4310-84P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 3160 and 3170

[17X.LLWO310000.L13100000.PP0000]

RIN 1004-AE17

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

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rule.

SUMMARY: This final rule updates and replaces Onshore Oil and Gas Order No. 5 (Order 5) with a new regulation codified in the Code of Federal Regulations (CFR). Like Order 5, this rule establishes minimum standards for accurate measurement and proper reporting of all gas removed or sold from Federal and Indian (except the Osage Tribe) leases, units, unit participating areas (PAs), and areas subject to communitization agreements (CAs). It provides a system for production accountability by operators, lessees, purchasers, and transporters. This rule establishes overall gas measurement performance standards and includes, among other things, requirements for the hardware and software related to gas metering equipment and reporting and recordkeeping. This rule also identifies certain specific acts of noncompliance that may result in an immediate assessment and provides a process for the Bureau of Land Management (BLM) to consider variances from the requirements of this rule.

DATES: The final rule is effective on [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

FOR FURTHER INFORMATION CONTACT: Richard Estabrook, petroleum engineer, Division of Fluid Minerals, 707-468-4052, or Steven Wells, Division Chief, Division of Fluid Minerals, 202-912-7143, for information regarding the BLM's Fluid Minerals Program. For questions relating 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 1-800-877-8339 to contact the above individual 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 individual. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION:

I. Background and Overview

Under applicable laws, royalties are owed on all production removed or sold from Federal and Indian oil and gas leases. The basis for those royalty payments is the measured volume and quality of the production from those leases. In fiscal year (FY)

2015, onshore Federal oil and gas lease holders sold 180 million barrels of oil,[1] 2.5 trillion cubic feet of natural gas,[2] 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, generating royalties of over $0.6 billion that were all distributed to the applicable tribes and individual allottment owners.

As explained in the preamble for the proposed rule, given the magnitude of this production and the BLM's statutory and management obligations, it is critically important that the BLM ensure that operators accurately measure, report, and account for that production. The final rule helps achieve that objective by updating and replacing Order 5's requirements with respect to the measurement of gas with regulations codified in the CFR that reflect changes in applicable laws, metering technology, and industry standards since Order 5 was first promulgated in 1989.[3]

The basis for this rule is the Secretary of the Interior's authority under various Federal and Indian mineral leasing laws to manage oil and gas operations, which authority has been delegated to the BLM. In implementing that authority, the BLM issued onshore oil and gas operating regulations that are codified at 43 CFR part 3160. The regulations at 43 CFR part 3160, Onshore Oil and Gas Operations, in § 3164.1, provide for the issuance

[1] 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.
[2] This figure includes all processed and unprocessed volumes recovered on-lease, nitrogen, fuel gas, coalbed methane, and any volumes of gas lost due to venting or flaring.
[3] Order 5 has been in effect since March 27, 1989 (see 54 Federal Register (FR) 8100).

of Onshore Oil and Gas Orders to "implement and supplement" the regulations in part 3160.[4] The table in § 3164.1(b) lists the existing Orders. This final rule updates and replaces Order 5 and will be codified in the CFR, primarily in new subpart 3175. Like Order 5, this final rule sets the requirements for the measurement of gas produced or sold from a lease; it does not address other circumstances in which the BLM requires royalty payment, such as for avoidably lost gas (see Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases (NTL-4A), Royalty or Compensation for Oil and Gas Lost, 44 FR 76600 (Dec. 27, 1979); see also 81 FR 6616 (February 8, 2016)).

Consistent with updating and replacing Order 5, this rule also supersedes various statewide NTLs that have been issued from time-to-time to provide additional guidance regarding compliance with the requirements of Order 5, including:

- NM NTL 92-5, January 1, 1992;
- WY NTL 2004-1, April 23, 2004;
- CA NTL 2007-1, April 16, 2007;
- MT NTL 2007-1, May 4, 2007;
- UT NTL 2007-1, August 24, 2007;
- CO NTL 2007-1, December 21, 2007;
- NM NTL 2008-1, January 29, 2008;
- ES NTL 2008-1, September 17, 2008;
- AK NTL 2009-1, July 29, 2009; and

[4] Over the years, the BLM has issued seven Onshore Oil and Gas Orders that have dealt with different aspects of oil and gas production. These Orders were published in the FR, both for public comment and in final form, but they do not appear in the CFR. Although they are not codified in the CFR, all Onshore Orders have been issued consistent with Administrative Procedure Act (APA) notice and comment rulemaking procedures, and therefore have the effect of regulations and apply nationwide to all Federal and Indian (except the Osage Tribe) onshore oil and gas leases.

- CO NTL 2014-01, May 19, 2014.

Although this rule supersedes Order 5 and various statewide NTLs, the existing requirements of Order 5 and those NTLs remain in effect during the phase-in periods – specified in § 3175.60(b) – for the rule's new requirements.

The requirements in this rule help ensure that the Department of the Interior (DOI or the Department) meets it responsibility to collect royalties on gas extracted from Federal onshore and Indian (except the Osage Tribe) leases. The proper measurement of gas is essential to ensure that the American public, as well as Indian tribes and individual allottees, receive the royalties to which they are entitled on oil and gas produced from Federal and Indian leases, respectively.

As explained in the preamble to the proposed rule, these changes were prompted by internal and external concerns about the adequacy of the BLM's existing gas measurement rules. Notably, these concerns were highlighted in several external reviews of the BLM's measurement program by three independent outside entities – the Secretary of the Interior's (Secretary's) Subcommittee on Royalty Management (the Subcommittee) in 2007, the DOI's Office of the Inspector General (OIG) in 2009, and the Government Accountability Office (GAO) in 2010, 2011, 2013, and 2015 – all of which have repeatedly recommended that the BLM evaluate its gas measurement guidance and regulations to ensure that operators are properly accounting for production from Federal and Indian leases and are paying the proper royalties. Specifically, these groups found with respect to gas measurement that the DOI needed to provide Department-wide guidance on measurement technologies and processes not addressed in current regulations, including guidance on the process for approving variances in instances when new technologies or processes are developed that are not yet addressed by existing rules. As explained in the Section-by-Section analysis, the provisions of this final rule respond to these recommendations.

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 guidance regarding production accountability and measurement is "unconsolidated, outdated, and sometimes insufficient" (Subcommittee report, p. 30). The Subcommittee report found that this results in inconsistent and outmoded approaches to production accountability and measurement tasks and, ultimately, potential inaccuracies in royalty collections. The final rule in part results from the recommendations contained in the Subcommittee's report, which was issued on December 17, 2007.

Specifically, the Subcommittee report expressed concern that the applicable "BLM policy and guidance is outdated" and "some policy memoranda have expired" (Subcommittee report, p. 31). It also noted that "BLM policy and guidance have not been consolidated in a single document or publication," which has led to the "BLM's 31 oil and gas field offices using varying policy and guidance" (id.). For example, "some BLM State Offices have issued their own 'Notices to Lessees' for oil and gas operations" (id.). While the Subcommittee recognized that such NTLs may have a positive effect on some

[5] The Subcommittee was commissioned to report to the Royalty Policy Committee, which was chartered under the Federal Advisory Committee Act (FACA) 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.

oil and gas field operations, it also observed that they necessarily "lack a national perspective and may introduce inconsistencies among State (Offices)" (id.).

Of the 110 recommendations made in the 2007 Subcommittee report, 12 recommendations relate directly to improving the measurement and reporting of natural gas volume and heating value. For example, the Subcommittee paid particular attention to the measurement and reporting of heating value because it has a direct impact on royalties ultimately collected as heating value establishes the energy content of a particular volume of gas, a key component of its market value. Heating value is as important to calculating royalties due as measured volume. Currently, Order 5 requires only yearly measurement of natural gas heating value and there are no BLM standards for how operators should measure heating value, where they should measure it, how they should analyze it, or on what basis they should report it. The requirements in subpart 3175 of this final rule establish these standards.

This rule also addresses findings and recommendations made in two GAO reports and one OIG report: (1) 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 Report 10-313); (2) GAO Report to Congressional Requesters, Oil and Gas Resources, Interior's Production Verification Efforts and Royalty Data Have Improved, But Further Actions Needed, GAO-15-39 (GAO Report 15-39); and (3) OIG Report, Bureau of Land Management's Oil and Gas Inspection and Enforcement Program (CR-EV-0001-2009) (OIG Report).

Consistent with the Subcommittee's findings, 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, its policies for tracking where and how oil and gas are measured are not consistent and effective (GAO Report 10-313, 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 the DOI 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 OIG Report, 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 Report 15-39, p. 16). Among its recommendations were that the Secretary direct the BLM to "meet its established timeframe for issuing final regulations for gas measurement" (ibid., p. 32).

In total, the GAO made 19 recommendations to improve the BLM's ability to ensure that oil and gas produced from Federal and Indian lands are accurately measured and properly reported (GAO Report 10-313), a number of which relate to gas measurement. For example, the report recommends that the BLM establish goals that would allow it to witness gas sample collections; however, it recognized that the BLM must first establish gas sampling standards as a basis for inspection and enforcement actions. This final rule establishes those standards. Similarly, the 2015 GAO report recommends, among other things, that the BLM issue new regulations pertaining to gas measurement, which this rule accomplishes.

It should also be noted that the GAO's recommendations regarding gas measurement are also one of the bases for the GAO's inclusion of the Department's oil and gas program on the GAO's High Risk List in 2011 (GAO-11-278) and for its continuing to keep the program on the list in the 2013 and 2015 updates (GAO-13-283 (2013) and GAO-15-290 (2015)). Specifically, the GAO concluded with respect to the High Risk List that inclusion of the BLM's oil and gas program is justified because, among other things, the program's existing policies and regulations do not provide "reasonable assurance that … gas produced from federal leases is accurately measured and that the public is getting an appropriate share of oil and gas revenues" (GAO-11-278, p. 38).

In addition to these external reports and assessments, the provisions of this rule are also based on the BLM's own internal assessment of the adequacy of the existing requirements of Order 5. For example, because many improvements in technology and industry standards have occurred since Order 5 was issued, the BLM has had to develop a number of statewide NTLs and/or approve a number of site-specific variances. This final rule addresses these issues and supersedes the statewide NTLs.

The following summarizes and briefly explains the most significant provisions in this final rule. Each of these is discussed more fully in the Section-by-Section analysis below. For that reason, references to specific section and paragraph numbers are omitted in the body of this summary discussion.

1. Determining and Reporting Heating Value and Relative Density (§§ 3175.110 through 3175.126)

The most significant requirements of the final rule are related to determining and reporting the heating value and relative density of all gas produced. Royalties on gas are calculated by multiplying the volume of the gas removed or sold from the lease (generally expressed in thousands of standard cubic feet (Mcf)) by the heating value of the gas in British thermal units (Btu) per unit volume, the value of the gas (expressed in dollars per million Btu (MMBtu)), and the fixed royalty rate. Therefore, a 10 percent error in the reported heating value would result in the same error in royalty as a 10 percent error in volume measurement. Relative density, which is a measure of the average mass of the molecules flowing through the meter, is used in the calculation of flow rate and volume. Because the flow equation uses the square root of relative density, a 10 percent error in relative density would only result in a 5 percent error in the volume calculation. Both heating value and relative density are determined from the same gas sample.

Currently, Order 5 requires a determination of heating value only once per year. Federal and Indian onshore gas producers can then use that value in the royalty calculations for an entire year. There are currently no requirements in Order 5 for determining relative density. Existing regulations do not have standards for how gas samples used in determining heating value and relative density should be taken and analyzed to avoid biasing the results. In addition, existing regulations do not prescribe when and how operators should report the results to the BLM.

In response to a Subcommittee recommendation that the BLM determine the potential heating-value variability of produced natural gas and estimate its implications for royalty payments, the BLM conducted a study of 180 gas facility measurement points (FMPs) that found significant sample-to-sample variability in heating value and relative density. The “BLM Gas Variability Study Final Report,” dated May 21, 2010, used 1,895 gas analyses gathered from 65 formations. In one example, the study found that heating values measured from samples taken at a gas meter in the Anderson Coal formation in the Powder River Basin varied ±31.41 percent, while relative density varied ±19.98 percent. In multiple samples collected at another gas meter in the same formation, heating values varied by only ±2.58 percent, while relative density varied by ±3.53 percent (p. 25). Overall, the uncertainty (statistical range of error that indicates the risk of measurement error) in heating value and relative density in this study was ±5.09 percent, which, across the board, could amount to ±$127 million in royalties based on 2008 total onshore Federal and Indian royalty payments of about $2.5 billion (p. 16).

The study concluded that heating value variability is unique to each gas meter and is not related to reservoir type, production type, age of the well, richness of the gas, flowing temperature, flow rate, or several other factors that were included in the study (p. 17). The study also concluded that more frequent sampling increases the accuracy of average annual heating value determinations (p. 11).

This rule strengthens the BLM’s regulations on measuring heating value and relative density by requiring operators to sample all meters more frequently than required under Order 5, except very-low-volume meters (measuring 35 Mcf/day or less), for which annual sampling remains sufficient. Low-volume FMPs (measuring more than 35

Mcf/day, but less than or equal to 200 Mcf/day) must be sampled every 6 months; high-volume FMPs (measuring more than 200 Mcf/day, but less than or equal to 1,000 Mcf/day) must initially be sampled every 3 months; very-high-volume FMPs (measuring more than 1,000 Mcf/day) must initially be sampled every month. In developing this rule, the BLM realized that a fixed sampling frequency may not achieve a consistent level of uncertainty in heating value for high-volume and very-high-volume meters. For example, a 3-month sampling frequency may not adequately reduce average annual heating value uncertainty in a meter which has exhibited a high degree of variability in the past. On the other hand, a 3-month sampling frequency may be excessive for a meter that has very consistent heating values from one sample to the next. If a high- or very-high-volume FMP did not meet these heating-value uncertainty limits, the BLM will adjust the sampling frequency at that FMP until the heating value meets the uncertainty standards. If a very-high-volume FMP continues to exceed the uncertainty standards, the final rule includes a provision that allows the BLM to require the installation of composite samplers or on-line gas chromatographs (GCs), which automatically sample gas at frequent intervals.

The rule also sets new average annual heating value uncertainty standards of ±2 percent for high-volume FMPs and ±1 percent for very-high-volume FMPs. The BLM established these uncertainty thresholds by determining the uncertainty at which the cost of compliance equals the risk of royalty underpayment or overpayment.

In addition to prescribing uncertainty standards and more frequent sampling, this rule also improves measurement and reporting of heating values and relative density by setting standards for gas sampling and analysis. These standards specify sampling locations and methods, analysis methods, and the minimum number of components that must be analyzed. The standards also set requirements for how and when operators report the results to the BLM and the Office of Natural Resources Revenue (ONRR), and define the effective date of the heating value and relative density that is determined from the sample.

2. Meter Inspections (§ 3175.80)

This rule requires operators to periodically inspect the insides of meter tubes for pitting, scaling, and the buildup of foreign substances, which could bias measurement. Existing regulations do not address this issue. Under this rule, basic meter tube inspections are required once every 5 years at low-volume FMPs, once every 2 years at high-volume FMPs, and yearly at very-high-volume FMPs. The BLM has the ability to increase this frequency if a basic inspection identifies any issues or if the meter tube operates in adverse conditions, such as with corrosive or erosive gas flow. If the basic inspection indicates the presence of pitting, obstructions, or a buildup of foreign substances, at low-volume FMPs the operator must clean the meter tube of obstructions and foreign substances; at high- and very-high-volume FMPs, the operator must conduct a detailed meter tube inspection. A detailed meter-tube inspection involves removing or disassembling the meter run. Operators must repair or replace meter tubes that no longer meet the requirements in this rule.

3. Meter Verification or Calibration (§§ 3175.92 and 3175.102)

The rule changes routine meter verification or calibration requirements from current requirements under Order 5. Verification frequency is decreased at all very-low-volume FMPs and low-volume FMPs using electronic gas measurement (EGM) systems.

Verification frequency is unchanged from current regulations for low-volume FMPs using mechanical recorders and high- and very-high-volume FMPs. Currently, under Order 5, all meters are required to undergo routine verification every 3 months, regardless of the throughput volume.

The rule restricts the use of mechanical chart recorders to low- and very-low-volume FMPs because the accuracy and performance of mechanical chart recorders is not defined well enough for the BLM to quantify the overall measurement uncertainty. Between 80 and 90 percent of gas meters at Federal onshore and Indian FMPs use EGM systems.

4. Requirements for EGM Systems (§§ 3175.31, 3175.100 through 3175.104 and §§ 3175.130 through 3175.144)

Although industry has used EGM systems for about 30 years, Order 5 does not currently address them. Instead, the BLM has regulated their use through statewide NTLs, which do not address many aspects unique to EGMs, such as volume calculation and data-gathering and retention requirements. This rule includes many of the existing NTL requirements for EGM systems and adds some new requirements relating to onsite information, gauge lines, verification, test equipment, calculations, and information generated and retained by the EGM systems. The rule includes a significant change in those requirements by revising the maximum flow-rate uncertainty that is currently allowed under existing statewide NTLs. Under the NTLs, flow-rate equipment at FMPs that measure more than 100 Mcf/day is required to meet a ±3 percent uncertainty level. The rule maintains that level of uncertainty for high-volume FMPs although the threshold is raised to 200 Mcf/day. Under this rule, equipment at very-high-volume FMPs must comply with a new ±2 percent uncertainty requirement. Flow-rate equipment at FMPs that measure less than 200 Mcf/day is exempt from these uncertainty requirements. The BLM is maintaining this exemption because it believes that compliance costs for these FMPs could cause some operators to shut in their wells instead of making improvements. The BLM believes the royalties lost by such shut-ins would exceed any royalties that might be gained through upgrades at such facilities.

One area that this rule addresses, which is not addressed by existing NTLs, is the accuracy of transducers and flow-computer software used in EGM systems. Transducers send electronic data to flow computers, which use that data, along with other data that are programmed into the flow computers, to calculate volumes and flow rates. Currently, the BLM must accept transducer manufacturers' claimed performance specifications when calculating uncertainty. Neither the American Petroleum Institute (API) nor the Gas Processors Association (GPA) has standards for determining these performance specifications. For this reason, the rule requires operators or manufacturers to "type test" transducers at a qualified testing facility using a standard testing protocol defined in this rule or, for transducers that are already in use at FMPs, submit existing test data to the BLM for review. The purpose of this review is to quantify the uncertainty of the transducers using actual test data, rather than relying on the manufacturer's performance specifications. The BLM will then incorporate the test results into the calculation of overall measurement uncertainty based on each transducer tested. The rule also requires operators or manufacturers to test flow computers and flow-computer software at qualified testing facilities, using a standard testing protocol defined in this rule, to assess the ability of those flow-computers and software versions to accurately calculate flow rate, volume, and other values that are used in the BLM's verification process. Only those flow computers and flow computer software versions that demonstrate the ability to perform these calculations within the tolerances established by the BLM will be allowed for use on Federal and Indian leases.

An integral part of the BLM's evaluation process is the Production Measurement Team (PMT), made up of measurement experts designated by the BLM.[6] The rule requires that the PMT review the results of type testing done on transducers and flow-computer software and make recommendations to the BLM. If approved, the BLM will post the make, model, and range of the transducer or software version on the BLM website as being appropriate for use. The BLM will also use the PMT to evaluate and make recommendations on the use of other new types of equipment, such as flow conditioners and primary devices, new measurement sampling, or analysis methods.

II. Discussion of Final Rule and Comments on the Proposed Rule

A. General Overview of Final Rule

As discussed in the Background and Overview section of this preamble, the provisions of Order 5 have not kept pace with industry standards and practices, statutory requirements, or applicable measurement technology and practices. This final rule updates and replaces those requirements by establishing the minimum standards for accurate measurement and proper reporting of all gas sold from Federal and Indian (except the Osage Tribe) leases, units, unit PAs, and areas subject to CAs, by providing a

[6] The PMT will be distinguished from the DOI's Gas and Oil Measurement Team (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 will not use a dual-agency approval process for the use of new measurement technologies for onshore leases. The BLM anticipates that members of the BLM PMT will participate as a part of the DOI GOMT.

system for production accountability by operators, lessees, purchasers, and transporters. 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 5 appears in the proposed rule at 80 FR 61650 (October 13, 2015).

