for Exception to Uncertainty Requirements—43 CFR 3174.4(a)(2)—One-Time	5	40	200
Request for Exception to Uncertainty Requirements—43 CFR 3174.4(a)(2)—Annual	2	40	80
Documentation of Tank Calibration Table Strapping—43 CFR 3174.5(c)(3)—Annual	10,000	.25	2,500
Documentation of Testing for Approval of Automatic Tank Gauging (ATG) Equipment—43 CFR 3174.6(b)(5)(ii)(A)—One-Time	5	80	400
Documentation of Testing for Approval of Automatic Tank Gauging (ATG) Equipment—43 CFR 3174.6(b)(5)(ii)(A)—Annual	1	80	80
Log of ATG Verification—43 CFR 3174.6(b)(5)(ii)(C)—Annual	18	0.1	1.8
Notification of LACT System Failure—43 CFR 3174.7(e)(1)—Annual	100	0.25	25
Documentation of Testing for Approval of a Positive Displacement (PD) Meter—43 CFR 3174.8(a)(1)—One-Time	10	80	800
Documentation of Testing for Approval of a Positive Displacement (PD) Meter—43 CFR 3174.8(a)(1)—Annual	1	80	80
Documentation of Testing for Approval of a Coriolis Meter 43 CFR 3174.9(b)—One Time	10	80	800
Documentation of Testing for Approval of a Coriolis Meter 43 CFR 3174.9(b)—Annual	1	80	80
Documentation of Zero Verification Procedure—43 CFR 3174.10(b)(2) and (d)—Annual	100	0.1	10
Zero Verification Log—43 CFR 3174.10(b)(2) and (e)(4)—Annual	100	0.1	10
Audit Trail Requirements for Coriolis Measurement System (CMS)—43 CFR 3174.10(b)(2) and (f)—Annual	500	0.25	125
Onsite Data Display Requirements—43 CFR 3174.10(e)—Annual	500	0.1	50
Meter Prover Calibration Documentation—43 CFR 3174.11(b)—Annual	150	0.5	75
Meter Proving and Volume Adjustments Notification—43 CFR 3174.11(i)(1)—Annual	60	0.1	6
Meter Proving Reports—43 CFR 3174.11(i)(3)—Annual	123	0.25	31
Request to Use Alternate Oil Measurement System—43 CFR 3174.13—One Time	5	80	400
Request to Use Alternate Oil Measurement System—43 CFR 3174.13—Annual	1	80	80
Approval for Slop or Waste Oil—43 CFR 3174.14—Annual	50	1	50
Total Annual Costs	11,707		3,284
Total One-Time Costs	35		2,600

National Environmental Policy Act (NEPA)

The BLM prepared an environmental assessment (EA), a Finding of No Significant Impact (FONSI), and a Decision Record (DR) that conclude that the final rule would not constitute a major Federal action significantly affecting the quality of the human environment under NEPA, 42 U.S.C. 4332(2)(C). Therefore, a detailed environmental impact statement (EIS) under NEPA is not required. A copy of the EA, FONSI, and DR are available for review and on file in the BLM Administrative Record at the location specified in the **ADDRESSES** section.

As explained in the EA, FONSI, and DR, the final rule would not have a significant effect on the human environment because, for the most part, its requirements involve changes that are of an administrative, technical, or procedural nature that apply to the BLM's and the lessee's or operator's administrative processes. For example, the rule allows operators to use a CMS or an ATG/hybrid tank measurement system without receiving a variance from the BLM as they must do now. The final rule also adopts a process and criteria that will allow for the PMT to review any new measurement system or method approval requests submitted to the BLM.

Overall these changes will enhance the agency's ability to account for the oil and gas produced from Federal and Indian lands, but should have minimal to no impact on the environment. Some of these standards, such as the requirement that operators replace their automatic temperature/gravity compensators with temperature averaging devices, may result in increased human presence and traffic on existing disturbed surfaces, but these activities are expected to have a negligible impact on the quality of the human environment, as discussed in the final EA.

A draft of the EA was shared with the public during the public comment period on the proposed rule. As part of that process, the BLM received comments on the EA. Commenters questioned the BLM's level of NEPA documentation, whether or not the BLM had met the ''hard look'' test of describing the environmental consequences of the proposed action, and the BLM's ability to reach a FONSI based on the level of analysis. One commenter requested a complete NEPA revision with formal scoping of the EA and a meaningful socioeconomic analysis. Many commenters questioned the use of three separate EAs to disclose impacts of Order 3, Order 4, and Order 5, stating that the Council on Environmental Quality (CEQ) regulations require connected actions to be evaluated in a single document. These commenters suggested a single EIS to address all three rules.

CEQ's NEPA regulations at 40 CFR 1508.18 identify new or revised agency rules and regulations as an example of a Federal action. Drafting new agency regulations that ''are of an administrative . . . technical, or procedural nature'' is categorically excluded from NEPA review pursuant to 43 CFR 46.210(i). The BLM nevertheless chose to complete a more robust level of NEPA documentation in the form of an EA. By preparing a separate EA for new subpart 3173, 3174, and 3175 regulations, the BLM was able to disclose the potential environmental effects of the Federal agency decisions on each of the regulations. Clearly, the BLM's level of analysis was more thorough than the categorical exclusion documentation required by NEPA. Additionally, a thorough socioeconomic analysis was completed in the BLM's regulatory impact analysis of the proposed rule, which was referenced in the EA.