Proposed Rule	**Final Rule**	**Substantive Changes**
§ 3175.10 – Definitions and acronyms	§ 3175.10 – Definitions and acronyms	The final rule changes the term “marginal-volume FMP” to “very-low-volume” FMP and its range changes from less than or equal to 15 Mcf/day in the proposed rule to less than or equal to 35 Mcf/day in the final rule. The final rule changes the range for low-volume FMPs from 15 Mcf/day to less than 100 Mcf/day in the proposed rule to 35 Mcf/day to less than 200 Mcf/day in the final rule. The final rule changes the range of high-volume FMPs from 100 Mcf/day to less than 1,000 Mcf/day in the proposed rule to 200 Mcf/day to less than 1,000 Mcf/day in the final rule. The final rule changes the averaging period used to determine the flow categories. In the proposed rule, the category would have been calculated over the previous 12 months of the life of the meter, whichever is shorter. The final rule removes the timeframe over which the flow category is calculated, and instead refers to a new definition of “averaging period” that is added to subpart 3170. The final rule includes a definition for “variability” and removes the definition in the proposed rule for “significant digits.”
§ 3175.20 – General requirements	§ 3175.20 – General requirements	None.
§ 3175.30 – Specific performance requirements	§ 3175.31 – Specific performance requirements	The final rule adds a default calculation method for uncertainty of average annual heating value. The method added to the final rule is the same as the one identified in the BLM’s heating value

		variability study that was discussed and relied on in preparing both the proposed and final rules.
§ 3175.31 – Incorporation by reference	§ 3175.30 – Incorporation by reference	The final rule adopts the latest versions of certain API and GPA standards along with an additional GPA standard, and incorporates them by reference into the BLM's oil and gas regulations. The final rule also incorporates older versions of API standards referenced in Order 5 and the Statewide NTLs for electronic flow computers (EFCs).
§ 3175.40 – Measurement equipment approved by standard or make and model	§ 3175.40 – Measurement equipment approved by standard or make and model	None.
§ 3175.41 – Flange-tapped orifice plates	§ 3175.41 – Flange-tapped orifice plates	None.
§ 3175.42 – Chart recorders	§ 3175.42 – Chart recorders	None.
§ 3175.43 – Transducers	§ 3175.43 – Transducers	For transducers in use before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], the final rule allows operators or manufacturers to submit existing test data in lieu of performing the testing protocols in § 3175.130.
§ 3175.44 – Flow computers	§ 3175.44 – Flow computers	The final rule requires operators or manufacturers to submit a description of changes for all new software versions, regardless of whether or not they affect the determination of flow rate, volume, heating value, or auditability. The final rule exempts software versions used at low- and very-low-volume FMPs from the testing provisions of this paragraph, unless the BLM requires otherwise.
§ 3175.45 – Gas chromatographs	§ 3175.45 – Gas chromatographs	None.
§ 3175.46 – Isolating flow conditioners	§ 3175.46 – Isolating flow conditioners	The final rule removes the provision allowing the BLM to require additional flow conditioner testing beyond what API 14.3.2, Annex D requires.
§ 3175.47 –	§ 3175.47 –	The final rule allows either operators or

Differential primary devices other than flange-tapped orifice plates	Differential primary devices other than flange-tapped orifice plates	manufacturers to test differential primary devices. The proposed rule would have required the operator to perform the testing.
§ 3175.48 – Linear measurement devices	§ 3175.48 – Linear measurement devices	The final rule allows the BLM to approve linear measurement devices by make, model, and size.
No section in the proposed rule	§ 3175.49 – Accounting systems	The final rule adds accounting systems to the list of measurement equipment approved by standard or make and model.
§ 3175.60 – Timeframes for compliance	§ 3175.60 – Timeframes for compliance	The final rule delays implementation of provisions in § 3175.120(e) and (f); § 3175.115(b); §§ 3175.43 and 3175.44; and §§ 3175.46 through 3175.49 until January 17, 2019. The final rule also extends the compliance timeframe for very-high-volume FMPs from 6 months in the proposed rule to 1 year.
No section in the proposed rule	§ 3175.61 – Grandfathering	The final rule grandfathers meter tubes existing as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] at low- and high-volume FMPs; however, the meter tubes must still meet the requirements of the American Gas Association (AGA) Report No. 3 (1985). The final rule grandfathers EGM software at very-low-volume FMPs existing prior to [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]; however, it must meet the requirements of AGA Report No. 3 (1985), and NX-19. The final rule grandfathers EGM software at low-volume FMPs existing prior to [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], but it must meet the requirements of API 14.3.3 (1992).
§ 3175.70 – Measurement location	§ 3175.70 – Measurement location	None.
§ 3175.80 – Flange-	§ 3175.80 – Flange-	The final rule exempts very-low-volume

tapped orifice plates (primary devices)	tapped orifice plates (primary devices)	FMPs from orifice plate eccentricity and perpendicularity requirements and requirements for inspecting FMPs measuring production from a new or re-fractured well. The final rule changes the term “visual meter tube inspection” to “basic meter tube inspection,” and sets performance standards for this type of inspection. The final rule only requires a detailed meter tube inspection when it is triggered by a basic meter tube inspection and requires the inspection within 30 days of the basic inspection. If a basic meter tube inspection reveals issues at a low-volume FMP, the final rule only requires the operator to clean the meter tube instead of performing a detailed inspection. The final rule adds re-fracturing to the conditions that trigger inspections for a “new FMP orifice plate inspection.” The final rule allows operators to submit a monthly or quarterly schedule of routine orifice plate inspections in lieu of a 72-hour notice. The final rule deems that the location of a 19-tube-bundle flow straightener installed in accordance with AGA Report No. 3 (1985) complies with API 14.3.2 (2016), if the Beta ratio is less than 0.5. The final rule allows insulation or heat tracing as acceptable methods to achieve the same temperature as the temperature at the orifice plate.
§ 3175.90 – Mechanical recorder (secondary device)	§ 3175.90 – Mechanical recorder (secondary device)	None.
§ 3175.91 – Installation and operation of mechanical recorders	§ 3175.91 – Installation and operation of mechanical recorders	The final rule allows 3/8-inch nominal diameter gauge lines. The final rule does not require gauge lines to be made out of stainless steel and adds a requirement that gauge lines can have no visible sag.
§ 3175.92 – Verification and calibration of mechanical recorders	§ 3175.92 – Verification and calibration of mechanical recorders	The final rule allows operators to submit monthly or quarterly schedules of verifications to the BLM in lieu of a 72-hour notice.

§ 3175.93 – Integration statements	§ 3175.93 – Integration statements	None.
§ 3175.94 – Volume determination	§ 3175.94 – Volume determination	None.
§ 3175.100 – Electronic gas measurement (secondary and tertiary device)	§ 3175.100 – Electronic gas measurement (secondary and tertiary device)	None.
§ 3175.101 – Installation and operation of electronic gas measurement systems	§ 3175.101 – Installation and operation of electronic gas measurement systems	The final rule allows 3/8-inch nominal diameter gauge lines. The final rule does not require gauge lines to be made out of stainless steel and adds a requirement that gauge lines can have no visible sag. The final rule allows operators to display a unique meter identification number in lieu of the FMP number and reduces the number of items that the flow computer has to display from 13 to 8. The final rule allows differential-pressure transducers to exceed their upper calibrated limit for brief periods in plunger lift operations, if approved by the BLM.
§ 3175.102 – Verification and calibration of electronic gas measurement systems	§ 3175.102 – Verification and calibration of electronic gas measurement systems	The final rule only requires the operator to re-zero a differential-pressure transducer if the zero reading under working pressure changes by more than the reference accuracy of the transducer. The final rule defines how close to the normal operating pressure the normal verification point has to be. The final rule adds a provision that requires the operator to replace a transducer if the as-found values are out of tolerance for two consecutive verifications. The final rule allows operators to submit monthly or quarterly schedules of verifications to the BLM in lieu of a 72-hour notice. The final rule requires amended reports if the verification error is 2 percent or 2 Mcf/day, whichever is greater.
§ 3175.103 – Flow rate, volume, and	§ 3175.103 – Flow rate, volume, and	None.

average value calculation	average value calculation	
§ 3175.104 – Logs and records	§ 3175.104 – Logs and records	The final rule specifies the number of decimal places for certain variables on a quantity transaction record (QTR) instead of the number of significant digits. The final rule no longer requires the event log to record the length of a power outage. The final rule only allows accounting systems for reporting to the BLM if the accounting system has been reviewed by the PMT and approved by the BLM.
§ 3175.110 – Gas sampling and analysis	§ 3175.110 – Gas sampling and analysis	None.
§ 3175.111 – General sampling requirements	§ 3175.111 – General sampling requirements	The final rule requires operators to maintain sample system temperature at or above the flowing temperature of the gas or 30°F above the hydrocarbon dew point (HCDP), if the HCDP is calculated.
§ 3175.112 – Sampling probe and tubing	§ 3175.112 – Sampling probe and tubing	The final rule adopts API standards for the sample probe location instead of requiring operators to install it 1–2 times dimension "DL" downstream of the orifice plate. The final rule allows the use of insulation and/or heat tracing to achieve the condition that sample probes are exposed to the same ambient temperature as the primary device. The final rule incorporates Table 1 in API 14.1 for the sample probe length.
§ 3175.113 – Spot samples – general requirements	§ 3175.113 – Spot samples – general requirements	The final rule allows operators to submit monthly or quarterly schedules of sampling to the BLM in lieu of a 72-hour notice. The final rule no longer requires sample cylinders to be made of stainless steel as long as they comply with API 14.1, Subsection 9.1. The final rule no longer requires sample cylinders to be sealed after cleaning. The final rule no longer requires GC filters to be cleaned or replaced. The final rule requires operators using portable GCs to run samples until three consecutive samples

		are within 16 Btu per standard cubic foot (Btu/scf) for high-volume FMPs and 8 Btu/scf for very-high-volume FMPs. The final rule requires the heating value to be calculated from the average of the three consecutive samples or the median heating value.
§ 3175.114 – Spot samples – allowable methods	§ 3175.114 – Spot samples – allowable methods	None.
§ 3175.115 – Spot samples – frequency	§ 3175.115 – Spot samples – frequency	The final rule does not allow the BLM to change the sampling frequency for high-volume FMPs until 2 years of analyses have been obtained, and 1 year of analyses for very-high-volume FMPs. The final rule eliminates the requirement for weekly sampling and the use of composite or on-line GCs for high-volume FMPs.
§ 3175.116 – Composite sampling methods	§ 3175.116 – Composite sampling methods	None.
§ 3175.117 – On-line gas chromatographs	§ 3175.117 – On-line gas chromatographs	None.
§ 3175.118 – Gas chromatograph requirements	§ 3175.118 – Gas chromatograph requirements	The final rule requires an un-normalized mole percent between 97 and 103. The final rule requires that portable GCs are verified every 7 days – the same as laboratory GCs. The final rule eliminates the requirement that the gas used for verification must be different from the gas used for calibration. Instead, the final rule adds a requirement that all new calibration gas must be authenticated and maintained per GPA 2198-03. The final rule requires verification if the composition determined by the GC varies from the composition of the calibration gas by more than the reproducibility in GPA 2261-13. The final rule requires that chromatograms generated during verification must be retained. The final rule incorporates GPA 2286-14 for obtaining an extended analysis.

§ 3175.119 – Components to analyze	§ 3175.119 – Components to analyze	The final rule requires an extended analysis if C6+ is greater than 0.5 mole percent; however, the final rule allows operators to take periodic extended analyses and use that to adjust the assumed C6+ split in lieu of requiring an extended analysis for each sample.
§ 3175.120 – Gas analysis report requirements	§ 3175.120 – Gas analysis report requirements	The final rule requires operators to submit the C6+ split if requested by the BLM.
§ 3175.121 – Effective date of a spot or composite gas sample	§ 3175.121 – Effective date of a spot or composite gas sample	The final rule changes the effective date for composite sampling to the month in which the sample cylinder was removed. The final rule clarifies that report requirements are not retroactive.
§ 3175.125 – Calculation of heating value and volume	§ 3175.125 – Calculation of heating value and volume	None.
§ 3175.126 – Reporting of heating value and volume	§ 3175.126 – Reporting of heating value and volume	The final rule allows operators to adjust the C6+ split based on periodic extended analyses. The final rule eliminates prescriptive methods for estimating volume and heating value. The final rule requires operators to notify the BLM within 72 hours of discovering malfunctioning equipment.
§ 3175.130 – Transducer testing protocol	§ 3175.130 – Transducer testing protocol	None.
§ 3175.131 – General requirements for transducer testing	§ 3175.131 – General requirements for transducer testing	The final rule allows in-house testing as long as the facility meets the definition for a qualified test facility.
§ 3175.132 – Testing of reference accuracy	§ 3175.132 – Testing of reference accuracy	None.
§ 3175.133 – Testing of influence effects	§ 3175.133 – Testing of influence effects	The final rule eliminates the requirement to perform a long-term stability test.
§ 3175.134 – Transducer test reporting	§ 3175.134 – Transducer test reporting	None.
§ 3175.135 – Uncertainty determination	§ 3175.135 – Uncertainty determination	None.
§ 3175.140 – Flow-computer software	§ 3175.140 – Flow-computer software	The final rule clarifies that the BLM approval of a version of flow-computer

testing	testing	software is specific to the make and model of the EFC in which it is used.
§ 3175.141 – General requirements for flow-computer software testing	§ 3175.141 – General requirements for flow-computer software testing	None.
§ 3175.142 – Required static tests	§ 3175.142 – Required static tests	None.
§ 3175.143 – Required dynamic tests	§ 3175.143 – Required dynamic tests	None.
§ 3175.144 – Flow-computer software test reporting	§ 3175.144 – Flow-computer software test reporting	None.
§ 3175.150 – Immediate assessments	§ 3175.150 – Immediate assessments	None.
Appendix 1.A to Subpart 3175	None	Removed Appendix 1.A.
Appendix 1.B to Subpart 3175	None	Removed Appendix 1.B.
Appendix 2 to Subpart 3175	Appendix A to Subpart 3175	None.

B. General Overview of Comments Received

This section presents and responds to general comments on the proposed rule received by the BLM. Comments on specific provisions of the proposed rule are addressed in the Section-by-Section analysis as part of the explanation of the provisions included in this final rule.

Administrative delay

The BLM received numerous comments stating the new rule will cause additional delays and backlogs for both the BLM and industry because of all the additional paperwork and inspections required by the new rule. The BLM has analyzed and disclosed the burdens for industry in the Economic and Threshold Analysis prepared as part of this rulemaking process and in the Paperwork Reduction Act portion of this preamble. Some of the burdens are usual and customary, since they are required by gas sales contracts and/or industry standards. The BLM has determined that the remaining burdens are necessary in order to ensure accurate measurement and reporting.

The BLM also acknowledges that implementation of the rule will require additional BLM staff time. The BLM has analyzed and disclosed the Federal burdens that will result from this rule. The BLM is taking steps to address the issue of streamlining administrative processes, including strategic investments in technology and repeatedly requesting additional resources during the appropriations process. The BLM will continue to pay attention to this issue during the implementation period. The BLM did not make any changes to the rule in response to these comments.

Inspection and Enforcement handbook

As was stated in the preamble of the proposed rule, this final rule removes the enforcement, corrective action, and abatement period provisions of Order 5. 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 Authorized Officer (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 explained in the proposed rule, this change allows the BLM to make a case-by-case determination of the severity of a particular violation, based on applicable definitions in the regulations.

Several comments objected, saying that this course of action was inconsistent with the APA. One such commenter stated its objection as follows:

> BLM's proposal would completely eliminate the enforcement infrastructure prescribed in Onshore Order No. 5, including major and minor violations, corrective actions, and abatement periods…. Removing the enforcement provisions from the realm of transparent, publicly reviewable regulations that were promulgated with notice and comment, and concealing them in non-public policy documents that can be altered in the absence of public input, is inconsistent with the requirements of the APA. BLM-2015-0005-0058 (December 15, 2015).

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. Moreover, 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 Enforcement Handbook, that will provide the legal basis for the BLM's enforcement actions. Put another way, BLM's enforcement actions must be consistent with these regulations irrespective of what may be contained in its Inspection and Enforcement Handbook. It should also be noted, it is this rule and other duly promulgated regulations that establish these standards to which an operator will be held consistent with Administrative Procedure Act (APA) requirements.

As to the concern about public notice and comment processes, it should be noted that internal guidance documents that direct agency personnel on how to implement existing agency policies are not required to follow the public notice and comment process. No change to the rule resulted from these comments.

One commenter suggested that the BLM should retain discretionary case-by-case enforcement of requirements as is currently done under Order 5. Although the BLM disagrees with the premise of the comment regarding the existing requirements of Order 5, the intent of the Inspection and Enforcement Handbook is to provide guidance to BLM inspectors on how to apply the provisions of its oil and gas rules in a consistent manner. As noted above, it will not establish new requirements or obligations. It also will not alter the BLM's case-by-case discretion with respect to any particular enforcement action. The BLM did not make any changes to the rule based on this comment.

Several commenters suggested that the BLM should post the Inspection and Enforcement Handbook on the website. The BLM agrees with this comment and will post the enforcement handbook upon its completion, and will otherwise make it available to the public at any BLM office.

One commenter suggested that the BLM should develop the Inspection and Enforcement Handbook with input from industry. The BLM disagrees with this comment since the handbook is intended to provide internal guidance to BLM inspectors. However, as the Handbook is developed, the BLM will determine the appropriate process to use, including consideration of appropriate opportunities to obtain input from stakeholders. The BLM did not make any changes to the rule as a result of this comment.

One commenter asked if the BLM will publish the Inspection and Enforcement Handbook at the same time as the final rule. For the preceding reasons, the BLM has determined that it is not necessary to release the handbook with this final rule. However, the BLM intends to develop the Handbook within 1 year of the effective date of the proposed rule, which is the earliest date by which the provisions of this rule will go into effect. The BLM did not make any changes to the rule as a result of this comment.

One commenter asked that the BLM provide the economic analysis of developing an Inspection and Enforcement Handbook instead of including enforcement actions in the rule and for moving away from the more discretionary enforcement approach to more immediate assessments. The BLM does not agree with the characterization of Order 5 and the current approach. Also, there have always been immediate assessments, and the BLM has simply expanded the list of actions potentially subject to an immediate assessment. With respect to the requested economic analysis, the BLM does not believe that there is any economic impact in removing enforcement guidance from the rule and placing it in an enforcement handbook. Additionally, because the BLM assumes compliance for purposes of assessing the impact of a rule, the BLM does not believe that it is appropriate to analyze the economic impacts of immediate assessments. The BLM did not make any changes to the rule as a result of this comment.

National Technology Transfer and Advancement Act of 1995

One commenter stated that, per the National Technology Transfer and Advancement Act (NTTAA), codified as a note to 15 U.S.C. 272, the BLM must adopt API standards in whole or justify to the Office of Management and Budget (OMB) why this does not meet the agency mission. The NTTAA directs agencies to utilize technical standards that are developed by voluntary consensus standards bodies. Some commenters argued that the NTTAA obligates the BLM to adopt all gas measurement standards developed by voluntary consensus standards bodies.

The commenters' assertion 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 OMB's guidance for implementing the NTTAA defines "impractical" to include circumstances in which 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, p. 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, p. 25). The BLM has studied the available voluntary consensus standards for gas 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, less feasible, or less useful. In addition, the commenters' reading of the NTTAA would, contrary to OMB guidance, inappropriately preempt the

BLM's statutory authority to promulgate rules and regulations that it deems "necessary" to accomplish the purposes of the applicable statutory directives, including the Mineral Leasing Act (MLA) and the Federal Oil and Gas Royalty Management Act (FOGRMA).

Retroactivity

Several commenters argued that the rule is impermissibly "retroactive." These comments argued that the rule is retroactive because it will apply to existing measurement systems that predate the rule's effective date. 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 final rule does not attach any new legal consequence to the use of existing measurements systems prior to the rule's effective date. 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 business 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).

This rule does not impose liability for nor require changes to measurements made prior to the rule's enactment; rather the rule requires measurements taken as required by the rule after the effective date of the rule (that is, going forward) at both new and existing facilities to satisfy the performance standards established by the final rule. Thus, despite the fact that this rule may require operators to update or modify their existing measurement systems, the rule is prospective – not retroactive – in nature.

Availability of Material Incorporated by Reference

The BLM received comments arguing that the incorporated API and GPA standards were not adequately available to the public during the comment period. The BLM's obligation to make the incorporated standards available to the public derives from the Freedom of Information Act (FOIA), which requires agencies to publish "substantive rules of general applicability adopted as authorized by law" in the Federal Register (5 U.S.C. 552(a)(1)(D)). Under FOIA, "matter reasonably available to the class of persons affected thereby is deemed published in the Federal Register when incorporated by reference therein with the approval of the Director of the Federal Register" (id. section 552(a)(1)). For the following reasons, the industry standards incorporated by reference in the final rule are – and have been – "reasonably available" to the public as required by FOIA. As discussed in the notice of proposed rulemaking, all of the API and GPA standards incorporated by reference in the rule have been available for inspection at the BLM's Washington, D.C. office and at all BLM offices with jurisdiction over oil and gas activities (80 FR 61646, 61655). All of the incorporated API standards have also been available for inspection at API's Washington, D.C. office; API has also provided free, read-only access to some of the incorporated standards online (id.). All of the incorporated GPA standards have also been available for inspection at GPA's Tulsa, Oklahoma office (id.). Finally, all of the incorporated API and GPA standards have been, and continue to be, available for purchase from API and GPA.

Some commenters stated that local BLM offices were unable to provide them with access to the incorporated standards. These occurrences resulted from the fact that, although all the local BLM offices have electronic access to the incorporated standards, not all local office personnel were aware of how to access the incorporated standards. The BLM plans to carry out a training program to ensure that personnel at local BLM offices can readily access the incorporated standards and provide them to interested members of the public when requested. Given the multiple avenues available for accessing the incorporated standards, we do not believe that the handful of reported occurrences in which staff were unable to access the standards prevented stakeholders from accessing and reviewing the documents as part of their review of the proposed rule. Therefore the BLM has met its obligations under FOIA and the APA with respect to those standards.

It should be noted that the BLM received numerous comments regarding the adoption of specific API and GPA standards in the proposed rule. Most of these comments are addressed in connection with the relevant sections of the rule (§§ 3175.30, 3175.40, 3175.110, 3175.130, and 3175.140; see section II. C of this preamble below).

Duplication of State rules

The BLM received one comment stating that this rule is duplicative of State rules. During the development of this rule, the BLM researched existing State rules related to gas measurement and crafted the rule to avoid conflicts with applicable State standards. The commenter did not identify any inconsistencies.

Moreover, the BLM is issuing this rule in fulfillment of its fiduciary obligation to assure that Federal and Indian gas is properly measured and that all royalties due under Federal law are paid. The fact that some States may have similar requirements does not render this rule duplicative, as the BLM has an independent responsibility to meet its fiduciary obligations for the resources it manages.

Definitions hard to find

One commenter stated that separately publishing the proposed rules to update and replace Order 3 (site security), Order 4 (oil measurement), and Order 5 made the definitions hard to find. The BLM does not agree with this comment. The proposed rule to replace Order 3 also established a new part 3170 that will contain all three rules to replace Orders 3, 4, and 5, including a definitions section containing provisions common to all three rules. The proposed rules, in most instances, contained all of the key definitions unique to each subpart. For example, definitions specific to gas measurement are found in the definitions section of this rule. Definitions that are used in two or more subparts are found in the definitions section of subpart 3170 in order to reduce redundancy and ensure consistency. Additionally, the BLM extended the comment periods for all three proposed rules to ensure that they were all open and available for comments at the same time.

Moreover, since all three final rules to replace Orders 3, 4, and 5 will appear in the CFR in a new part 3170, this will ensure that the definitions will be easy to find during implementation. The BLM did not make any changes to the rule in response to this comment.

Not enough information

The BLM received several comments stating the proposed rule did not contain a description of all the calculations, assumptions, and enforcement actions, nor an explanation of why certain industry standards were or were not incorporated by reference. The BLM believes that a thorough description of the assumptions and rationale for the proposed changes was provided in the preamble to the proposed rule. The BLM also published heating value variability and uncertainty calculations in the BLM Gas Variability Study, which was referenced numerous times in the preamble and posted as a supporting document on the www.regulations.gov website, along with the proposed rule. The BLM has been enforcing flow-rate uncertainty standards since 2009 and the calculations that the BLM uses to determine uncertainty have been publicly available since that time. Additionally, all of the economic assumptions used in the proposed rule were also posted on the www.regulations.gov website in a supporting document, along with the proposed rule ("Proposed 3175 Economic Analysis").

With respect to incorporated industry standards, the BLM incorporated the standards that are relevant and appropriate to the proposed rules. These include standards that directly relate to the measurement of volume and heating value typical of the technologies currently used at BLM points of royalty measurement (now called FMPs). 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, or standards that cover equipment and processes that are very rarely used for gas measurement at the lease level, such as those covering Coriolis meters, turbine meters, or ultrasonic meters. That said, the PMT may, on a case-by-case basis, consider recommending for approval the use of such standards in lieu of compliance with the identified standards if and when it is asked to review such requests for approval to employ such standards in the field in the future. The commenters' questions regarding enforcement were addressed previously. The BLM did not make any changes to the rule based on these comments.

Only use performance goals

Numerous comments objected to the equipment standards in the proposed rule and suggested that the BLM only rely on performance goals because the equipment standards will become obsolete as technology progresses. The BLM agrees that some of the equipment standards may become obsolete as technology progresses. As a result, the BLM included performance standards in § 3175.31 of the final rule (§ 3175.30 in the proposed rule), along with a process for the BLM – through the PMT – to assess and approve new technologies over time. The BLM also agrees that, with appropriate oversight, performance goals should be sufficient without the explicit equipment standards. The BLM fully supports the concept of allowing industry to determine the best and most cost-effective way to meet performance goals. As a result, this rule allows the BLM to approve technologies and processes that are different from the specific equipment standards in the rule as long as they meet or exceed the stated performance goals in § 3175.31. It should be noted that unlike the existing variance process, which requires local field office approval on a case-by-case basis, the PMT process outlined in the proposed and final rules is structured such that the PMT needs to review and approve technology only once on a nation-wide basis; subsequently, facilities will be able to rely on those PMT reviews and approvals as long as they comply with any applicable conditions of approval.

While the BLM recognizes the value of performance-based standards, it is nevertheless providing equipment standards for two reasons. First, the BLM has over 4,000 operators of Federal and Indian leases and the vast majority of these operators are small companies without measurement personnel on staff. Requiring a small operator to achieve, for example, an overall meter measurement uncertainty of ±3 percent, without any equipment standards, would likely require the operator to hire measurement specialists to determine the equipment and operating conditions necessary to meet the uncertainty requirement on their leases. The BLM equipment standards provide a "cookbook" for how to achieve the performance goals established in the rule for operators that do not have the expertise, resources, or interest in innovating new technology or processes to meet a performance goal. In the BLM's experience, this cookbook approach is useful to smaller operators and is a feature of Order 5 that was retained in the final rule.

Second, it would be virtually impossible for the BLM to enforce a performance goal without a full understanding of the technology and process the operator is using to achieve that goal. In addition, this would require customized enforcement procedures for every meter installation. For the BLM to implement this approach, it would need to approve all new FMP installations on a case-by-case basis, which would include: (1) Conducting a detailed analysis on the operator's proposal regarding how they would achieve the performance goals in the rule; and (2) Developing the enforcement procedures specific to that approval. This would unnecessarily drive up costs for both the BLM and industry and could result in backlogs of new measurement applications, both of which the BLM (and likely industry as well) would prefer to avoid.

Under this rule, the BLM has to approve only those technologies and processes that are different from the equipment standards listed in the rule. The BLM did not make any changes to the rule based on these comments.

New rule not needed

The BLM received several comments stating that Order 5 works well as written and a new rule is not needed. The BLM disagrees with these comments. Order 5 incorporates one industry standard – AGA Report No. 3 from 1985. This standard addresses the installation requirements for orifice meters and the calculation of flow rate from an orifice meter. Installing an orifice meter using this standard can cause significant bias in measurement. This standard has been revised numerous times since 1985 based on new data and better calculation techniques. In addition, Order 5 does not incorporate standards for the calculation of volume from orifice meters, the calculation of supercompressibility used in flow-rate calculations, or the collection and analysis of gas samples. Further, Order 5 does not state overall performance goals or include a process to analyze and apply new technology on a national basis. Lastly, Order 5 does not cover EGM systems that now make up approximately 90 percent of all gas meters in the field. These deficiencies are what led the Subcommittee, the OIG, and the GAO to conclude that the BLM's gas measurement regulations are outdated and in need of an update. Management of onshore Federal oil and gas resources is on the GAO's High Risk List, in large part due to its outdated measurement regulations. The BLM did not make any changes to the rule as a result of these comments. Further evidence regarding the inadequacy of Order 5 can be found in the fact that the BLM has had to issue NTLs supplementing its requirements.

One commenter stated that no third-party proof exists to demonstrate that the proposed changes would improve measurement. The BLM did not make any changes to the rule based on this comment. While the rulemaking process does not require third-party confirmation that the proposed changes would improve measurement, the BLM is confident that the rule will result in substantial improvements to both the accuracy and verifiability of measurement.

For example, existing Order 5 has only one requirement relating to the determination of heating value – that it be determined once per year. Order 5 has no requirements as to where the sample is taken, how it is taken, how it is analyzed, or how it is reported. Nor does Order 5 incorporate any industry standards relating to sampling and analysis, even though those have been developed. As illustrated in the Background Section of this preamble, inaccurate heating value determination has the same impact on royalty calculations as errors in volume determination. As explained in the preamble to the proposed rule, the BLM has shown that Order 5's existing requirement to sample once per year is inadequate. BLM's Gas Variability Study demonstrated significant variability in heating value for individual facilities that would not be captured by once per year sampling and that may be correlated to the lack of any BLM standards on how it is determined. This final rule, on the other hand, incorporates five consensus industry standards relating to the sampling and analysis of heating values and sets standards on heating value uncertainty, sample probes, sample cylinders, GCs, and reporting.

One commenter stated that the new rule will not aid in consistency. The BLM disagrees with this comment. Order 5 included a variance process to address new technology and to allow the BLM to approve alternate methodology that accomplished the goals of the Order. Unfortunately, Order 5 did not state what those goals were and left the review and approval process at the field office level. This resulted in inconsistent review of variances from office to office, an issue which was raised by industry, the GAO, and the OIG. This final rule establishes a new national process for the review and approval of new technology and/or alternate measurement methodologies through a centralized team, the PMT. Once approved, the BLM will post the device or process on the BLM website along with any conditions for its use developed by the PMT. Operators can rely on those approvals without seeking a subsequent authorization. This centralized review will dramatically improve consistency over the current process. The BLM did not make any changes to the rule as a result of this comment.

Use variance process for small operators

One commenter suggested a variance process for small operators who cannot comply with API standards. Consistent with the comment, the final rule includes a standard process for any operator to obtain BLM approval for an alternate methodology, as long as that methodology meets or exceeds the performance goals set out in § 3175.31. Recognizing the economics of lower-volume properties, the final rule adopts changes relative to the proposed rule that will reduce the requirements on those properties, which will reduce compliance costs for operators, many of which could be smaller operators. Those specific changes are discussed later in the preamble, in the Section-by-Section analysis. The BLM did not make any changes to the rule as a result of this comment.

Transporters

The BLM received numerous comments objecting to the provision in the proposed rule to require transporters to keep measurement records. It should be noted at the outset that this change was the result of statutory requirements imposed by Congress under FOGRMA and the changes in the proposed rule are consistent with that statutory direction. Commenters objected to the requirement that both the operator and the transporter keep duplicate records and noted that transporters will have to modify their computer systems to comply with BLM requirements, including the requirement to store the FMP number. Based on other comments (see the discussion of §§ 3175.101(b)(4) and 3175.104(a)(1) in section II.C. of this preamble), the BLM has decided that it will not require operators, purchasers, or transporters to include the FMP number as part of the flow-computer display or include it on audit trail records. Parties may continue to use unique meter station identifiers. The FMP number is now only required on the Oil and Gas Operations Reports (OGORs) that the operator submits to ONRR. The BLM realizes that this requirement could result in duplicate sets of records in some cases. However, when the BLM audits an FMP that is owned by a transporter or purchaser rather than the operator, the operator may not have access to the complete audit trail. In these cases, the records held by the transporter would not be duplicates.

A few commenters asked for clarification of which records the transporter or purchaser will be responsible for maintaining. The transporter or purchaser is responsible for maintaining all records required by this subpart for FMPs that are owned by the transporter or purchaser for the timeframes listed in 43 CFR 3170.7. The BLM did not make any changes to the rule based on these comments.

One commenter stated that there is no indication that the records currently maintained by the transporter or purchaser are inadequate. If the records owned by the transporter or purchaser are adequate, as implied by the comment, then this rule should not have any additional impact on the transporter or purchaser. The BLM did not make any changes to the rule based on this comment.

One commenter stated that transporters and purchasers should not be subject to immediate assessments. The BLM agrees with this comment and has removed purchasers and transporters from the immediate assessment section in § 3175.150 (see discussion under that section).

Will deter development and reduce royalty

The BLM received many comments stating that the proposed rule would deter development on Federal and Indian oil and gas leases and result in lower royalty due to operators shutting in their production rather than complying. The commenters stated that the cost, complexity, delays, and new reporting requirements are primary reasons. One commenter stated that the rule would be especially burdensome for small operators. In response to comments on specific parts of the proposed rule, the BLM made numerous changes in the final rule that should provide significant economic relief to operators on Federal and Indian leases. These changes include:

- The threshold between very-low- and low-volume is raised from 15 Mcf/day to 35 Mcf/day, and the threshold between low- and high-volume is raised from 100 Mcf/day to 200 Mcf/day;
- Existing meter tubes at low- and high-volume FMPs are grandfathered[7] from the construction, length, and eccentricity requirements in § 3175.80(f) and (k), and from API 14.3.2, Subsection 6.2, although they still must comply with the 1985 AGA

[7] The term "grandfathered" means that meters in use prior to the effective date of the rule do not have to comply with those portions of the rule.

Report No. 3 standards (very-low-volume FMPs are exempt from meter tube requirements altogether);

- Flow-computer software at very-low-, low-, and high-volume FMPs are grandfathered and flow computers no longer have to display the FMP number;
- Accounting systems no longer have to include the FMP number;
- Composite sampling systems or on-line GCs are no longer required on high-volume FMPs, and they were never required for very-low- and low-volume FMPs;
- Gauge lines with a 3/8-inch nominal diameter are acceptable;
- Implementation of the requirement for PMT approval of existing equipment and gas analysis input into the Gas Analysis Reporting and Verification System (GARVS) is delayed for 2 years after the effective date of the final rule;
- Long-term stability tests for transducers is longer required;
- The PMT has the ability to approve existing transducers using existing data from manufacturers;
- Multiple analyses for laboratory GCs are no longer required; and
- C9+ analysis is only required periodically for high- and very-high-volume FMPs and only if the mole percentage for C6+ exceeds 0.5 percent.

Several commenters stated that the new rules could reduce royalty by increasing the costs of metering, which, in turn, operators could claim as a transportation deduction. The BLM consulted ONRR on this comment and ONRR confirmed that there are no circumstances in which an operator could claim the costs of metering as a transportation deduction even if the meter was owned by a transporter or purchaser. The BLM did not make any changes to the rule as a result of this comment.

Costs Underestimated

The BLM received a number of comments stating that the Economic and Threshold Analysis did not adequately account for all costs associated with the proposed rule. Several commenters said that the estimated cost of the rule should include the costs to the government of reduced royalty payments, as well as lost tax revenues that will result from reduced State and local employment. However, the premise of this argument is based upon the commenter's assumption that operators would have had to shut in wells as a result of the rule. The numerous revisions to reduce the cost of the final rule described above will significantly reduce costs from the requirements of the proposed rule. The BLM does not believe that a significant number of shut-ins will occur as a result of this rule. Although the BLM made significant changes to the rule based on concerns over cost, the BLM did not make any changes based on these specific comments.

Cost-Benefit Analysis

Several commenters stated that the BLM should have done a cost-benefit analysis of the rule in which the estimated costs are compared against the resultant improvement in expected royalty revenue. There are several flaws in this argument. Notably, commenters are presuming that the only purpose of the rule is to eliminate measurement bias, and that FMPs are currently biased to read low. Bias is mismeasurement that results in a measured quantity that is either predictably higher than or predictably lower than the actual value of the quantity. If the BLM were aware that FMPs were biased to read low, then the commenter's assertions would be correct. In other words, if the sole intent of the rule were to eliminate bias to the low side and the BLM were able to quantify that bias, then the BLM could perform a cost-benefit analysis comparing the cost of the rule to the increase in royalty payments resulting from the elimination of the bias to the low side. However, the BLM has no data to support the proposition that FMPs are biased exclusively to the low side (with the exception of Btu reporting and potentially also gas sampling practices). In addition, the elimination of bias, either high or low, is only one of the performance goals of the rule. The other performance goals are to establish uncertainty limits for high- and very-high-volume FMPs and to require that all aspects of the measurement are independently verifiable by the BLM. Together, these performance goals are designed to ensure that the American public and Indian tribes and allottees are receiving a fair return for gas produced from their leases.

Whether the rule will result in an increase in royalty, a decrease in royalty, or no change in royalty was not a consideration in the rule-making process. The rule is intended to obtain accurate measurement of the gas produced from Federal and Indian leases. The BLM did not make any changes to the rule based on these comments.

Withdraw rule

Two commenters recommended that the BLM withdraw the rule because it is incomplete and potentially devastating to the industry. The commenters did not elaborate as to why the rule is incomplete or why it would potentially be devastating to the industry. The BLM believes the proposed rule was complete and met all legal requirements of a proposed rule under the APA. The BLM also made significant changes to the proposed rule aimed at reducing costs, especially at low-volume facilities. These specific changes are discussed elsewhere. The BLM did not make any changes to the rule as a result of these comments.

Tone

One commenter objected to the tone of the rule stating that the rule implies that operators are intentionally trying to underpay royalty. The commenter did not provide any specific examples. The BLM does not agree with this comment and did not intend to make such an implication. The BLM recognizes that measurement error goes in both directions and, as result, it might result in either over- or under-reporting of production. The BLM did not make any changes to the proposed rule as a result of this comment.

Executive Order 13211

The BLM received several comments stating that no data were presented to support the assertion that the rules will not affect the energy supply, as required by Executive Order (E.O.) 13211. The commenters stated that the rule will result in delays in distribution due to the backlog of new equipment that the BLM is requiring for existing FMPs. One commenter stated that the BLM needs to study the effects of the rule on transportation.

E.O. 13211 requires an agency to prepare a "Statement of Energy Effects" when it undertakes a "significant energy action." There are two ways in which an agency's action can constitute a significant energy action: (1) The action is a "significant regulatory action" under E.O. 12866 if it is "likely to have a significant adverse impact on the supply, distribution, or use of energy"; or, (2) The action is designated as a significant energy action by the Office of Information and Regulatory Affairs (OIRA). This rule is not a significant energy action because it will not have a significant adverse impact on the supply, distribution, or use of energy, and it has not been designated as a significant energy action by OIRA. The BLM's conclusion that this rule is not a significant energy action is based on its analysis of the economic impact of the proposed rule.

Additionally, in response to comments received, the BLM made numerous changes to the proposed rule that will reduce compliance costs and the potential for any approval backlogs for new equipment that may have resulted from the proposed rule. These changes include:

- The grandfathering of 98.7 percent of all meter tubes in place at FMPs as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] from having to meet the construction and installation standards of API 14.3.2 (2000);
- The grandfathering of 88.7 percent of all flow computers in place at FMPs as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] from having to use the latest flow-rate calculation methods of API 14.3.3 (2013);
- The grandfathering of 100 percent of all transducers in place as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], from the testing protocol required in § 3175.43, if the manufacturers submit existing test data to the PMT and the BLM approves the transducer based on that existing data; and
- Elimination of the requirement for flow computers to display the FMP number, which may have required some older model flow computers to be replaced.

C. Section-by-Section Analysis and Comment Responses

This section describes the various regulatory changes made by this final rule. First, it describes the content of the specific sections of subpart 3175, explains any changes between the proposed and final rules, and responds to section-specific comments on the proposed rule received by the BLM during the comment period. Following that discussion, it describes changes and revisions being made to 43 CFR 3162.7-3, 3163.1, and 3164.1. The proposed rule to replace Order 5 also proposed changes to 43 CFR 3163.2 and 3165.3. The proposed revisions are addressed in the final rule to replace Order 3 (being released concurrently with this rule) and are not discussed further here.

§ 3175.10 – Definitions and acronyms

Section 3175.10 includes numerous new definitions unique to this rule because much of the terminology used in the rule is technical in nature and may not be readily understood by all readers or may have a specific meaning in the context of this rule. As explained in the preamble to the proposed rule, the BLM also added other definitions because their meanings, as used in the rule, may be different from what is commonly understood, or the definition includes a specific regulatory requirement.

Definitions of terms commonly used in gas measurement or which are already defined in 43 CFR parts 3000, 3100, 3160, or subpart 3170 are not discussed in this preamble.

The rule defines the terms “primary device,” “secondary device,” and “tertiary device,” which together measure the amount of natural gas flow. All differential types of gas meters consist of at least a primary device and a secondary device.

Primary device

The “primary device” is the equipment that creates a measureable and predictable pressure drop in response to the flow rate of fluid through the pipeline. It includes the pressure-drop device, device holder, pressure taps, required lengths of pipe upstream and downstream of the pressure-drop device, and any flow conditioners that may be used to establish a fully developed symmetrical flow profile.

A flange-tapped orifice plate is the most common primary device found on Federal and Indian leases. It operates by accelerating the gas as it flows through the device, similar to placing one's thumb at the end of a garden hose. This acceleration creates a difference between the pressure upstream of the orifice and the pressure downstream of the orifice, which is known as differential pressure. It is the only primary device that is approved in Order 5 and in this rule and would not require further specific approval. Other primary devices, such as cone-type meters, operate much like orifice plates and the BLM could consider them for approval under the requirements of § 3175.47.

One commenter recommended that the BLM include linear meters in the definition of "primary device." The definition of primary device in the proposed rule was specific to differential-type meters. The BLM did not make any changes to the rule based on this comment. The rule allows the PMT to recommend approval of linear devices by make, model, and size. In its recommendation, the PMT can include requirements for a linear meter along with a definition of a linear-meter primary device, if needed. However, the performance standards in this rule are based around differential-type meters. As a result, there are many requirements pertaining specifically to the primary device of differential-type meters. A definition of "primary device" is in § 3175.10 of the rule to avoid having to describe what a primary device is every time it is mentioned in the rule. Adding linear meters to the definition would make the requirements in the rule confusing and cumbersome. For example, § 3175.47 requires operators or manufacturers to test primary devices other than orifice plates under API 22.2, which is specific to differential types of primary devices. If linear-meter primary devices were added to the definition, then the requirement in § 3175.47 would have to specify that it applies only to differential types of primary devices, largely defeating the purpose of having the definition, especially considering there are no current or proposed API testing protocols for linear meters.

Secondary device

The “secondary device” measures the differential pressure along with static pressure and temperature. The “secondary device” consists of the differential-pressure, static-pressure, or temperature transducers in an EGM system or a mechanical recorder (including the differential pressure, static pressure, and temperature elements, and the clock, pens, pen linkages, and circular chart). The BLM did not receive any comments on this definition.

Tertiary device

In the case of an EGM system, there is also a “tertiary device,” namely, the flow computer and associated memory, calculation, and display functions, which calculates volume and flow rate based on data received from the transducers and other data programmed into the flow computer. The BLM did not receive any comments on this definition.

Self-contained versus component-type EGM systems

The rule adds definitions for “component-type” and “self-contained” EGM systems. The distinction is necessary for the determination of overall measurement uncertainty. To determine overall measurement uncertainty under § 3175.31(a), it is necessary to know the uncertainty, or risk of measurement error, of the transducers that are part of the EGM system. Therefore, the BLM needs to be able to identify the make, model, and upper range limit (URL) of each transducer because the uncertainty of the transducer varies among makes, models, and URLs.

Some EGM systems are sold as a complete package, defined as a self-contained EGM system, which includes the differential-pressure, static-pressure, and temperature transducers, as well as the flow computer. The EGM package is identified by one make and model number. The BLM can access the performance specifications of all three transducers through the one model number, as long as the transducers have not been replaced by different makes or models. The BLM did not receive any comments on this definition.

Other EGM systems are assembled using a variety of transducers and flow computers and cannot be identified by a single make and model number. Instead, the BLM would identify each transducer by its own make and model. These are defined as “component” EGM systems. Component systems include EGM systems that started out as self-contained systems, but one or more of whose transducers have been changed to a different make and model. The BLM did not receive any comments on this definition.