Other commenters stated the BLM did not adequately address potential surface impacts to private land, minimized environmental surface impacts, did not address a reasonable range of alternatives, and did not adequately describe the Affected Environment. The BLM anticipates that in the majority of cases, operators will use existing surface disturbances such as existing well pad locations in connection with activities undertaken in compliance with the final rule, which will minimize new surface construction and surface impacts. Any new facilities will likely be constructed on a lease, relocated to an existing facility, or retrofitted to an existing facility. Similarly, the codification of BLM regulations does not hinder or prevent development of private minerals. The likelihood of impacts to private surface is low. In the rare instance that new pipelines or other facilities must be developed on private surface to comply with this rule, BLM authorization for activities on split estate would include site-specific NEPA documentation, with appropriate project-level mitigation. The BLM's obligation under NEPA is to analyze alternatives that would meet the Bureau's purpose and need and allow for a reasoned choice to be made. As described in the EA, a number of alternatives were considered, but eliminated from detailed study because they did not meet the purpose and need. Discussion of the affected environment should only contain data and analysis commensurate in detail with the importance of the impacts, which the BLM anticipates to be minimal.

The EA, FONSI, and DR were updated to address these comments, but the updates did not change the BLM's overall analysis of the potential environmental impacts of the rule.

Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Although this rule amends the BLM's oil production regulations, it will not have a substantial direct effect on the nation's energy supply, distribution, or use, including a shortfall in supply or price increases. Changes in this rule strengthen the BLM's production accountability requirements for operators holding Federal and Indian oil leases. As discussed previously, among other things, this rule establishes objective measurement performance standards, updates recordkeeping requirements, and establishes uniform national requirements for operators who wish to use CMSs or ATG systems. As explained in detail in the BLM's regulatory impact analysis, all of these changes will increase the regulated community's annual costs by about $3.9 million, or about $1,055 per entity per year.

The BLM expects that the rule will not result in a net change in the quantity of oil that is produced from Federal and Indian leases.

Information Quality Act

In developing this rule, the BLM did not conduct or use a study, experiment, or survey requiring peer review under the Information Quality Act (Pub. L. 106–554, Appendix C Title IV, 515, 114 Stat. 2763A–153).

Authors

The principal authors of this final rule are Mike McLaren, Petroleum Engineer, BLM Pinedale Field Office; Tom Zelenka, Petroleum Engineer, BLM New Mexico State Office; Chris DeVault, I&E Coordinator, BLM Montana State Office; Jeff Prude, Petroleum Engineer, BLM Bakersfield Field Office; and Frank Sanders, Petroleum Engineer, BLM Worland Field Office. The team was assisted by Faith Bremner, Jean Sonneman and Ian Senio, Office of Regulatory Affairs, BLM Washington Office; Michael Ford, Economist, BLM Washington Office; Barbara Sterling, Natural Resource Specialist, BLM Colorado State Office; Bryce Barlan, Senior Policy Analyst, BLM, Washington Office; Michael Wade, BLM Washington Office; Rich Estabrook, BLM Washington Office; Dylan Fuge, Counselor to the Director, BLM Washington Office; Christopher Rhymes, Attorney Advisor, Office of the Solicitor, Department of the Interior; and Geoffrey Heath (now retired).

List of Subjects

43 CFR Part 3160

Administrative practice and procedure, Government contracts, Indians-lands, Mineral royalties, Oil and gas exploration, Penalties, Public lands—mineral resources, Reporting and recordkeeping requirements.

43 CFR Part 3170

Administrative practice and procedure, Immediate assessments, Incorporation by reference, Indians-lands, Mineral royalties, Oil and gas measurement, Public lands—mineral resources.

Dated: October 6, 2016.

Janice M. Schneider,

Assistant Secretary, Land and Minerals Management.

43 CFR Chapter II

For the reasons set out in the preamble, the Bureau of Land Management is amending 43 CFR parts 3160 and 3170 as follows:

PART 3160—ONSHORE OIL AND GAS OPERATIONS

■ 1. The authority citation for part 3160 continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

■ 2. Revise § 3162.7–2 to read as follows:

§ 3162.7–2 Measurement of oil.

All oil removed or sold from a lease, communitized area, or unit participating area must be measured under subpart 3174 of this title. All measurement must be on the lease, communitized area, or unit from which the oil originated and must not be commingled with oil originating from other sources, unless approved by the authorized officer under the provisions of subpart 3173 of this title.

§ 3164.1 [Amended]

■ 3. Amend § 3164.1(b) by removing the fourth entry in the table, Order No. 4, Measurement of Oil.

PART 3170—ONSHORE OIL AND GAS PRODUCTION

■ 4. The authority citation for part 3170 continues to read as follows:

Authority: 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733, and 1740.

■ 5. Add subpart 3174 to part 3170, to read as follows:

Subpart 3174—Measurement of Oil

§ 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 in-line 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
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

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