Hydrocarbon dew point

The rule adds a definition for “hydrocarbon dew point” (HCDP). The HCDP is the temperature at which liquids begin to form within a gas mixture. Because it is not common to determine HCDPs for wellhead metering applications on Federal and Indian leases, the BLM established a default value using the gas temperature at the meter. By definition, the gas in a separator (if one is used) is in equilibrium with the natural gas liquids, which are at the HCDP. Cooler temperatures between the outlet of the separator and the primary device can result in condensation of heavy gas components, in which case the lower temperature at the primary device would still represent the HCDP at the primary device because the liquid and gas phases would again be in equilibrium. The AO may approve a different HCDP if data from an equation-of-state, chilled mirror, or other approved method are submitted. The BLM did not receive any comments on the definition of HCDP.

Upper and lower calibrated limit

The rule adopts the definitions of “lower calibrated limit” and “upper calibrated limit” from the API Manual of Petroleum Measurement Standards (MPMS) 21.1. The upper and lower calibrated limits are the maximum and minimum values, respectively, for which the transducer was calibrated using certified test equipment. These terms replace the term “span” as used in the statewide NTLs for EFCs. The BLM did not receive any comments on these definitions.

Redundancy verification

The term “redundancy verification” is added to address verifications done by comparing the readings from two sets of transducers installed on the same primary device. The BLM did not receive any comments on this definition.

FMP categories

The proposed rule defined four terms to describe categories of FMPs: “Marginal volume,” “low volume,” “high volume,” and “very high volume.” The BLM proposed these categories for purposes of delineating applicable requirements based on the average flow rate measured by an FMP. The proposed categories were as follows: A marginal-volume FMP would have had an average flow rate of 15 Mcf/day or less; a low-volume FMP would have had an average flow rate greater than 15 Mcf/day, but less than or equal to 100 Mcf/day; a high-volume FMP would have had an average flow rate greater than 100 Mcf/day, but less than or equal to 1,000 Mcf/day; and, a very-high-volume FMP would have had an average flow rate greater than 1,000 Mcf/day. Based on comments received on the proposed rule, changes in market conditions, and additional internal analysis, the BLM has modified two of the three thresholds separating the categories in the final rule. The revised definitions in the final rule are as follows: A very-low-volume FMP (marginal-volume FMP in the proposed rule) has an average flow rate of 35 Mcf/day or less; a low-volume FMP has an average flow rate greater than 35 Mcf/day, but less than or equal to 200 Mcf/day; a high-volume FMP has an average flow rate greater than 200 Mcf/day, but less than or equal to 1,000 Mcf/day. Very-high-volume FMPs continue to have an average flow rate greater than 1,000 Mcf/day. Increasing the thresholds at which an FMP is considered low- or high-volume reduces the number of facilities that are in higher-volume categories, which reduces the overall cost of the rule, because the rule imposes stricter measurement requirements on higher-volume facilities.

The proposed rule defined “marginal-volume FMP” as an FMP that measures a default volume of 15 Mcf/day or less. The BLM replaced the term “marginal-volume FMP” with “very-low-volume FMP” in the final rule to avoid confusion with other rules that use the term “marginal well.” As with the proposed rule, “very-low-volume” FMPs are exempt from many of the requirements in this rule.

The proposed rule’s 15 Mcf/day threshold for a very-low-volume FMP was derived by performing a discounted cash-flow analysis to account for the initial investment of equipment that may be required to comply with the proposed standards applicable to facilities classified as low-volume FMPs. Assumptions in the discounted cash-flow model included:

- $12,000/year/well operating cost (not including measurement-related expense);

- Verification, orifice-plate inspection, meter-tube inspection, and gas sampling expenditures as would be required for a low-volume FMP in the proposed rule;
- A before-tax rate of return (ROR) of 15 percent;
- An exponential production-rate decline of 10 percent per year; and
- A 10-year equipment life.

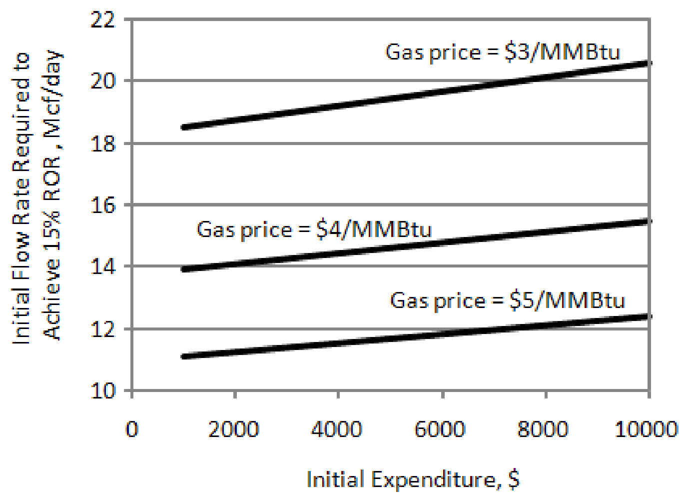

Figure 1

The model calculated the minimum initial flow rate needed to achieve a 15 percent ROR for various levels of investment in measurement equipment that would be required of a low-volume FMP. The ROR would be from the continued sale of produced gas that would otherwise be lost if the lease, unit PA, or CA were shut in. Figure 1 shows the results of the modeling for assumed gas sales prices of $3/MMBtu, $4/MMBtu, and $5/MMBtu.

Both wellhead spot prices (Henry Hub) and New York Mercantile Exchange futures prices for natural gas averaged approximately $4/MMBtu for 2013 and 2014. At that time, the U.S. Energy Information Administration projected the price for natural gas to range between $5/MMBtu and $10/MMBtu through the end of 2040, depending on the rate at which new natural gas discoveries are made and projected economic growth. Assuming a $4/MMBtu gas price from Figure 1, a 15 percent ROR could be achieved for meters with initial flow rates of at least 15 Mcf/day, for an initial investment in metering equipment up to about $8,000. For wells with initial flow rates less than 15 Mcf/day, our analysis indicated that it may not have been profitable to invest in the necessary equipment to meet the proposed requirements for a low-volume FMP. Instead, it would have been more economic for an operator to shut in the FMP. Therefore, 15 Mcf/day was proposed as the default threshold for a very-low-volume FMP, with the AO permitted to approve a higher threshold where circumstances warrant.

The proposed rule would have defined “low-volume FMP” as an FMP flowing at more than 15 Mcf/day, up to 100 Mcf/day. Low-volume FMPs must meet minimum requirements to ensure that measurements are not biased, but they are exempt from the rule’s minimum uncertainty requirements. It was anticipated that this classification in the proposed rule would have encompassed many FMPs, such as those associated with plunger-lift operations, where attainment of minimum uncertainty requirements would be difficult due to the high fluctuation of flow rate and other factors. The costs to retrofit these FMPs to achieve minimum uncertainty levels could be significant, although no economic modeling was performed at the time the proposed rule was written because costs were highly variable and speculative. The exemptions that would be granted for low-volume FMPs are similar to the exemptions granted for meters measuring 100 Mcf/day or less in Order 5 and in the various statewide NTLs covering EFCs.

The proposed rule would have defined “high-volume FMP” as an FMP flowing more than 100 Mcf/day, but not more than 1,000 Mcf/day. Requirements for high-volume

FMPs will ensure that there is no statistically significant bias in the measurement and it will achieve an overall volume measurement of uncertainty of ±3 percent or less and an annual average heating-value uncertainty of ±2 percent. The BLM anticipates that the higher flow rates would make retrofitting to achieve minimum uncertainty levels more economically feasible. The requirements for high-volume FMPs are similar to current BLM requirements as stated in the statewide NTLs for EFCs.

Finally, the proposed rule would have defined “very-high-volume FMP” as an FMP flowing more than 1,000 Mcf/day. The BLM requires that very-high-volume FMPs achieve lower uncertainty than is required for high-volume FMPs (±2 percent, compared to ±3 percent for volume; and ±1 percent, compared to ±2 percent for average annual heating value) and would have increased the frequency of primary device inspections and secondary device verifications. Stricter measurement accuracy requirements for very-high-volume facilities are appropriate due to the risk that mismeasurement will have a significant impact on royalty calculation. The BLM anticipates that FMPs in this class operate under relatively ideal flowing conditions where lower levels of uncertainty are achievable and the economics for making necessary retrofits are favorable.

Many commenters questioned how the BLM determined the flow-rate ranges for the four categories of FMPs in the proposed rule (very-low-, low-, high-, and very-high-volume). Several of the commenters stated that the BLM used economics to determine the very-low-/low-volume threshold, but arbitrarily assigned the other thresholds. The BLM does not agree that the low-/high-volume and high-/very-high-volume thresholds in the proposed rule were “arbitrary.” The BLM did not have the same level of detail in its cost data to do the same level of detailed analysis on the thresholds for the higher-volume categories. The BLM nevertheless did consider existing thresholds in Order 5 and practical considerations for achieving lower uncertainties in setting those thresholds. Ultimately, though, the BLM determined that the cost estimates it had prepared were reasonable and formed a proper basis to set the thresholds used in the final rule. As explained elsewhere in this preamble, the thresholds were set at the point at which the cost of the additional requirements with respect to measurement equals the reduction in royalty risk achieved.

One commenter recommended that the BLM should determine all three thresholds on a cost-benefit basis, setting the thresholds at the level at which the cost of required meter improvements is offset by reduced uncertainty as a result of making the improvement. The commenter also recommended that the BLM should use a 1.5-year "payout" methodology instead of the rate-of-return methodology that the BLM used in the proposed rule. The BLM partially agrees with these comments and developed a Threshold Analysis to support the thresholds used in the final rule (see the discussion on thresholds below and the BLM Threshold Analysis). The requirements in the rule for low-volume FMPs represent the most lenient requirements the BLM can reasonably accept while also meeting its fiduciary obligations to ensure royalty-quality measurement. The only rationale for exempting very-low-volume FMPs from those requirements is to reduce costs to the point that operators truly on the edge of profitability will not shut in production as a result of the rule. The threshold for very-low-volume FMPs, therefore, is the flow rate below which a prudent operator can no longer afford to comply with the requirements for a low-volume FMP and would shut in production if the rule did not include the additional, very-low-volume category. Put differently, the BLM established the very-low-/low-volume threshold based on the minimum flow rate at which a prudent operator could afford to meet the standards for a low-volume FMP.

For the final rule, the BLM accepted the 1.5-year payout methodology suggested by the commenter in lieu of the rate-of-return methodology used in the proposed rule. Also, instead of using an assumed $8,000 investment required to meet the measurement standards for a low-volume FMP, the BLM re-examined the cost differences between the very-low-volume requirements and the low-volume requirements in the final rule. This cost difference was considered the "investment" in the payout methodology. The BLM does not agree that the reduction in uncertainty should be the basis for the "income" side of the payout method. While this may be useful for comparing uncertainty improvement as a function of cost, the BLM does not believe the overall premise is correct. First, the determination of uncertainty reduction between the very-low-volume and low-volume categories is highly speculative. Second, and perhaps more importantly, uncertainty indicates the risk of mismeasurement and does not denote whether that mismeasurement is high or low. The use of uncertainty to determine payout may be misleading to the reader who could incorrectly assume that uncertainty equates to under-measurement in all cases.

Instead of using the reduction in uncertainty as the "income," the BLM used the total income from the well(s) flowing through the FMP. The premise of the payout method for the very-low/low-volume threshold was to simulate the decision-making process of a prudent operator, faced with a choice of either investing the money required to meet the standards of a low-volume FMP or of shutting-in the well(s). In this scenario, the prudent operator would consider the income provided by the continuation of production if they were able to meet the requirements of a low-volume FMP. All of this income would be lost if the well(s) were shut in.

The commenter recommended using the payout approach to set all of the thresholds. The BLM does not believe the payout approach is applicable to the low-/high-volume and high-/very-high-volume thresholds. Instead of using a payout method recommended by the commenter, the BLM used a royalty-risk methodology to determine the low-/high- and high-/very-high-volume thresholds. The BLM determined that it is fair and reasonable to set these thresholds for the higher-volume facilities at the point at which the cost of the additional requirements equals the reduction in royalty risk due to the additional requirements. This approach is appropriate for high-volume facilities because the costs of installing additional measurement equipment at these facilities do not impact their economic viability, since they are producing at a high-enough rate that they generate significant revenues, well in excess of operating costs. For example, a required $30,000 upgrade for a meter flowing at 1,000 Mcf/day would have a payout of 7 days, after operating costs, royalties, and taxes, well below the payout range of 6 to 18 months given by the commenter. A prudent operator would not shut in production in this scenario.

One commenter suggested that the BLM should incorporate the percent Federal or Indian ownership in the determination of flow-rate threshold categories. The BLM did not make any changes to the rule based on this comment because generally the accuracy of the FMP should be based on the flow rate it is measuring regardless of ownership. Implementing this suggestion would also be complex and cumbersome for both operators and the BLM. For example, a BLM inspector would have to multiply the average flow rate of the FMP by the Federal or Indian mineral interest in the agreement in order to determine which requirements the FMPs need to meet.

One commenter raised a concern about an FMP that is operating just over one of the volume thresholds because the operator would still have to spend the money to comply with the threshold, but the FMP would only be making slightly more money than if it were in the next lower category. The BLM did not make any changes to the rule based on this comment because this situation will arise no matter where the thresholds are established. The BLM may provide guidance to its inspectors in the enforcement handbook on how to handle situations in which an FMP is operating just over a threshold.

The BLM received many comments suggesting alternative thresholds for the four categories of FMPs. The following table compares the Mcf/day thresholds from the proposed rule with the alternative suggestions received in the comments:

Threshold	Proposed Rule	Comments		
Very-low/Low	15	50	80	100
Low/High	100	200	500	
High/Very-high	1,000	1,000	2,500	5,000

Comments also included recommendations for removing the very-low-volume category in its entirety and extending the requirements for low-volume FMPs from zero Mcf/day to 100 Mcf/day. Another commenter suggested removing the very-high-volume category and extending the requirements for high-volume FMPs with no upper limit of flow rate. Based on all of the above comments, the BLM re-evaluated the economics of each category and developed new Mcf/day thresholds:

Threshold	Proposed Rule	Final Rule
Very-low/Low	15	35
Low/High	100	200
High/Very-high	1,000	1,000

The study used to determine these thresholds is available on the regulations.gov Website (BLM Threshold Analysis).

One commenter stated that volume thresholds do not account for the fact that the economics of natural gas have changed with the Henry Hub wholesale price decreasing from $4 to $2/MMBtu, and therefore that the BLM's reliance on prices greater than $2/MMBtu is not reasonable. The BLM does not agree with this comment. First, natural gas prices are seasonal and $2/MMBtu gas is not permanent – for instance, the Henry Hub price can and does regularly exceed this level in response to cold weather under current market conditions. Second, it is unlikely that natural gas prices will remain at this $2/MMBtu level through the 3-year timeframe that the Threshold Analysis uses to determine the minimum payout volume for the very-low-/low-volume threshold or the 10-year timeframe that it uses to determine the low-/high-volume and high-/very-high-volume thresholds. The Energy Information Administration's (EIA's) Annual Energy Outlook for 2016[8] reference case projects average nominal Henry Hub wholesale prices of $3.79/MMBtu from 2016 to 2019, and $5.03/MMBtu from 2017 to 2026. Based on the foregoing, the BLM did not make any changes to the rule based on this comment.

Determining the FMP flow rate category

In the proposed rule, the BLM would have determined the FMP category by averaging the flow rate of that FMP over the previous 12 months or the life of the FMP, whichever was shorter. The BLM received several comments expressing concern about the proposed 12-month averaging period for FMPs that measure the flow rate from wells

---

[8] U.S., Energy Information Administration, Annual Energy Outlook 2016, *available at* http://www.eia.gov/forecasts/aeo/.

having high production-decline rates. Several of the commenters stated that as a result of the proposed 12-month averaging period, the operator would have to invest a lot of money to achieve the requirements for a high or very-high-volume FMP, only to have the volume drop to low- or even very-low-volume in a short period of time. One commenter recommended that the BLM should not include the first month of production in the average flow rate calculation.

The BLM agrees with the concept presented by the commenters and developed a definition for "averaging period" that applies to the category definitions in this rule and the uncertainty thresholds in the oil measurement rule (43 CFR subpart 3174). The definition, which appears in the subpart 3170 definitions section, retains a 12-month averaging period, but excludes any production from newly drilled wells prior to the second full month of production from the average calculation. In other words, if an FMP is installed to measure the production from a newly drilled well, and the well is put into production on May 10, the production reported in May and June would not be used in the calculation of average flow rate when determining the FMP's flow-rate category. In this example, May is not a full month of production; therefore, June is the first full month of production and July is the second full month of production. The 12-month averaging period starts with the July production figures.

The BLM received numerous comments asking for clarification on how an operator would determine the flow-rate category of an FMP. Some of the comments expressed confusion over the time period that the BLM would use to determine the average flow rate; whether this would be a 12-month average, a 6-month average, a daily rate, or based on previous-day flow rate available on the display of an EGM system. One commenter requested clarification on how an operator would determine the category if there were less than 12 months of data. The category definitions in the proposed rule and the new definition of “averaging period” in the final rule both specify that the average is taken over 12 months or the life of the FMP, whichever is shorter. The BLM did not make any further changes to the rule based on these comments. The BLM believes that the requirement for how the BLM will determine average flow rate is sufficiently clear under the definition of “averaging period” in subpart 3170.

Bias

The proposed rule defined “bias” as a shift in the mean value of a set of measurements away from the true value of what is being measured. In the final rule the BLM changed the word “shift” to “systematic shift” to better match other statistical definitions. The word “systematic” was also added to stress that bias is present if a shift in mean value occurs even after averaging repeated measurements of the value across the entire measurement system.

One commenter stated that the term “bias” as used in the proposed rule implies that the operator is intentionally causing a meter to read high or low. The BLM did not make any changes to the rule based on this comment because neither the definition nor the use of the word “bias” in the rule implies that any bias is intentional. “Bias” is a term of art in the measurement context and does not refer to underlying intent.

Uncertainty

The proposed rule did not define the term “uncertainty” and used both the terms “certainty” and “uncertainty” interchangeably. One commenter stated that there is no definition of “certainty” or “uncertainty” in proposed § 3175.10. Based on this comment the BLM used only the term “uncertainty” in the final rule, and included a definition for that term. The BLM made this change because “uncertainty,” unlike the term “certainty,” is a term that is commonly used and understood within the oil and gas measurement context. “Uncertainty” is defined to mean the range of error that could occur between a measured value and the true value being measured, calculated at a 95 percent confidence level. The BLM selected a 95 percent confidence level because it is commonly used in oil and gas measurement. A 95 percent confidence level means that the calculated uncertainty indicates the maximum amount of error that is expected to occur between the measured value and the true value being measured 95 percent of the time. There is a 5 percent chance that the risk of mismeasurement is greater than the calculated uncertainty.

Significant digit

The proposed rule defined “significant digit” as any digit of a number that is known with certainty. The definition was included in the proposed rule to support § 3175.104(a)(2), which required certain data in the QTR to be reported to five significant digits. Based on comments received, the requirement in the final rule was changed from five significant digits to a specified number of decimal places. Therefore, the definition of “significant digit” is no longer necessary and is deleted in the final rule.

Statistically significant and threshold of significance

Section 3175.10 of the proposed rule included definitions for “statistically significant” and “threshold of significance.” Because the final oil measurement rule (43 CFR subpart 3174) also uses these terms, the BLM moved the definitions to subpart 3170. The BLM did not make any changes to the definitions.

Heating value variability

The BLM added a definition of "heating value variability" to the final rule in response to numerous comments expressing confusion over what this term means and how the BLM would determine it. These comments are discussed under § 3175.31(b).

Other definitions

The BLM added a definition for "AGA Report No. (followed by a number)" to the final rule to be consistent with the definitions for GPA and API that pertain to standards incorporated by reference (see § 3175.30). The proposed rule did not incorporate any AGA (American Gas Association) standards; however, the final rule incorporates two AGA standards (AGA Report No. 3 (1985) and AGA Report No. 8 (1992)). As explained elsewhere in the preamble, the BLM incorporated standards from AGA Report No. 3 because the final rule includes grandfathering provisions (see § 3175.61) relating to meter tube construction that allow operators of grandfathered meters to meet the older standards in lieu of the latest API standards. AGA Report No. 8 was adopted because the BLM determined it was the more appropriate reference for the calculation of supercompressibility. In the proposed rule, the incorporation by reference was for API 14.2; both standards are identical in content.

There are numerous other terms that were defined in both the proposed rule and the final rule. These include, "as-found," "as-left," "atmospheric pressure," "Beta ratio," "British thermal unit," "configuration log," "discharge coefficient," "effective date of a spot or composite sample," "electronic gas measurement," "element range," "event log," "heating value," "integration," "live input variable," "mean," "mole percent," "normal flowing point," "quantity transaction record," "Reynolds number," "senior fitting," "standard cubic foot (scf)," "standard deviation," "transducer," "turndown," "type test," “upper range limit (URL),” and “verification.” The BLM did not receive any comments on these definitions and did not change any of these definitions from the proposed rule. One commenter stated that there is no definition of “AO,” “FMP,” “PA,” “PMT,” or “uncertainty” in proposed § 3175.10. The terms “AO,” “FMP,” “PA,” and “PMT” are defined under subpart 3170 because they apply to all the rules published under that part including subparts 3173, 3174, and 3175. Therefore, those definitions were not added to subpart 3175 in the final rule

§ 3175.20 – General requirements

Proposed § 3175.20 would have required measurement of all gas removed or sold from Federal or Indian leases and unit PAs or CAs that include one or more Federal or Indian leases to comply with the standards of the proposed rule (unless the BLM grants a variance under proposed § 3170.6). The BLM received a comment suggesting the requirements of § 3175 should only apply to those units or agreements above a set percentage of Federal interest. The BLM disagrees for the reasons discussed under the definition of the flow-rate categories and did not make any changes to this section based on this comment.

The BLM received another comment objecting to the proposed requirement to measure all gas on leases, pointing out that many times leases are part of units or CAs, and may have combined measurement points for multiple leases within these agreements. The BLM believes the commenter has misinterpreted the requirement. The final rule requires all gas removed or sold from Federal and Indian leases, unit PAs, or CAs to comply with 43 CFR subpart 3175. If a lease is part of a unit PA or CA, the measurement requirements in subpart 3175 apply only to the FMP where gas is removed or sold from the unit PA or CA. This is because the BLM considers unit PAs and CAs to be individual cases – comparable to large "leases" – with regards to measurement. As a result, operators do not have to measure the gas produced from individual leases within a CA or unit PA. Internal measurement points, such as those flagged by the commenter, that combine production from individual leases or wells within a CA or unit PA are not subject to this subpart, assuming they are not used to measure gas that is removed or sold from the unit PA or CA for purposes of royalty determinations. The BLM did not make any changes to the final rule based on this comment.

The BLM did make a change to this section based on an internal review of the wording in the proposed rule. The proposed rule stated that "Measurement of all gas removed or sold from Federal and Indian leases and unit PAs or CAs that include one or more Federal or Indian leases, must comply with the standards prescribed in this subpart, except as otherwise approved under § 3170.6 of this subpart." The BLM realized that this language does not account for situations where the BLM has granted commingling and allocation approval (CAA) under 43 CFR part 3173. Where the BLM has granted a CAA, the allocation meters are not considered FMPs and, therefore, do not have to comply with the requirements of this rule (see the definition of FMP under subpart 3173). As a result, gas will be removed or sold from the lease, unit PA, or CA without being measured in accordance with the standards in this rule, which is contrary to the language of the proposed rule. To address this, the BLM changed the wording of this sentence to "Measurement of all gas at an FMP must comply with the standards of this subpart…." It should be noted that if a gas allocation meter were to become an FMP in the future, it would have to comply with the applicable requirements of this rule.

§ 3175.30 – Incorporation by reference

This section previously appeared as § 3175.31 in the proposed rule, but based on edits made to the final rule, this section and final § 3175.30 have swapped places.

This final rule incorporates a number of industry standards, either in whole or in part, without republishing the standards in their entirety in the CFR, a practice known as incorporation by reference. These standards were developed through a consensus process, facilitated by the American Petroleum Institute (API), the American Gas Association (AGA), the Gas Processors Association (GPA), and the Pipeline Research Council International (PRCI) 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 §§ 3175.31 through 3175.125 of this rule. The legal effect of incorporation by reference is that the incorporated standards become regulatory requirements. With the approval of the Director of the Federal Register, this rule generally incorporates the current versions of the standards listed below. However, the BLM is also incorporating older versions of several standards due to the "grandfathering" of some existing equipment in the final rule

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 § 3175.31 of the rule, or 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 (4)). The language of incorporation in 43 CFR 3175.30 meets the requirements of 1 CFR 51.9. Where appropriate, the BLM has incorporated industry standards governing a particular process by reference and then imposes requirements that are in addition 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, AGA, GPA, and PRCI 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 also 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 GPA materials are available for inspection at the GPA, 6526 E. 60th Street, Tulsa, OK 74145; telephone 918-493-3872; https://gpsa.gpaglobal.org/. The AGA materials are available for inspection at the AGA, 400 North Capitol Street, NW, Suite 450, Washington, DC 20001; telephone 202-824-7000. The PRCI material is available for inspection at the PRCI, 3141 Fairview Park Dr., Suite 525, Falls Church, VA 22042; telephone 703-205-1600.

The following describes the API, GPA, APA, and PRCI standards that the BLM is incorporating by reference into this rule:

- API Manual of Petroleum Measurement Standards (MPMS) Chapter 14--Natural Gas Fluids Measurement, Section 1, Collecting and Handling of Natural Gas Samples for Custody Transfer; Seventh Edition, May, 2016 ("API 14.1"). This standard provides comprehensive guidelines for properly collecting, conditioning, and handling representative samples of natural gas that are at or above their hydrocarbon dew point.
- 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"). This standard provides engineering equations and uncertainty estimations for the calculation of flow rate through concentric, square-edged, flange-tapped orifice meters.
- API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 2, Specification and Installation Requirements; Fifth Edition, March 2016 ("API 14.3.2"). This standard provides construction and installation requirements, and standardized implementation recommendations for the calculation of flow rate through concentric, square-edged, flange-tapped orifice meters.
- API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 3, Natural Gas Applications; Fourth Edition, November 2013 ("API 14.3.3"). This standard is an application guide for the calculation of natural gas flow through a flange-tapped, concentric orifice meter.

- API MPMS Chapter 14, Natural Gas Fluids Measurement, Section 3, Concentric, Square-Edged Orifice Meters, Part 3, Natural Gas Applications, Third Edition, August 1992 ("API 14.3.3 (1992)"). This standard is an application guide for the calculation of natural gas flow through a flange-tapped, concentric orifice meter.
- API MPMS, Chapter 14, Section 5, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer; Third Edition, January 2009; Reaffirmed February 2014 ("API 14.5"). This standard presents procedures for calculating, at base conditions from composition, the following properties of natural gas mixtures: Gross heating value, relative density (real and ideal), compressibility factor, and theoretical hydrocarbon liquid content.
- API MPMS Chapter 21, Section 1, Flow Measurement Using Electronic Metering Systems--Electronic Gas Measurement; Second Edition, February 2013 ("API 21.1"). This standard describes the minimum specifications for electronic gas measurement systems used in the measurement and recording of flow parameters of gaseous phase hydrocarbon and other related fluids for custody transfer applications utilizing industry recognized primary measurement devices.
- API MPMS Chapter 22—Testing Protocol, Section 2, Differential Pressure Flow Measurement Devices; First Edition, August 2005; Reaffirmed August 2012 ("API 22.2"). This standard is a testing protocol for any flow meter operating on the principle of a local change in flow velocity, caused by the meter geometry, giving a corresponding change of pressure between two reference locations.

- GPA Standard 2166-05, Obtaining Natural Gas Samples for Analysis by Gas Chromatography; Adopted as a Tentative Standard, 1966; Revised and Adopted as a Standard, 1968; Revised 1986, 2005 ("GPA 2166-05"). This standard recommends procedures for obtaining samples from flowing natural gas streams that represent the compositions of the vapor phase portion of the system being analyzed.
- GPA Standard 2261-13, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography; Adopted as a Tentative Standard, 1961; Revised and Adopted as a Standard, 1964; Revised 1972, 1986, 1989, 1990, 1995, 1999, 2000 and 2013 ("GPA 2261-13"). This standard establishes a method to determine the chemical composition of natural gas and similar gaseous mixtures within set ranges using a gas chromatograph (GC).
- GPA Standard 2198-03, Selection, Preparation, Validation, Care and Storage of Natural Gas and Natural Gas Liquids Reference Standard Blends; Adopted 1998; Revised 2003. ("GPA 2198-03"). This standard establishes procedures for selecting the proper natural gas and natural gas liquids reference standards, preparing the standards for use, verifying the accuracy of composition as reported by the manufacturer, and the proper care and storage of those standards to ensure their integrity as long as they are in use.
- GPA Standard 2286-14, Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography; Adopted as a Standard 1995; Revised 2014 ("GPA 2286-14"). This method is intended for the compositional analysis of natural gas and similar gaseous

mixtures where precise physical property data of the hexanes and heavier fractions are required. The procedure is applicable for mixtures which may contain components of nitrogen, carbon dioxide, and/or hydrocarbon compounds C1-C14.

- AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Second Edition, September 1985 ("AGA Report No. 3 (1985)"). This standard provides construction and installation requirements, and standardized implementation recommendations for the calculation of flow rate through concentric, square-edged, flange-tapped orifice meters.
- AGA Report No. 8, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases; Second Edition, November 1992 ("AGA Report No. 8"). This standard presents detailed information for precise computations of compressibility factors and densities of natural gas and other hydrocarbon gases, calculation uncertainty estimations, and FORTRAN computer program listings.
- PRCI NX 19, Manual for the Determination of Supercompressibility Factors for Natural Gas; December 1962 ("PRCI NX 19"). This standard presents detailed information for computations of compressibility factors and densities of natural gas and other hydrocarbon gases.

Several commenters suggested that the BLM should adopt API and GPA standards in their entirety rather than incorporating only parts of them. Some of the commenters stated that the BLM should incorporate all of API MPMS Chapter 1 (Terms and Definitions), all of Chapter 14 (Natural Gas Fluids Measurement), all of Chapter 21 (Flow

Measurement Using Electronic Metering Systems), and all of Chapter 22 (Testing Protocols).

The BLM did not make any changes as a result of these comments. The rule incorporates five industry standards in whole and seven industry standards in part. API and GPA standards are written for industry to use as guidelines in designing and operating measurement facilities, generally for custody-transfer applications, were not designed for the regulatory environment, and present potential enforcement challenges and limitations. As such, these standards are often difficult to adopt without modification as regulations. The BLM can only enforce requirements that are objective, clearly defined, and relevant to the BLM's goal of ensuring accurate and verifiable measurement. Many of the API and GPA standards referenced by the commenters do not meet this threshold. For example, API 21.1, Section 6, sets standards for data availability. API 21.1, Subsection 6.2, requires, among other things, that onsite data include at least 7 days of hourly QTRs. While this may be a useful requirement for industry, the BLM is not concerned in this rule with how long data are maintained onsite. The FOGRMA of 1982 (as amended by the Royalty Simplification and Fairness Act of 1996) requires all records for Federal leases to be maintained for a period of 7 years from the date they are generated. Whether they are maintained onsite or offsite is irrelevant to the BLM's goals. In addition, it would be very difficult for BLM inspectors to enforce such a provision and it would serve no purpose for them to do so.

The following table lists the API standards that the commenters suggested the BLM should adopt and our response.

Chapter/	**Subject**	**Incorporated or Not Incorporated by**

Section/ Part		**the BLM**
1	Terms and definitions	Not incorporated. The definitions in this chapter may be different from the definitions the BLM requires due to the specific purpose of each definition in a regulatory context. In addition, this chapter contains definitions for all API standards, not just those relating to gas measurement.
14.1	Collecting and Handling of Natural Gas Samples for Custody Transfer	Incorporated by reference.
14.2	Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases	Incorporated by reference under AGA Report No. 8.
14.3.1	Orifice Metering of Natural Gas… Part 1: General Equations and Uncertainty Guidelines	Incorporated by reference.
14.3.2	Orifice Metering of Natural Gas… Part 2: Specification and Installation Requirements	Incorporated by reference.
14.3.3	Orifice Metering of Natural Gas… Part 3: Natural Gas Applications	Incorporated by reference.
14.3.4	Orifice Metering of Natural Gas… Part 4: Background, Development, Implementation Procedures and Subroutine Documentation	Not incorporated. Part 4 is only informational and does not contain any standards or requirements.
14.4	Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes	Not Incorporated. Has no relevance to the measurement of natural gas from Federal and Indian leases.
14.5	Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer	Incorporated by reference.
14.6	Continuous Density Measurement	Not incorporated. Applies to liquids and supercritical fluids.
14.7	Mass Measurement of Natural Gas Liquids	Not incorporated. Applies to liquid measurement.
14.8	Liquefied Petroleum Measurement	Not incorporated. Applies to liquid measurement.
14.9	Measurement of Natural Gas by Coriolis Meter	Not incorporated. Very little demand for gas Coriolis meters. May be used by the PMT in reviewing requests for Coriolis measurement.

14.10	Measurement of Flow to Flares	Not incorporated. If applicable laws or regulations make certain flared gas royalty bearing, such gas may be subject to the regulations found in subpart 3175 governing gas produced for sale. The PMT may also consider alternatives to orifice measurement for flare metering.
21.1	Flow Measurement Using Electronic Metering Systems – Electronic Gas Measurement	Incorporated by reference.
21.2	Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters	Not incorporated. Applies to liquid measurement.
22.1	General Guidelines for Developing Testing Protocols for Devices Used in the Measurement of Hydrocarbon Fluids	Not incorporated. Applies only to the development of subsequent sections under this chapter; has no regulatory relevance.
22.2	Testing Protocols – Differential Pressure Flow Measurement Devices	Incorporated by reference.
22.3	Testing Protocol for Flare Gas Metering	Not incorporated. If applicable laws or regulations make certain flared gas royalty bearing, such gas may be subject to the regulations found in subpart 3175 governing gas produced for sale. The PMT may also consider alternatives to orifice measurement for flare metering.
22.4	Testing Protocol for Transducers	Not yet published.
22.5	Testing Protocols for Flow-Computer Software	Not yet published.
22.6	Testing Protocols for Gas Chromatographs	Not incorporated. Draft standard was not available in time for the final rule; no comments supported incorporation of this standard.

Of the 22 standards in Chapters 1, 14, 21, and 22 that the commenters recommended for incorporation, the BLM is incorporating eight standards. Two of the remaining standards have not yet been published by API, four apply only to liquid measurement, and two are for informational uses only. The BLM did not incorporate the remaining six recommended standards because they are not relevant to royalty measurement, were not published in time to include in the final rule, or the BLM determined that they either had the potential to conflict with BLM requirements or did not help achieve the purposes of the rule or the underlying legal requirements.

One commenter stated that API 14.1 and GPA 2166 are clear and enforceable as written and should be incorporated in whole. The rule incorporates portions of these two standards. While there are portions of API 14.1 and GPA 2166 that are clear and enforceable as written, many parts of these standards are not. For example, API Chapter 14.1, Subsection 6.3.2.1 states: "Sample distortion due to chemical and physical adsorption can be minimized by prudent selection of sampling system materials. In general, materials and coatings that are chemically inert and of minimum porosity are the best choices." While this statement has important educational value, it would be virtually impossible for a BLM inspector to ascertain whether a sampling system material is in accordance with the standard or to take an enforcement action against an operator for not making a "best choice." The BLM did not make any changes to the rule based on this comment.

Several commenters suggested that the BLM should automatically incorporate the latest version of a standard rather than specifying a year and edition of the standard. The BLM did not make any changes to the rule based on these comments. To promulgate a rule, all Federal agencies must follow the APA, which establishes specific requirements for Federal agencies to follow. In general, the agency must provide notice to the public that a new rule is under consideration, publish a draft of the rule in the Federal Register, and provide the public an opportunity to comment on the proposed rule (see 5 U.S.C.

553). When the BLM incorporates a standard by reference, the standard becomes part of the rule in which it is incorporated.

If the rule were structured to incorporate “the latest version” of a particular standard, the requirements of the rule would automatically change whenever a particular standard is updated in the future. Changing a substantive rule in this manner, without the opportunity for public input, would be inconsistent with the notice-and-comment requirements of the APA, and therefore would not be legally permissible. The BLM will, however, evaluate new standards as they are issued by API, GPA, and others, and will determine if it is appropriate to initiate a rulemaking process to update the reference in subpart 3175 to incorporate the then-current version of those standards. In the interim, an operator could request a variance to follow the more recent version of a particular standard in lieu of the one incorporated by reference in this rule. Such requests would be evaluated by the PMT as outlined in this rule.

Several commenters suggested incorporating the latest version of GPA 2261-13, instead of GPA 2261-00. The BLM agrees with this comment and has changed the incorporation by reference to refer to the latest version of this standard. See the portion of the preamble that describes § 3175.118 for further discussion of these comments.

Several commenters suggested incorporating GPA 2286-14, relating to taking extended analyses. The BLM agrees with this comment and incorporated this standard by reference because § 3175.119(b) requires operators to do extended analyses in some instances. See the portion of the preamble that discusses § 3175.117 for further discussion of these comments.

As discussed in connection with § 3175.10, the BLM did incorporate two AGA standards in the final rule: AGA Report No. 3 (1985) and AGA Report No. 8. The BLM incorporated AGA Report No. 3 because the final rule includes meter tube construction standards for certain grandfathered facilities (see § 3175.61) in lieu of the latest standards in API 14.3.2. The BLM also changed the incorporation by reference for the calculation of supercompressibility. In the proposed rule the incorporation by reference was for API 14.2; however, this was changed to AGA Report No. 8 in the final rule because the BLM determined this was a more appropriate reference. Both standards are identical in content.

§ 3175.31 – Specific performance requirements

Note that the performance requirements appeared under § 3175.30 in the proposed rule. In the final rule, the BLM switched the provisions in §§ 3175.30 and 3175.31 for formatting purposes.

Section 3175.31 sets overall performance standards for measuring gas produced from Federal and Indian leases, regardless of the type of technology used. The performance standards provide specific objective criteria that the BLM can use to analyze meter systems not specifically allowed under the final rule. The performance standards also form the basis of determining the individual equipment standards that apply to each flow-rate class of meter (i.e., very-low, low, high, and very-high volume).

Section 3175.31(a) establishes limits on the maximum allowable flow-rate measurement uncertainty. Uncertainty indicates the risk of measurement error. For high-volume FMPs (flow rate greater than 200 Mcf/day, but less than or equal to 1,000 Mcf/day), the maximum allowed overall flow-rate measurement uncertainty is ±3 percent. For very-high-volume FMPs (flow rate of more than 1,000 Mcf/day), the maximum allowable flow-rate uncertainty is reduced to ±2 percent, because uncertainty in higher-volume meters presents greater royalty risks than in lower-volume meters. In addition, upgrades necessary to achieve an uncertainty of ±2 percent for very-high-volume FMPs will be more economical given these FMPs' higher overall production levels. Not only do the higher flow rates make these necessary upgrades more economical, many of the measurement uncertainty problems associated with lower-volume FMPs, such as intermittent flow, are not as prevalent with higher-volume FMPs.

The ±3 percent uncertainty requirement for high-volume FMPs is the same as what is currently required in all of the statewide NTLs for EFCs. However, the ±3 percent uncertainty requirement in the statewide NTLs applies to all FMPs measuring more than 100 Mcf/day. Section 3175.31(a), by contrast, applies only to high- (±3 percent) and very-high- (±2 percent) volume FMPs. Under the new rule, therefore, meters measuring between 100 Mcf/day and 200 Mcf/day are no longer required to meet an uncertainty standard. Consistent with the existing requirements of the statewide NTLs, meters measuring less than 100 Mcf/day are not subject to uncertainty requirements.

Section 3175.31(a)(3) specifies the conditions under which flow-rate uncertainty must be calculated. Flow-rate uncertainty is a function of the uncertainty of each variable used to determine flow rate. The uncertainty of variables such as differential pressure, static pressure, and temperature is dynamic and depends on the magnitude of the variables at a point in time. This section lists two sources of data to use for uncertainty determinations. The best data source for average flowing conditions at the FMP would be the monthly averages typically available from a daily QTR. However, daily QTRs are not usually readily available to the AO at the time of inspection because they must usually be requested by the BLM and provided by the operator ahead of time. If the daily QTR is not available to the AO, the next best source for uncertainty determinations would be the average flowing parameters from the previous day, which will be required under § 3175.101(b)(4)(i) through (iii) of this final rule (§ 3175.101(b)(4)(i) through (iv) of the proposed rule).

The BLM received numerous comments on this section. One commenter stated that the new performance requirements would cause wells to be shut in, although no support for that claim was included in the comment. The BLM conducted a detailed economic analysis to support the new flow category thresholds discussed under proposed § 3175.10, which included the costs of any upgrades necessary to meet the new uncertainty requirements (see the BLM Threshold Analysis). The flow-rate uncertainty of ±3 percent for high-volume FMPs is actually less restrictive than the current uncertainty requirement in the statewide NTLs for EFCs. The NTLs require an overall uncertainty of ±3 percent or better for all meters measuring more than 100 Mcf/day. The final rule expands that limit to 200 Mcf/day. Therefore, FMPs measuring between 100 Mcf/day and 200 Mcf/day, which would have been subject to the ±3 percent uncertainty limit under the statewide NTLs, are now exempt from any uncertainty requirement. The new uncertainty limit of ±2 percent for very-high-volume FMPs is only required for FMPs measuring more than 1,000 Mcf/day, which applies to just over 1 percent of all FMPs, according to data maintained by the BLM about current production. The BLM believes that a ±2 percent uncertainty will not be difficult to achieve on very-high-volume FMPs because the flow tends to be more stable and contain fewer liquids for wells producing at those levels. Additionally, for very-high-volume FMPs, any costs associated with achieving a

±2 percent uncertainty versus a ±3 percent uncertainty, such as the purchase of a new transducer, should not be significant given the overall magnitude of production. The BLM did not make any changes to the rule as a result of these comments.

Several commenters expressed a concern that reduced uncertainty will not necessarily increase revenue or royalty. Uncertainty is the risk of mismeasurement, and the goal of reducing uncertainty is to reduce that risk regardless of whether the end result is greater royalty, less royalty, or no change in royalty. Reducing the risk of mismeasurement ensures that the measurement is more accurate, which is one of the primary goals of this rule. As reflected in other provisions of this rule, the BLM has developed measurement standards that impose uncertainty requirements commensurate with the royalty risk posed by a particular facility. For these reasons, no changes to the rule were made.

One commenter stated that any increase in transportation costs, such as meter upgrades, would increase transportation allowances under the ONRR valuation regulations, thereby reducing royalty. The BLM has confirmed with ONRR that there are no circumstances under which an operator can claim expenses relating to measurement as a transportation allowance. The BLM did not make any changes to the rule based on this comment.

The BLM received several comments objecting to what they said is a lack of justification for the uncertainty limits in the proposed rule. The BLM does not agree with these comments. The preamble to the proposed rule provided a detailed explanation of how the BLM developed the uncertainty limits and why they were developed. The BLM did not make any changes to the final rule based on these comments.

The BLM will enforce flow-rate measurement uncertainty using standard calculations such as those found in API 14.3.1, which are incorporated into the BLM uncertainty calculator (www.wy.blm.gov), or other methods approved by the AO. BLM employees use the uncertainty calculator to determine the uncertainty of meters that are used in the field. However, existing and previous versions of the uncertainty calculator do not account for the effects of relative density uncertainty because these effects have not been quantified. The gas analysis data required in § 3175.120(e) and (f) of the final rule allow the BLM to quantify the relative density uncertainty by performing a statistical analysis of historical relative density variability and including it in the determination of overall measurement uncertainty, making these uncertainty calculations more robust.

The BLM received numerous comments stating that the BLM has not published the calculations used in the BLM uncertainty calculator, making it difficult to comment on the uncertainty calculation. The BLM disagrees with this comment. A user's manual and detailed description of every calculation used in the uncertainty calculator has been posted on both the BLM website (www.blm.gov/wy) and the Colorado Engineering and Experiment Station, Inc. website since December 2009. These are the only websites from which the BLM uncertainty calculator can be downloaded, and the link to download the documentation is immediately adjacent to the link to download the calculator. One commenter stated that these calculations must be published before mandating the use of the calculator. Neither the proposed rule nor the final rule mandates the use of the BLM uncertainty calculator. As discussed in the preamble, the BLM uncertainty calculator is a method by which BLM inspectors could enforce the uncertainty requirements; however, the calculator is not referred to anywhere in the regulation itself. The BLM did not make any changes to the rule in response to these comments.

The BLM received several comments stating that the BLM should have published the uncertainty calculations in the proposed rule and asked for clarification of what those calculations would be. The BLM agrees with this comment and incorporated by reference API 14.3.1, Section 12, which includes the uncertainty calculations that the BLM accepts and uses in the BLM uncertainty calculator. Section 3175.31(a)(4) was added to the final rule to reference the uncertainty calculations in API 14.3.1, Section 12.

Section 3175.31(b) establishes an uncertainty requirement for the measurement of heating value. This was included because both heating value and volume directly affect royalty calculation if gas is sold at arm’s length on the basis of a per-MMBtu price. Virtually all of the gas sold domestically in the United States is priced on a $/MMBtu basis. The royalty is computed by the following equation:

$$R = V \times HV \times P \times R_r,$$

where:

R = royalty owed, $;

V = volume of gas removed or sold from a lease, Mcf;

HV = heating value, MMBtu/Mcf;

P = gas value, $/MMBtu; and

R_r = royalty rate.

Thus, a 5 percent error in heating value would result in the same error in royalty as a 5 percent error in volume measurement.

The BLM recognizes that the heating value determined from a spot sample only represents a snapshot in time, and the actual heating value at any point after the sample was taken may be different. The probable difference is a function of the degree of variability in heating values determined from previous samples. If, for example, the previous heating values for a meter are very consistent, then the BLM would expect that the difference between the heating value based on a spot sample and the actual heating value at any given time after the spot sample was taken would be relatively small. The opposite would be true if the previous heating values had a wide range of variability. Therefore, the uncertainty of the heating value calculated from spot sampling will be determined by performing a statistical analysis of the historical variability of heating values over the past year for high- and very-high-volume FMPs. If an operator installs a composite sampling system or an on-line GC, the BLM will consider that device as having met the heating-value uncertainty requirements of this section.

The uncertainty limits for heating value are based on the annualized cost of spot sampling and analysis as compared to the royalty risk from the resulting heating-value uncertainty. The BLM used the data collected for the Gas Variability Study (see the discussion of § 3175.115 below) as the basis of this analysis. For high-volume FMPs, the BLM determined that the cost to industry of achieving an average annual heating-value uncertainty of ±2 percent by using spot sampling methods would approximately equal the royalty risk resulting from the same ±2 percent uncertainty in the heating value. For very-high-volume FMPs, an average annual heating-value uncertainty of ±1 percent would result in a cost to industry that is approximately equal to the royalty risk of the uncertainty. The rule therefore prescribes these respective levels as the allowed average annual heating-value uncertainty for high- and very-high-volume FMPs.

The BLM received numerous comments on this section stating that the new performance requirements would cause wells to be shut in, although no support for that claim was included in the comments. As with the volume uncertainties, the required heating-value uncertainties will only apply to FMPs measuring more than 200 Mcf/day. The BLM did not receive any data supporting the argument that meeting an average annual heating-value uncertainty of ±2 percent (high volume) or ±1 percent (very-high volume) would be so costly that an operator would shut in the well(s) flowing through the meter rather than complying with this requirement. Under the worst-case scenario for high-volume FMPs, where the heating value from the FMP is highly erratic from sample to sample, the maximum cost to the operator would be to take spot samples every 2 weeks, which represents a relaxation of requirements in the proposed rule that would have required weekly samples. The BLM Threshold Analysis included the cost of bi-weekly sampling in the determination of an appropriate threshold for the low-/high-volume categories. For very-high-volume FMPs, the worst-case scenario would require an operator to install a composite sampling system. The proposed rule would have also required on-line GCs or composite samplers for high-volume FMPs. The BLM Threshold Analysis includes this cost to determine the high-/very-high-volume threshold. The costs to comply with the heating-value uncertainties are not significant enough that a prudent operator would opt to shut in the well(s) flowing through FMPs producing at that level. Also, the operator has other means to reduce the heating-value variability from sample to sample, such as employing quality control measures in sampling and analysis.

Several commenters stated that there is no reason the heating-value uncertainty limits should be more restrictive than the flow-rate uncertainty limits. For flow rate, an uncertainty of ±3 percent for high-volume FMPs and ±2 percent for very-high-volume FMPs is required. For heating value, an average annual uncertainty of ±2 percent uncertainty for high-volume FMPs and ±1 percent uncertainty for very-high-volume FMPs is required. As described in the preamble and in the BLM Threshold Analysis, the BLM determined the uncertainties for volume and heating value separately based on cost of compliance versus royalty risk resulting from the uncertainty requirement. For example, the flow-rate uncertainty and costs associated with achieving that uncertainty are dependent on the size, quality, configuration, and operation of the primary, secondary, and tertiary devices. For heating value, the uncertainty and costs associated with achieving that uncertainty are a function of the heating-value variability and sampling frequency or sampling method (i.e., composite versus spot). Because the determinants of flow-rate uncertainty and heating-value uncertainty are independent, the costs of achieving specified uncertainty levels are also independent. As a result, the uncertainty limits for volume and heating value were set independently based on the results of the BLM Threshold Analysis. Generally, flow-rate uncertainty targets are more difficult and expensive to achieve than uncertainty targets for average annual heating value. For example, an average annual heating-value uncertainty of ±1 percent is achievable in most cases by simply increasing the sample frequency, which typically costs a few hundred dollars per year. By contrast, achieving a volume uncertainty of ±1 percent would, in most cases, require operators to purchase the most expensive transducers available and install separation and other equipment that would maintain a very consistent flow rate. This could cost tens of thousands of dollars or more. The BLM did not make any changes to the final rule based on these comments.

The BLM received several comments suggesting other uncertainty limits from those listed in the proposed rule. One commenter suggested that both the flow rate and heating-value uncertainties should be reduced to ±1 percent for high- and very-high-volume FMPs and an uncertainty requirement of ±5 percent should be added for very-low and low-volume FMPs. Another commenter suggested that the heating-value uncertainty should be ±7.5 percent when the heating value is above 1,200 Btu/scf and ±5 percent when the heating value is below 1,200 Btu/scf. Another commenter suggested that the BLM establish uncertainty levels for heating values by working with trade groups. Commenters submitted little rationale to support any of these suggested uncertainty levels. The BLM believes that the uncertainty levels given in the proposed rule are fair, reasonable, and achievable based on its experience in the field. They were established by determining the point at which the cost of compliance equals the risk to royalty. The BLM did not make any changes to the proposed rule based on these comments.

Several commenters stated that the BLM is confusing variability with uncertainty when establishing an uncertainty limit for average annual heating value. The BLM disagrees with these comments. The commenters appear to be assuming that the BLM used the term “uncertainty” interchangeably with “variability.” This is not the case, as described in detail in the BLM Gas Variability Study and as used in this rule. With respect to heating value, the term “variability” refers to the statistical variation from the mean heating value based on a certain number of previous gas analyses. For example, the heating values from five previous gas samples are shown in the table below, and the mean value of those five heating values is 1,256 Btu/scf. The variability of these five samples is the standard deviation of the five heating values (±14.3 Btu/scf) multiplied by the “student-t” function that yields a 95 percent confidence. For the five samples, the student-t function is 2.78, and the variability of this FMP is ±40 Btu/scf (±14.3 Btu/scf x 2.78), or ±3.2 percent of the average heating value. The BLM considers the variability a quasi-static property of the meter. The cause of the variability could be actual changes in gas composition over the time period analyzed, sampling technique, analysis technique, or other factors such as temperature at the time of sampling. Whatever the cause, this particular FMP has a variability of ±3.2 percent and will most likely continue to have a variability of approximately ±3.2 percent, unless something significant changes, such as the gas sampling or analysis technique or, for example, a new well is connected to the meter. When the BLM refers to heating-value uncertainty, it is specific to the average annual heating value uncertainty, not the uncertainty of an individual sample. The average annual heating value uncertainty is how close the average heating value from an FMP, as determined from gas samples taken over a 1-year time span, will be to the true average heating value of that FMP over the same time span. The true average annual heating value is a hypothetical value assuming the heating value was measured continuously over that year by an instrument with no uncertainty.

Date Taken	**Heating Value (Btu/scf)**
8/4/2014	1,255
2/18/2015	1,269
8/29/2015	1,251
3/2/2016	1,271
9/6/2016	1,236
Mean	1,256

In the BLM Gas Variability Study, the BLM determined the relationship between variability and uncertainty in the average annual heating value. The relationship is defined by the following equation:

$$U_{\overline{HV}} = 0.9510 V_{95\%} \sqrt{\frac{P_s}{365}},$$

where:

$U_{\overline{HV}}$ is the average annual heating-value uncertainty;

$V_{95\%}$ is the variability of previous heating values at a 95 percent confidence; and

P_s is the time between samples, days.

Although the variability of this FMP is ±3.2 percent, the average annual heating-value uncertainty is reduced by taking more samples over the year. In this example, the samples were taken twice per year, or roughly once every 180 days. Using the equation directly above, the uncertainty of the average annual heating value at this sampling frequency is reduced to ±2.1 percent. Sampling four times per year (every 90 days) would reduce the average annual heating-value uncertainty to ±1.5 percent. In summary, the average annual heating-value uncertainty requirement in the final rule governs uncertainty not variability. While variability is a factor in determining uncertainty, uncertainty can be reduced for a given level of variability by taking more frequent samples. The BLM added § 3175.31(b)(3) to the final rule as a result of these comments, in order to clarify and define the relationship between average annual heating-value uncertainty and variability. The equations presented in § 3175.31(b)(3) are the same equations that were presented in the heating value variability study repeatedly referenced in the preamble to the proposed rule. The study was also included in the supporting documentation posted on www.regulations.gov concurrently with the release of the proposed rule. In addition, § 3175.31(b)(3) allows the BLM to approve other methods of calculating average annual heating value uncertainty that operators or industry groups may develop.

One commenter asked that the BLM exempt central delivery point (CDP) meters from the heating-value uncertainty limits because achieving these limits would be difficult due to the constantly changing gas composition as different wells produce through the meter. The commenter provided an example of where a CDP meter, which would qualify as a very-high-volume FMP under the proposed rule, has a heating-value variability of ±3.5 percent. Assuming that the commenter determined the variability in the same manner as the BLM does, and took monthly samples at a very-high volume as required in the rule for the initial 1-year timeframe, the average annual heating-value uncertainty would be ±0.87 percent, based on the equation directly above, which is well within the uncertainty of ±1 percent required for very-high-volume FMPs. The BLM did not make any changes to the rule based on this comment.

Several commenters requested that the BLM provide the calculation methodology for average annual heating-value uncertainty. The BLM agrees with this comment and included the methodology in the final rule, under § 3175.31(b)(3). The methodology was also included in the BLM Gas Variability Study, which was posted as a supporting document on www.regulations.gov, along with the proposed rule.

One commenter stated that the cost of compliance for existing FMPs outweighs any measurable benefit. However, the volume cutoff points between low- and high-volume and between high- and very-high-volume FMPs in the final rule were established to represent the point at which the cost of compliance is equal to or less than the resulting reduction in royalty risk resulting from the improvements required by the rule. Royalty risk is the measurement uncertainty expressed in royalty dollars. The BLM did not make any changes to the rule based on this comment.

One commenter stated that the data used in the BLM Gas Variability study were not vetted or scrubbed to control for the conditions under which the samples were taken. The implication of the comment is that the BLM study is not statistically valid. While the BLM acknowledges that that the data were not controlled for the conditions under which they were taken, the data represent samples taken under real-life conditions and, in every case, the heating values used in the study were used as the basis for royalty payment. The BLM also believes that reliance on the study is appropriate without controlling for conditions because field sampling is typically not controlled to ensure that samples are taken at, for example, the same time of year or at the same ambient temperature – i.e., the study as used by the BLM for purposes of this rule is an accurate reflection of sampling results that occur in the field. The fact that the data showed no correlation existed between heating-value variability and pressure, temperature, or any of the other attributes analyzed demonstrates that other factors – perhaps poor sampling practices – are masking any correlation that theoretically should exist. Again, the BLM does not believe that scrubbing the data was necessary because the BLM does not intend to require the same conditions every time a sample is taken. In the field, it is impossible to control conditions, such as temperature, pressure, flow rate, separator efficiency, and other factors. The final rule establishes a uniform uncertainty value that reflects actual field practice. Based on the foregoing, the BLM did not make any changes to the rule based on this comment.

One commenter stated that the BLM Gas Variability Study does not reflect the accuracy of custody-transfer meters because most of the measurement points from which the BLM obtained the analyses were on-lease meters. The BLM believes that the commenter misunderstands the purpose of the study, which was to assess the variability of meters on which Federal and Indian royalty is based. These meters are often on-lease meters rather than custody-transfer meters on which the operator is paid. The BLM is not concerned with sales or custody-transfer meters that are not used in the determination of royalty. Therefore, the data used in the study are directly applicable to meters used for royalty determination, which are generally the on-lease meters. The BLM did not make any changes to the rule based on this comment.

Several commenters stated that composite samplers and on-line GCs are not economical on location because they do not work well with rich gas. The commenters did not supply any data to support this claim. Based on this comment and on the BLM Threshold Analysis, the BLM eliminated the provision in the proposed rule that would have required composite samplers or on-line GCs on high-volume FMPs, if the required ±2 percent average annual heating-value uncertainty could not be achieved by spot sampling. The BLM made this change for economic reasons, not because it accepts that these devices do not work well with rich gas. The BLM did not remove the provision in the rule that requires composite samplers on very-high-volume FMPs when the required ±1 percent average annual heating-value uncertainty cannot be achieved through spot sampling.

One commenter suggested that the determination of heating-value uncertainty should be on a field-wide basis rather than on a well or FMP basis. The commenter did not provide any data to substantiate this suggestion. The BLM does not agree with this comment. While the determination of heating-value uncertainty on a regional or formation-wide basis may seem like a reasonable approach, the data analyzed by the BLM (BLM Gas Variability Study) showed that heating-value variability is not correlated by region or formation. One possible reason for this is that the heating-value variability is not only dependent on the formation, but also on human factors, such as gas sampling and analysis techniques. The BLM did not make any changes to the rule in response to this comment.

Section 3175.31(c) establishes the degree of allowable bias in a measurement. Bias, unlike uncertainty, results in systematic measurement error; uncertainty only indicates the risk of measurement error. For all FMPs, except very-low-volume FMPs, no statistically significant bias is allowed. The BLM acknowledges that it is virtually impossible to completely remove all bias in measurement. When a measurement device is tested against a laboratory device, there is often slight disagreement, or apparent bias, between the two. However, both the measurement device being tested and the laboratory device have some inherent level of uncertainty. If the disagreement between the measurement device being tested and the laboratory device 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, apparent bias that is less than the uncertainty of the two devices combined is not considered to be statistically significant. This approach is consistent with existing BLM policy. Although bias is not specifically addressed in Order 5 or the statewide NTLs, the intent of those standards is to reduce bias.

The bias requirement does not apply to very-low-volume FMPs because very-low-volume FMPs are measuring such low volumes that any bias, even if it is statistically significant, results in little impact to royalty. The small amount of royalty loss (or gain) resulting from bias would be much less than the royalty lost if production were to cease altogether – a possible outcome if the operator were to decide that it is uneconomic to upgrade a meter to eliminate bias. Therefore, the BLM has determined that it is in the public interest to accept some risk of measurement bias in very-low-volume FMPs in order to maintain gas production. The BLM did not receive any comments on this section.

Section 3175.31(d) requires that all measurement equipment must allow for independent verification by the BLM. For example, if a new meter were 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 developed that used proprietary methods that precluded the ability to recalculate volumes or heating values, or made it impossible for the BLM to verify its accuracy, its use would also be prohibited. As explained in the preamble to the proposed rule, this is not a change from existing policy. Order 5 and the statewide NTLs for EFCs only allow meters that can be independently verified by the BLM.

One commenter stated that the performance goal of verifiability will restrict new technology. As an example, the commenter suggested that a verifiability requirement could have prevented the development of EGM systems. The BLM disagrees with this comment and did not make any changes to the rule as result. Contrary to the suggestion by the commenter, the BLM believes that verifiability is essential to making EGM systems universally accepted by both industry and regulators. For example, over 20 percent of the main body of API 21.1 is devoted to the audit trail, reporting, and data integrity required of EGM systems, all of which encompass verifiability.

One commenter expressed concern that the provisions of the proposed rule would cause the BLM to continually re-evaluate the quantity, rate, or heating value uncertainty of particular equipment. The BLM does not agree with this comment and did not make any changes to the rule as a result. The rule is designed to minimize required testing. The PMT will establish the uncertainty of each new piece of equipment one time, and operators can then rely on that determination in making the uncertainty calculations.

§ 3175.40 – Measurement equipment approved by standard or make and model

Section 3175.40 establishes the types, makes, and models of equipment and software versions that can be used at FMPs. All makes of flange-tapped orifice plates (§ 3175.41), all makes and models of mechanical recorders (§ 3175.42), and all makes and models of GCs (§ 3175.45) are automatically approved under this rule without any additional BLM review. This section also explains that for specific makes, models, and sizes of other types of equipment including transducers (§ 3175.43), flow-computer software (§ 3175.44), flow conditioners (§ 3175.46), differential primary devices other than flange-tapped orifice plates (§ 3175.47), linear measurement devices (§ 3175.48), and accounting systems (§ 3175.49) are approved for use at FMPs under the conditions and circumstances stated in those sections.

For the specified types of equipment requiring BLM approval, as explained in the section-specific discussions of this preamble, this rule requires that equipment must be reviewed by the PMT and approved by the BLM. The PMT, which consists of a team of measurement experts, will base its review of such equipment on data submitted by individual operators, companies, or equipment manufacturers. Unlike the variance process under Order 5, which limits approvals to specific facilities, and requires that operators submit separate requests to use the same equipment at different facilities, this final rule provides that once the PMT reviews and the BLM approves a piece of equipment or measurement process, that approval will be posted to the BLM website (www.blm.gov), and any operator may rely on that approval at any facility, provided the operator follows any attached conditions of use. The PMT process provides a way for the BLM to approve new technology without having to update its regulations, issue other forms of guidance (such as NTLs) or grant approvals on a case-by-case basis.

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.

The BLM received many comments that expressed concerns over the role, authority, staffing, process, and approval timeframes relating to the PMT. Several comments stated that the PMT should include industry members, academia, tribal members, and State Government representatives. Comments also stated that the PMT should be chartered under the Federal Advisory Committee Act (FACA) and that all meetings should be open to the public. The BLM finds formalizing the PMT and requiring a FACA-chartered committee to be inconsistent with expediting the approval of new and existing technology. As described in the final rule, the PMT will consist of measurement experts within the BLM whose primary job function is to review test data for new and existing technology and recommend approval or denial of that technology to the BLM. While the team has not yet been assembled, the BLM believes that once the PMT is fully staffed, reviews will take 30 to 60 days, assuming that the proper testing has been done and all pertinent data have been submitted to the PMT.

Under a FACA charter, as favored by some commenters, reviews would take much longer, possibly even years. A FACA charter first requires all members to be vetted and approved by the Secretary. The BLM would then have to publish a notice in the Federal Register of all meetings at least 30 days in advance. The BLM does not believe that this is an appropriate forum to review large amounts of test data and perform specialized analysis to determine if a device can meet the performance goals of the rule.

Substantively, the PMT's role in reviewing specific makes and models of equipment and making recommendations to the BLM for approval of particular equipment under this rule is similar to the authority for a BLM field office to issue variances under the existing Onshore Orders. The only difference between the existing variance process and the PMT is that under the existing variance process reviews are performed at the field-office level on a case-by-case basis; under this final rule these reviews will be performed once by a single entity at the Washington-Office level. Ultimately, the PMT makes recommendations for approval, and the BLM retains full discretion to concur with or reject such recommendations. In the final rule to update and replace Order 3, § 3170.8 has been revised to add a new paragraph (b) that addresses the appeals procedure for PMT recommendations that are approved by the BLM. The BLM did not make any changes to the rule based on these comments.

Other commenters stated that the rule should provide for administrative review of all recommendations made by the PMT. The BLM agrees with this comment and has added an administrative review to the PMT process as part of the final rule updating and replacing Order 3 (see 43 CFR 3170.8(b)). Under this process, any approval or denial made by the BLM based on a PMT recommendation can be administratively appealed to the Assistant Secretary for Lands and Minerals, or their designee. Using the analogy of the existing field office variance review process discussed earlier, the approval or denial of a variance for new technology under the current process could be appealed by anyone adversely affected by that approval or denial. Likewise, any decision made by the BLM regarding technology reviewed by the PMT is also subject to appeal by anyone adversely affected by that decision.

Several commenters said that the PMT would favor large companies that could afford elaborate "Cadillac" proposals. The BLM disagrees with this comment and did not make any changes as a result. The reviews performed by the PMT are not exclusive. In other words, if a large operator submitted a "Cadillac" proposal to the PMT and a small operator submitted a "Chevy" proposal (simple and inexpensive) to the PMT, the PMT would review both proposals on their merits. If the PMT and then, ultimately, the BLM determined that both proposals met the performance goals in this rule, then both proposals would be approved and posted on the BLM website. Once posted, any operator could use either the “Cadillac” or “Chevy” technology without any further approval needed.

One commenter stated that the PMT should develop testing manuals that the industry could follow. While the BLM did not make any changes to the rule based on this comment, the BLM agrees that manuals could provide useful guidance. Once formed, the PMT will consider developing nonbinding testing manuals, as suggested by the commenter.

One commenter stated that the PMT role should include the review of new gas sampling technology. The BLM agrees with this comment, but does not believe a change to the regulations is necessary. While this is not a specific function of the PMT listed under § 3175.40, the BLM believes that the PMT could consider reviewing new gas sampling techniques under the PMT’s general authority to review new measurement equipment and methods.

Several commenters objected to the lack of information in the proposed rule regarding the PMT review and approval process and also objected to the absence of a list of approved equipment published in the proposed rule. The BLM did not make any changes to the rule based on these comments. As a procedural matter, the BLM does not believe that it is necessary or appropriate to set forth prescriptive procedures for the PMT to follow in either the proposed rule or the final rule in order to preserve the BLM’s discretion in setting up this new entity. That said, the BLM notes that the rule is not silent on the PMT’s review procedures. To the contrary, the rule establishes specific performance standards and requirements that equipment and methods used for gas measurement must meet. This information was clearly identified in the proposed rule, and, for the most part, has been carried forward into the final rule.

The BLM did not publish a specific list of approved equipment because no such list exists. However, the rule does provide for the automatic acceptance of certain types of equipment, such as flange-tapped orifice plates, gas chromatographs, and mechanical recorders at low- and very low-volume FMPs. The PMT will develop the list of other types of approved equipment, such as flow conditioners and differential-pressure meters, based on a review of the data that the PMT receives and a determination by the PMT that the equipment complies with the performance standards established in this rule. The need for these reviews is the reason why the final rule establishes a 2-year phase-in period for equipment approved by the PMT in order to give the PMT time to complete this work.

One commenter questioned why the BLM is entering the free market by limiting the types of devices that operators can use. The BLM is not limiting the types of devices. To the contrary, an operator can use a variety of devices as long as those devices meet the applicable performance standards specified in the rule. The BLM believes that the only way to ensure that volume and quality measurement meets the specified uncertainty performance goals is to ensure that the components that contribute to volume and quality uncertainty have been tested in a consistent and transparent manner. The BLM did not make any changes to the rule based on this comment.

One commenter asked for clarification if the BLM is approving equipment by performance or uncertainty. Although the BLM is unclear as to what the commenter means by “performance” and “uncertainty” (uncertainty is a performance goal in this rule), the answer is case-specific as indicated below:

- Transducers (§ 3175.43): Approval for transducers installed at FMPs after the effective date of the rule is granted if the transducer undergoes the tests required in the testing protocol (see § 3175.130). Alternatively, for existing transducers, the BLM will grant approval if the manufacturer supplies the BLM with a sufficient amount of existing data. In either case, the BLM will ascertain the uncertainty of the transducer and how outside conditions, such as ambient temperature, affect the device.
- Flow-computer software (§ 3175.44): Approval is granted if the flow-computer software agrees with the reference software within a specified tolerance.
- Isolating flow conditioners (§ 3175.46): Approval is granted if the device is tested under API 14.3.2, Annex D, which includes a pass-fail criterion.
- Differential primary devices other than flange-tapped orifice plates (§ 3175.47): Approval is granted if the device is tested in accordance with API 22.2. The BLM will ascertain the uncertainty of the device and how factors such as installation configurations, Reynolds number, and differential-pressure-to-static-pressure-ratio, affect the device.
- Linear meters (§ 3175.48): Approval is granted if the BLM determines that the meter can meet or exceed the performance goals of § 3175.31(a), (c), and (d).
- Accounting systems (§ 3175.49): Approval is granted if the BLM determines that the system can meet the performance goals of § 3175.31(d).

The BLM did not make any changes to the rule based on this comment.

§ 3175.41 – Flange-tapped orifice plates

Flange-tapped orifice plates have been rigorously tested and have proven capable of meeting the performance standards of § 3175.31(a), (c), and (d). As such, FMPs using flange-tapped orifice plates that are installed, operated, and maintained as the primary device in accordance with the standards in §3175.80 are automatically accepted under the final rule with no additional review or approvals needed. The BLM did not receive any comments on this section.

§ 3175.42 – Chart recorders

Mechanical recorders have been in use on gas meters for more than 90 years in custody-transfer applications and their ability to meet the performance standards of § 3175.31(c) and (d) is well established. Because mechanical recorders are limited to very-low-volume and low-volume FMPs under the rule, they do not have to meet the uncertainty requirements of § 3175.31(a). As such, low- and very-low-volume FMPs using mechanical recorders that are installed, operated, and maintained in accordance with the standards in § 3175.90 are automatically accepted under the final rule with no additional review or approvals needed. The BLM did not receive any comments on this section.

§ 3175.43 – Transducers

While EGM systems are widely accepted for use in custody-transfer applications, there are currently no standardized protocols by which transducers, a critical component of an EGM system, are tested to document their performance capabilities and limitations. Proposed § 3175.43 would have required transducers to be tested under the protocols in § 3175.130 in order to be used at high- or very-high-volume FMPs. Transducers used at very-low and low-volume FMPs are not subject to these requirements. The primary purpose of the testing protocol is to determine the uncertainty of the transducer under a variety of operating conditions. Because very-low and low-volume FMPs are not subject to the uncertainty requirements under § 3175.31(a), testing the performance of the transducers used at these FMPs is unnecessary.

Several commenters requested that the BLM accept transducers currently in use or approve these transducers if the manufacturer can provide test data consistent with industry practice. The BLM agrees with these comments and added the option of using the test data the manufacturers used to derive their published performance specifications. However, if the data submitted by the manufacturer are incomplete, or insufficient to justify the published performance specifications, the BLM may use performance specifications derived by the PMT from the data, or limit the use of the transducer to specific ranges of pressure, temperature, or operating conditions.

The BLM received numerous comments suggesting that the BLM should accept published API-type testing standards for transducers in lieu of the protocols in the proposed rule. However, there are no API standards in place for testing transducers. The BLM is aware that the API is developing testing protocols for transducers, but these standards have not been published. The BLM did not make any changes to the rule based on these comments.

Numerous commenters suggested that the BLM should grandfather existing transducers from the type testing requirements in this section. The reasons given in the comments include the inability to type test older equipment that is no longer manufactured or supported by the manufacturer, the opinion that there is no need to test equipment that is properly working, the lack of laboratories equipped to do the testing, and timeframes for the PMT to review and approve existing equipment to avoid shutting in production. The proposed rule would have required type testing of all transducers used on high- and very-high-volume FMPs. The BLM recognizes these concerns and has made two changes in this section as a result. First, the requirement to use type-tested equipment will not take effect until 2 years after the effective date of the rule as provided in § 3175.60(a)(4) and (b)(2). This should be adequate time for the formation of the PMT, testing of existing equipment, and review of that equipment by the PMT. Second, for existing transducers, the BLM will allow operators or manufacturers to submit the data on which the manufacturer's published performance specifications are based, in lieu of using the testing protocols specified in § 3175.130 of the rule. This will allow the PMT to review, and the BLM to approve if appropriate, existing transducers without the need for additional testing. Additional changes based on these comments are addressed in the § 3175.130 discussion in this preamble.

Several commenters expressed a concern about the cost of replacing existing transducers as a result of this requirement. The BLM does not believe that this requirement would require operators to replace existing transducers. In addition to the 2-year implementation of this requirement and the provision to allow operators and manufacturers to submit existing data instead of generating new data, the transducer testing protocol in § 3175.130 is not a pass-fail requirement. The purpose of the testing protocol is to independently define the performance of a transducer and then use that performance to determine compliance with the overall uncertainty requirements in § 3175.31(a). The BLM did not make any changes to the rule based on these comments.

One commenter suggested that instead of approving transducers by make and model using the testing protocol, the BLM should just specify performance goals. The BLM has, in fact, specified performance goals for both volume (§ 3175.31(a)) and heating value (§ 3175.31(b)) based on overall measurement uncertainty. However, in order to enforce an uncertainty standard, BLM inspectors must be able to calculate the overall uncertainty to determine if the FMP meets the requirements. Transducer performance is often the largest contributor to overall volume measurement uncertainty, especially in situations where the transducer is operated at the low end of its upper calibrated limit. Currently, the BLM uncertainty calculator uses the manufacturer's published performance specifications in the calculation of uncertainty; however, there is no standard method that manufacturers use to develop those specifications. In addition, most manufacturers consider their testing process and data as proprietary, making it impossible for the BLM to verify. The BLM believes that to enforce an uncertainty performance goal, the components that go into the uncertainty calculation must be determined in a transparent and consistent manner. Therefore, the BLM did not make any changes to the rule based on this comment.

Two commenters also suggested that the BLM could use field calibration data to validate existing equipment. While the BLM believes that field calibration could be used to validate existing equipment, it would be difficult to extract individual installation effects from the data such as ambient temperature effects, vibration effects, and static pressure effects. In addition, it would be difficult to filter the data to eliminate human error in the calibration data. The BLM did not make any changes to the proposed rule as a result of these comments.

One commenter stated that operators have no economic incentive to replace existing transducers. The BLM did not make any changes to the rule based on this comment for two reasons. First, as explained previously, the testing protocols for transducers and flow computers would not generally require replacing existing equipment. Second, we agree that operators often do not have an economic incentive to replace existing transducers (in other words, the investment in a new transducer would not necessarily result in increased revenue). If they had an economic incentive, this provision in the rule would probably not be necessary. The intent of the provision is to improve accuracy and verifiability to ensure that the public and Indian tribes and allottees receive their fair share of the value of oil and gas resources extracted from their land. The BLM did not make any changes to the rule based on this comment.

§ 3175.44 – Flow-computer software

As with transducers, there are currently no standardized protocols by which flow-computer software is tested to document its capability to perform all calculations within acceptable tolerances and record and store other supporting information. Proposed § 3175.44 would have required flow-computer software at all FMPs to be tested under § 3175.140 in order to be used at an FMP.

Numerous commenters suggested that the BLM should grandfather existing flow-computer software versions from the type-testing requirements of this section. The commenters stated that it would be difficult to test software versions on older computers that are no longer supported by the manufacturer. Other commenters stated that the time required for the PMT to review and approve software versions could lead to production shut-ins.

The BLM recognizes these concerns and has made two changes in the final rule as a result. First, the requirement to use type-tested software does not take effect until 2 years after the effective date of the rule, as provided for in § 3175.60(a)(4) and (b)(2). This should be adequate time for the formation of the PMT, testing of existing software versions, review of that software by the PMT, and approval of the software by the BLM. Second, under the final rule, all software versions used at very-low- and low-volume FMPs are approved for use without testing, unless otherwise required by the BLM (§ 3175.44(c)). While this is not the complete grandfathering requested by the commenters, the BLM believes that there are very few older, unsupported flow computers in use at high- or very-high-volume FMPs.

The BLM received numerous comments suggesting that the BLM should accept published API type-testing standards for flow-computer software in lieu of the protocols in the rule. However, there are no API standards in place for flow-computer software. The BLM is aware that the API is developing testing protocols for flow-computer software, but these standards have not been published. The BLM did not make any changes to the rule based on these comments.

Several commenters expressed a concern about the cost of replacing existing flow computers as a result of this requirement. The BLM does not believe that this requirement requires operators to replace existing flow computers. The testing protocol defined in § 3175.140 applies to the software in the flow computer, not the flow computer itself (although the software testing is specific to individual makes and models of flow computers). The flow-computer testing protocol is a pass-fail requirement.

However, if the BLM discovers a software version that did not pass, the remedy would be to update the software and install it in the flow computer.

§ 3175.45 – Gas chromatographs

GCs have been rigorously tested and used in industry for custody-transfer applications, and their ability to meet the requirements of § 3175.31 has been demonstrated. Therefore, the rule allows all makes and models of GCs in determining heating value and relative density as long as they meet the requirements of §§ 3175.117 and 3175.118. The BLM did not receive any comments on this section.

§ 3175.46 – Isolating flow conditioners

Section 3175.46 requires all makes and models of flow conditioners used in conjunction with flange-tapped orifice plates at FMPs to be tested under established API test protocols, reviewed by the PMT, and approved by the BLM.

The final rule references API 14.3.2, Annex D, which provides a testing protocol for flow conditioners. In the proposed rule, based on the BLM's experience with other testing protocols, the BLM proposed using additional testing beyond what Annex D requires to meet the intent of the uncertainty limits in § 3175.31(a). Additional testing protocols would have been posted on the BLM's website at www.blm.gov. Numerous commenters expressed concern over the PMT's ability to include additions to the API 14.3.2 Annex D testing protocol for flow conditioners. The BLM agrees with these comments as they relate to flow conditioners and deleted the provision that would have allowed the PMT to add additional testing for flow conditioners.

One commenter asked if data for existing flow conditioners that have already been tested under Annex D will have to be resubmitted to the PMT to get approval. The PMT will require the data in order to review the flow conditioner in question. No changes to the rule were made as a result of this comment.

One commenter suggested that in lieu of establishing a new process for the PMT to follow for the approval of flow conditioners, the BLM should incorporate and use API Chapter 12.1. The commenter also stated that unless the PMT meets regularly, it will slow down the adoption of new technology. API 12.1 deals with the calculation of static petroleum liquids in upright cylindrical tanks and rail cars, which does not seem relevant here. The BLM's intent is to establish the PMT as a permanent full-time team dedicated to reviewing test data and performing other centralized measurement functions. The BLM did not make any changes to the rule based on this comment.

§ 3175.47 – Differential primary devices other than flange-tapped orifice plates

Section 3175.47 requires all makes and models of differential primary devices other than flange-tapped orifice plates to be tested under established API test protocols, reviewed by the PMT, and approved by the BLM in order to be used at FMPs.

This section references API 22.2 (2005), which establishes a testing protocol for differential devices. The proposed rule would have allowed the BLM to include additional testing requirements beyond those in the current version of API 22.2 to help ensure that tests are conducted and applied in a manner that meets the intent of § 3175.31 of this rule. The BLM would have posted any additional testing protocols on its website at www.blm.gov.

Numerous comments expressed concern over the PMT's ability to include additions to the API 22.2 testing protocol for differential primary devices. The BLM agrees and modified this provision accordingly.

Several commenters asked that the burden of testing new devices be on the manufacturer and not the operator. The BLM is not concerned with who does the testing. However, this section of the proposed rule specified that the operator must test these devices. The BLM agrees that the both the testing and the submittal of data to the PMT can be done by either the operator or the manufacturer; the BLM changed the reference to "operator" in this section to "operator or manufacturer" as a result of this comment.

§ 3175.48 – Linear measurement devices

Proposed § 3175.48 would have allowed the BLM to approve linear measurement devices reviewed by the PMT on a case-by-case basis to be used at FMPs. Linear measurement devices include ultrasonic meters, Coriolis meters, and turbine meters.

The BLM received numerous comments stating that linear meters should be approved on a type-testing basis, and not just on a case-by-case basis as stated in the proposed rule. The comments indicated that industry widely accepts linear meters and case-by-case approval could inhibit technological development. In addition, the commenters stated that there are existing industry standards for linear meters such as ultrasonic meters, turbine meters, and Coriolis meters. The BLM agrees with these comments and changed the wording of § 3175.48 from a "case-by-case basis" to a "type-testing basis," similar to the requirements for other devices under § 3175.40. When the PMT receives a request to use a linear meter, it will review any applicable standards for that meter as part of the approval process. The PMT will then recommend approval or denial of that device to the BLM. If the BLM approves the device, it will be posted at www.blm.gov.

One commenter expressed concern with the language in the proposed rule stating that the BLM "may," but does not have to, approve the make and model of a linear measurement device. The commenter indicated that this could present a regulatory hurdle that could delay the use of more technologically advanced devices like ultrasonic meters. Although the language of this section was changed based on other comments and the word "may" no longer appears, the BLM retains the discretion of approving or not approving certain makes and models of linear measurement devices based on the review of the PMT. The BLM does not agree that this will present a regulatory hurdle for the implementation of new technology. Instead, the BLM believes that having a consistent and thorough review process that ensures that the new technology can meet the uncertainty, bias, and verifiability goals of the rule will encourage acceptance of new technology that can meet these goals. The BLM did not make any changes to the rule based on this comment.

§ 3175.49 – Accounting systems

Accounting systems were not included in the proposed rule; however, the BLM received several comments on § 3175.104(a), (b), and (c) recommending that the BLM include the PMT review of accounting systems in the final rule. Paragraphs (a), (b), and (c) of § 3175.104 require operators to retain and submit to the BLM upon request original, unaltered, unprocessed, and unedited QTRs, configuration logs, and event logs. The BLM agrees with the comments and believes that the PMT should approve accounting systems by software version through a type-testing protocol. As a result, the final rule contains a protocol by which the PMT can assess whether an accounting system produces original, unaltered, unprocessed, and unedited records that can be submitted to the BLM.

When performing a production review, the BLM typically starts by sending a written order to the operator requiring the operator to submit data supporting the reported production quality and quantity over a specified time period and for a specified lease, CA, or unit PA. These data typically include QTRs, configuration logs, event logs, and alarm logs. As discussed in the preamble to the proposed rule, it is common practice for operators to submit these data to the BLM using third party software that automatically compiles data from the flow computers and uses it to generate a standard report. However, the BLM has found in numerous cases that the data submitted from the third-party software is not the same as the data generated directly by the flow computer. In addition, the BLM consistently has problems verifying the volumes reported through reports generated by third-party software.

As a result, the BLM has developed the testing protocol required in this section that compares raw data retrieved directly from flow computers to both edited and unedited data obtained from the third party software under test. The BLM will only approve software packages where the protocol demonstrates that the original, unaltered, unprocessed, and unedited data from the flow computer is provided by the software, and that edited data is clearly marked as such.

§ 3175.60 – Timeframes for compliance

Section 3175.60 provides a timeframe for when all measuring procedures and equipment installed at any FMP must comply with the requirements of this subpart. Proposed § 3175.60(a) would have required all meters installed after the effective date of the final rule to meet the requirements of the rule. The BLM received several comments stating that the requirement to enter all gas analyses into the GARVS (see § 3175.120(f)) should be delayed because GARVS does not exist yet and the BLM did not provide enough information about GARVS in the proposed rule for operators to develop reporting formats. GARVS is a new database that the BLM is developing as part of the implementation of this rule that will have the ability to receive gas analysis reports from operators. One commenter stated that the BLM should delay this requirement up to 7 years, to give operators enough time to obtain GC models that are capable of meeting the proposed GC requirements of § 3175.118. Several other commenters suggested a delay of 2 years. The BLM agrees with the latter comments and included a 2-year phase-in period for reporting into GARVS in the final rule (§ 3175.60(a)(2)). The 2-year phase-in period is to allow the BLM time to develop the GARVS software. Based on changes in the final rule relating to GCs, the BLM believes that virtually all existing GCs will meet the standards of this rule and that no additional delay to develop new GCs is necessary. The final rule (§ 3175.60(a)(3)) also delays the implementation of variable sampling frequencies in § 3175.115(b) for 2 years. In order to implement this requirement, GARVS must be fully functioning.

Numerous comments suggested that the BLM should grandfather existing equipment from having to get approval from the PMT. The commenters expressed concern over having to shut in wells while the PMT reviews and approves existing equipment. The proposed rule would have required type testing of transducers used on high- and very-high-volume FMPs and type testing of flow-computer software, flow measurement devices, and flow conditioners at all FMPs. The BLM understands these concerns and has made two changes in the rule as a result. First, the requirement to use equipment reviewed by the PMT and approved by the BLM will not take effect until 2 years after the effective date of the rule (§ 3175.60(a)(4)). This should be adequate time for the formation of the PMT, testing of existing equipment, and review and approval of that equipment by the PMT. Second, for existing transducers, the BLM will allow operators or manufacturers to submit the data on which their published performance specifications are based in lieu of using the testing protocols specified in § 3175.130 of the rule. This will allow the PMT to approve existing transducers without the need for additional testing.

Section 3175.60(b) sets timeframes for compliance with the provisions of this rule for measuring procedures and equipment existing on the effective date of the final rule. The timeframes for compliance generally depend on the average flow rate at the FMP. Under the proposed rule, very-high-volume FMPs would have had 6 months from the effective date of the rule, high-volume FMPs would have had 1 year from the effective date of the rule, low-volume FMPs would have had 2 years from the effective date of the rule, and very-low-volume FMPs would have had 3 years from the effective date of the rule. Higher-volume FMPs would have had shorter timeframes for compliance under the proposed rule because they present a greater risk to royalty inaccuracy than lower-volume FMPs and the costs to comply could be recovered in a shorter period of time.

Numerous comments stated that the compliance timeframes in the proposed rule were too short for several reasons, including the time it takes to revise accounting systems to handle the 11-digit FMP number; the time for budgeting, engineering, purchasing, and installing new equipment; the fact that GARVS is not yet up and running; and the time it will take for the PMT to approve existing equipment. In addition, several commenters stated that the proposed rule would have created a high demand for items such as flow computers and meter tubes that would comply with the new requirements, and that demand would delay the availability of the equipment. One commenter stated that the proposed timeframes also needed to consider delays caused by weather and seasonal restrictions in some areas. Commenters' suggestions ranged from a 1-year to a 3-year phase-in period or tying the phase-in period to when the FMP is approved by the BLM. One commenter suggested tying the phase-in period to the availability of GCs capable of meeting the new requirements in the proposed rule, although it is not clear to what new requirements the commenter was referring. The BLM generally agrees with these comments and changed the compliance timeframe for very-high-volume FMPs from 6 months to 1 year to coincide with the timeframe for high-volume FMPs. The compliance timeframe for very-low and low-volume FMPs remains at 3 years and 2 years, respectively. This change, in conjunction with other changes to the rule listed below, should alleviate the concerns raised by the commenters:

- Elimination of the need to display the 11-digit FMP number, or include this number in accounting systems (§§ 3175.101(b)(4)(i) and 3175.104(a)(1) in the proposed rule). Removing the requirement for FMPs to display the FMP number or run the latest API calculations should significantly reduce the number of FMPs that would potentially have been replaced under the proposed rule. Removing the requirement that accounting systems have to include the FMP number should reduce the amount of time required to modify accounting systems.
- Grandfathering of existing meter tubes at low- and high-volume FMPs (§ 3175.61(a)). Under the final rule, operators of existing very-low-volume, low-volume, and high-volume FMPs will not have to upgrade the meter tubes to API

14.3.2 standards. The BLM believes that meter tubes at very-high-volume FMPs constructed after API 14.3.2 was issued in 2000 meet those standards and will not have to be retrofitted. As with the flow computers, therefore, only those very-high-volume FMPs that were constructed prior to 2000 will require meter tube upgrades. The BLM believes that most meter tubes at very-high-volume FMPs were constructed to the latest API standards and will not have to be retrofitted as a result.

- Allowing existing data to approve transducers at high- and very-high-volume FMPs (§ 3175.43(b)). Under the final rule, operators can submit existing test data to the PMT in lieu of performing the testing under § 3175.130, for transducers that are in use at FMPs prior to the effective date of the rule. This will dramatically reduce the time and cost that could have been associated with the required testing for all transducers under the proposed rule.
- Modifying GC requirements (§§ 3175.113 and 3175.118). The BLM made numerous changes to §§ 3175.113 and 3175.118 relating to GCs, and believes that these changes address the concerns of the commenter who suggested that the BLM tie the timeframes to the availability of GCs capable of meeting the new BLM requirements. For example, the requirement under § 3175.118(b) of the proposed rule would have required samples to be analyzed until 3 consecutive runs are within the repeatability standards listed in GPA 2261-00, Section 9. It would have been very difficult for existing GCs to meet this proposed standard and, as a result of comments received, the BLM eliminated this requirement in the final rule.
- Lengthening to 2 years the phase-in period for the implementation of GARVS (§ 3175.60(a)(2) and (b)(2)(ii)).

- Lengthening to 2 years the timeframe for getting PMT approval of existing equipment (§ 3175.60(a)(4) and (b)(2)(iii)). Allowing the PMT to approve transducers currently in use with existing data from the manufacturers will greatly reduce the approval timeframe and, in conjunction with the new, 2-year timeframe for PMT approvals, should ease operators' compliance with the new requirements.

Several commenters expressed a concern about being penalized if they cannot meet the deadlines due to delays within BLM, such as the PMT failing to issue approvals in a timely manner. In deciding how to target its enforcement actions, the BLM will take into account any evidence that BLM delays contributed to an operators' noncompliance. No changes to the rule were made based on these comments.

One commenter recommended that the BLM implement a series of training programs for operators during the phase-in periods. The BLM will consider outreach programs; however, no changes to the rule were made as a result of this comment.

Proposed § 3175.60(b)(1)(ii) and (b)(2)(ii) would have included some exceptions to the compliance timelines for high-volume and very-high-volume FMPs. To implement the gas-sampling frequency requirements in proposed § 3175.115, the gas-analysis submittal requirements in proposed § 3175.120(f) would have gone into effect immediately for high-volume and very-high-volume FMPs on the effective date of the final rule. This would have allowed the BLM to immediately start developing a history of heating values and relative densities at FMPs to determine the variability and uncertainty of these values. As discussed above, however, the BLM decided to allow for a 2-year window from the effective date of the rule for the implementation of GARVS, including for FMPs existing before the effective date of the rule (§ 3175.60(b)(1)(iii)).

Although this rule will supersede Order 5 and any NTLs, variance approvals, and written orders relating to gas measurement, paragraph (c) specifies that their requirements will remain in effect through the timeframes specified in paragraph (b). Paragraph (d) establishes the dates on which the applicable NTLs, variance approvals, and written orders relating to gas measurement will be rescinded. These dates correspond to the phase-in timeframes given in paragraph (b). The BLM did not receive any comments on this paragraph.

The BLM received a few comments regarding the proposed requirement in § 3175.60(b)(2) on timeframes to retrofit chart recorders used on low- and very-low volume FMPs. The BLM did not make any changes based on these comments. The rule allows 2 years for low-volume FMPs to come into compliance with the new rule and 3 years for very-low-volume FMPs. The BLM believes that this provides enough time for operators to make the relatively few changes required for mechanical recorders in the rule. Based on other comments, the BLM raised the very-low-/low-volume threshold from 15 Mcf/day to 35 Mcf/day, which significantly decreases the number of mechanical recorders that fall into the low-volume FMP category.

Several commenters stated that the timeline to implement the required changes was unreasonable due to workforce constraints, and the end result would not increase accuracy or royalties. Based on these and other comments, the BLM extended the timeframe for very-high-volume FMPs to comply with these requirements from 6 months to 1 year. The compliance timeframes for high-, low-, and very-low-volume FMPs remain at 1 year, 2 years, and 3 years, respectively. As stated above, the 1-year compliance timeframe only applies to high- and very-high-volume FMPs, which only make up 11 percent of all FMPs nationwide under the new flow-rate category definitions.

The BLM disagrees with the statement that these rules will not increase accuracy. For one thing, the accuracy, or uncertainty, for very-high-volume FMPs must improve from the ±3 percent allowed in the statewide NTLs to ±2 percent under this rule. Similarly, the requirement to eliminate statistically significant bias in the final rule will ensure that the calculation of uncertainty only involves random error, representing a risk of mismeasurement, and not systemic error, which would result in actual mismeasurement. The BLM also notes that many of the changes in this rule are aimed at improving the verifiability of measurement, not the accuracy.

As for whether the rule will increase royalties, the BLM notes that the goal of the rule is to reduce uncertainty (improve accuracy), remove bias, and increase verifiability to ensure that the public and tribes receive their fair share of royalty on the gas removed and sold from their leases. The goal was not necessarily to increase royalty payments, but rather to ensure that all royalties due are paid. Royalty payments may increase as a result of this rule, but the BLM cannot predict whether net payments will increase in every instance as a result of this rule. The BLM did not make any changes to the rule based on these comments.

§ 3175.61 – Grandfathering

This section was added to the final rule based on numerous comments regarding the cost of some of the requirements in the proposed rule, and based on the BLM's Threshold Analysis, which re-examined some of the economic impacts based on information received during the comment period.

In the proposed rule, the BLM did not propose to "grandfather" existing equipment. Operators would have been required to upgrade measurement equipment at FMPs to meet the new standards, except at those FMPs that were specifically exempted in the rule. The BLM received many comments, however, expressing that existing equipment should be grandfathered to avoid changing out or upgrading equipment that is working.

In general, commenters expressed the concern that without grandfathering, they would be forced to plug and abandon wells—particularly low producing wells—due to the high cost of retrofitting existing facilities. Other commenters stated that equipment should be grandfathered if the operator can demonstrate it meets the performance goals under this rule or unless and until the BLM determines the equipment is inaccurate. Several commenters stated that existing equipment should be grandfathered because the BLM implicitly accepts this equipment as being accurate under Order 5. One commenter suggested that the BLM should grandfather existing equipment when the repair cost exceeds 50 percent of a new installation. One commenter stated that retroactive requirements should only apply to high- and very-high-volume FMPs. The BLM also received numerous comments requesting specifically that the BLM grandfather existing meter tubes at FMPs because meter tubes installed before the standards of API 14.3.2 came out in 2000 would not comply with some of the requirements in § 3175.80.

In addition to these general comments, the commenters also expressed concern about four specific requirements in proposed § 3175.80 pertaining to meter tubes:

- The orifice plate perpendicularity and eccentricity at all FMPs would have to meet the standards of API 14.3.2, Subsection 6.2 (Table 1 to § 3175.80). The term "perpendicularity" refers to the orifice plate being perpendicular to the direction of flow. The term "eccentricity" refers to the centering of the orifice plate in the meter tube. These standards require less eccentricity than the previous 1985 version of AGA Report No. 3.

- The meter tube construction and condition at low-, high-, and very-high-volume FMPs would have to meet the standards in § 3175.80(f). These standards refer to the requirements in API 14.3.2, Subsections 5.1 through 5.4 and require higher tolerances for meter tube roundness than the previous 1985 version of AGA Report No. 3 required.
- The design of tube bundles at low-, high-, and very-high-volume FMPs would have to meet the requirements in § 3175.80(g). These requirements refer to the tube-bundle construction requirements in API 14.3.2, Subsections 5.5.2 through 5.5.4. The previous 1985 version of AGA Report No. 3 did not specify the number of tubes that the tube-bundle straightening vane could have, whereas the API 14.3.2 standards incorporated by reference in this rule only allow 19 tubes.
- The meter tube length and tube-bundle placement for low-, high-, and very-high-volume FMPs would have to meet the requirements in § 3175.80(k). These requirements refer to API 14.3.2, Subsection 6.3. The meter tube length requirements in API standards incorporated by reference in the proposed rule were generally the same, or very close to, the meter tube length requirements in the previous 1985 version of AGA Report No. 3, especially at Beta ratios below 0.5. However, there are some specific situations where the lengths under the new API standard are much longer than those required in the 1985 standard. In addition, for Beta ratios of 0.5 or

greater, the tube-bundle placement standards are much different in the new API than in the previous 1985 version.

The commenters cited multiple reasons for exempting existing meter tubes from these requirements. The commenters stated that meter tubes installed before the standards of API 14.3.2 came out in 2000 do not comply with some of the requirements in § 3175.80, and noted the high cost of replacing the large number of meter tubes installed under the 1985 standard (or under previous standards), the likely manufacturing delays that would result when operators simultaneously ordered a high number of replacement meter tubes, and the negligible revenue benefit that would result from replacing meter tubes. One commenter also recommended that the eccentricity requirements only apply to high- and very-high-volume FMPs.

The BLM partially agrees with these comments, and therefore decided to modify the final rule to provide for limited grandfathering of meter tubes and flow-computer software at certain FMPs. Specifically, the BLM changed Table 1 to § 3175.80 so that neither the eccentricity nor the pendicularity requirement applies to very-low-volume FMPs. Further, the BLM added a grandfathering clause (§ 3175.61(a)) that exempts meter tubes at low- and high-volume FMPs installed before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] from the perpendicularity and eccentricity requirements in Table 1 to § 3175.80; the construction and condition requirements in § 3175.80(f); and the meter tube length requirement in § 3175.80(k). However, these meter tubes have to meet the 1985 AGA Report No. 3 standards for eccentricity (see § 3175.61(a)(1)), construction and condition (see § 3175.61(a)(2)), and meter tube length (see § 3175.61(a)(3)). The rule does not grandfather the design and location of flow conditioners, including tube bundles, for reasons outlined in the discussion under § 3175.80(g) regarding tube-bundle design and § 3175.80(k) regarding tube-bundle placement.

In addition, the BLM added a clause for grandfathered meter tubes used at high-volume FMPs, which allows the BLM to add 0.25 percent to the discharge coefficient uncertainty when determining overall measurement uncertainty under § 3175.31(a)(1). The discharge coefficient uncertainty used in the BLM uncertainty calculator is based on data presented in API 14.3.1, which assumes the meter tube meets all the standards under API 14.3.2. The looser tolerances in AGA Report No. 3 (1985) likely result in higher levels of discharge coefficient uncertainty than those resulting from the tighter tolerances in API 14.3.2, although the BLM does not know specifically how much higher. Based on its experience with meter testing, the BLM believes that an increase in discharge coefficient uncertainty of 0.25 percent is reasonable to account for the looser tolerances under AGA Report No. 3 (1895). If operators submit test data to the PMT showing that meter tubes constructed under the 1985 standard result in an increase in the discharge coefficient uncertainty of less than 0.25 percent, or no increase at all, the BLM may approve a lower percentage. The 0.25 percent increase in discharge coefficient uncertainty does not apply to low-volume FMPs because low-volume FMPs are not subject to the uncertainty requirements under § 3175.31(a).

Several commenters asked that the BLM grandfather flow computers that are currently in use without requiring operators to go through the testing protocol. The BLM agrees with this comment, at least for very-low and low-volume FMPs. Accordingly, the BLM changed § 3175.44 so that the testing of flow-computer software is no longer required for very-low and low-volume FMPs (see the discussion under § 3175.44). Because flow-computer software used at existing very-low and low-volume FMPs is grandfathered from having to perform the calculations in the latest API standards, there is no benefit in requiring this software to be tested under § 3175.44. The testing protocol in § 3175.140 compares the calculations from the flow-computer software with the calculations from reference software using the latest API equations. Therefore, there would be no benefit in comparing grandfathered flow computers, using older calculation methodologies to reference software using the latest API methodologies. The results would most likely not match, not due to errant flow computer software, but due to the different methodologies used.

One commenter stated that the BLM should grandfather the calculation methodologies at existing flow computers and allow them to calculate supercompressibility under AGA Report No. 8, (1992), which is already programmed into the commenter's flow computers. The BLM did not make any changes to the rule based on this comment because AGA Report No. 8 (1992) is the most current method of calculating supercompressibility and is incorporated by reference (see § 3175.30). Any flow computer that is programmed with the AGA Report No. 8 software will be in compliance with the rule.

Another commenter suggested that the BLM should grandfather existing flow computers from having to comply with § 3175.103(a)(1) which requires flow rate calculations to be done in accordance with API 14.3.3 (2013) and supercompressibility calculations to be done in accordance with AGA Report No. 8 (1992). The commenter stated that older flow computers may not have the latest calculation software, and it may be difficult or impossible to upgrade the flow computers, especially if they are no longer supported by the manufacturer. In these cases, according to the commenter, operators would choose to prematurely plug and abandon wells rather than incur the cost of a new flow computer. The BLM agrees with these comments as they relate to very-low and some low-volume FMPs, and added § 3175.61(b) to the final rule to address flow computers installed at these FMPs before the effective date of the rule. A summary of the calculation methodologies of the older API and AGA standards and the response to the commenter's suggestion are addressed below.

- API 14.3.3 (1992): The primary difference between the API 14.3.3 (2013) calculation and the API 14.3.3 (1992) calculation involves the gas expansion factor. The 2013 edition of API 14.3.3 uses a different equation for the gas expansion factor which is based on a more thoroughly vetted dataset than the 1992 edition. Use of the equation from the 1992 standard results in a statistically significant bias of greater than 0.25 percent when the ratio of differential pressure to static pressure exceeds the values listed in Table G.1 of API 14.3.3 (2013), Annex G. When the differential pressure to static pressure ratio is below these values, the bias is less than 0.25 percent, which the BLM does not consider to be statistically significant.
- AGA Report No. 3 (1985): This standard, which was the predecessor to the API 14.3.3 standards, not only uses the older version of the gas expansion factor equation, it uses a different and less accurate version of the calculation used to determine the discharge coefficient. In addition, the 1985 calculation uses a non-iterative calculation approach that further contributes to reduced accuracy. Both

the 1992 and 2013 API 14.3.3 calculations use an iterative process and a more accurate equation for the discharge coefficient, resulting in a more accurate calculation of flow rate. The 1992 and 2013 API standards also quantify the uncertainty of the discharge coefficient calculation in greater detail than in AGA Report No. 8 (1985).

- PRCI NX-19: This standard, which was the predecessor of AGA Report No. 8, defines a calculation method for supercompressibility that is less accurate and more limited in its application than the AGA Report No. 8 calculation. The BLM does not know if the PRCI NX-19 calculation results in statistically significant bias compared to the AGA Report No. 8 calculation, however.

Because high- and very-high-volume FMPs must meet uncertainty, bias, and verifiability requirements of § 3175.31(a), (c), and (d), respectively, the BLM believes it is appropriate to require the use of the latest calculation methodologies in API 14.3.3 (2013) and AGA Report No. 8 (1992) at these FMPs, whether they are new or existed as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. Therefore, the BLM did not grandfather the calculation requirements of § 3175.103(a)(1) for high- and very-high-volume FMPs.

Low-volume FMPs do not have to meet the uncertainty requirements of § 3175.31(a), but they must still meet the bias and verifiability requirements of § 3175.31(c) and (d), respectively. Therefore, the BLM believes that allowing the use of the API 14.3.3 (1992) calculations at existing low-volume FMPs, where the differential pressure to static pressure ratio is less than those values in Table G.1, of API 14.3.3 (2013), Annex G, is acceptable. As stated previously, the use of the gas expansion equation in API 14.3.3

(1992) does not result in statistically significant bias when the differential pressure to static pressure ratio is less than those values in Table G.1.

Based on the foregoing, the BLM added § 3175.61(b)(2) which grandfathers existing low-volume FMPs from having to use the calculations in API 14.3.3 (2013) (required under § 3175.13(a)(1)(i)) when the differential pressure to static pressure ratio is less than those values specified in Table G.1 of API 14.3.3 (2013), Annex G. However, these FMPs must still use the calculations in API 14.3.3 (1992). If the differential pressure to static pressure ratio at an FMP, calculated using the monthly average values of differential pressure and static pressure, ever exceeds the values listed in Table G.1 of Annex G, the operator will have to upgrade the flow computer to use the latest calculation methodology in API 14.3.3 (2013). The BLM does not believe this restriction will result in significant cost to operators. The easiest and cheapest remedy for a high differential pressure to static pressure ratio is to install a larger orifice plate which will reduce the differential pressure and reduce the differential pressure to static pressure ratio below the limits in Table G.1.

The BLM did not grandfather the supercompressibility calculations for low-volume FMPs that use the older PRCI NX-19 equation because the BLM does not know whether the use of that equation results in statistically significant bias. In addition, the latest AGA Report No. 8 calculation has been available since 1992 and it is highly unlikely that any new or existing flow computer at a low-volume FMP would still be running the PRCI NX-19 calculations.

Very-low-volume FMPs only need to meet the verifiability requirements under § 3175.31(c). While the older calculation methodologies described above can result in higher uncertainty and statistically significant bias, the calculations are verifiable. Therefore, the BLM added § 3175.61(b)(1), which grandfathers existing very-low-volume FMPs from having to having to meet the calculation standards of § 3175.103(a)(1). However, existing very-low-volume FMPs must still run the calculations methodologies listed previously. As with low-volume FMPs, the BLM did not see any rationale to exempt all very-low-volume FMPs (new and existing) from the calculation requirements of § 3175.103(a)(1) because virtually all flow computers installed at new FMPs will comply with § 3175.103(a)(1).

One commenter suggested that if the BLM agreed to grandfather existing facilities, the operator could add 0.1 percent to the volume measured by the FMP to ensure the Federal Government or Indian tribes did not get shortchanged as a result of any inaccuracies in the existing equipment. The BLM disagrees with this comment. The BLM's goal in promulgating this rule is to ensure that the Federal Government and Indian tribes receive their fair share of royalty on the gas removed from their leases, based on accurate measurement, not to increase royalty payments. There is no reason to think that the royalty measurement problems this rule aims to address—inaccuracy, non-verifiability, and bias—result in a systematic 0.1 percent underestimate of volumes produced;[9] adding 0.1 percent to volume measurements would therefore do little to ensure receipt of fair royalties. On the contrary, this approach would merely add another source of inaccuracy. The BLM did not make any changes to the rule based on this comment.

[9] The BLM notes that this rule eliminates two sources of potential bias: (1) Reporting heating values as "wet;" and (2) Failing to account for the liquids that exist in the gas sample. The bias caused by reporting heating value as "wet" can be as high as 1.74 percent, far greater than the 0.1 percent suggested by the commenter. The BLM has no data to ascertain the potential bias caused by the elimination of liquids in a gas sample, but believes it could be significant.

Some commenters stated that all very-low-volume wells should be automatically grandfathered. While the BLM does not provide a blanket grandfathering for all existing very-low-volume FMPs, the provisions of the final rule provide the same outcome. EGM software at very-low-volume FMPs is specifically grandfathered. In addition, all very-low-volume FMPs, existing and new, are exempt from many of the requirements of the rule, including those relating to uncertainty and bias, fluid conditions, Beta ratio limits, orifice plate inspections for newly drilled or re-fractured wells, flow conditioners, meter tube construction and condition, differential pen position (mechanical recorders), volume corrections, temperature measurement, sample probes and sample tubing, gauge lines and manifolds, EGM commissioning, and extended analysis. In addition, the BLM raised the very-low/low-volume threshold from 15 Mcf/day in the proposed rule to 35 Mcf/day in the final rule, which increased the number of FMPs falling within the very-low-volume category from approximately 21,500 FMPs to 35,700 FMPs. Thus, the BLM believes the final rule adequately addresses the commenters' concern about costs of compliance at very-low-volume wells.

§ 3175.70 – Measurement location

Section 3175.70 requires prior approval for commingling of production with production from other leases, unit PAs, or CAs or non-Federal properties before the point of royalty measurement and for measurement off the lease, unit, or CA (referred to as "off-lease measurement"). The process for obtaining approval is explained in subpart 3173. The BLM did not receive any comments on this section.

§ 3175.80 – Flange-tapped orifice plates (primary devices)

General

Section 3175.80 prescribes standards for the installation, operation, and inspection of flange-tapped orifice plate primary devices. The standards include requirements described in the rule as well as requirements described in API standards that are incorporated by reference. Table 1 to § 3175.80 is included to clarify and provide easy reference to which requirements would apply to different aspects of the primary device and to adopt specific API standards as necessary. The first column of Table 1 to § 3175.80 lists the subject area for which a standard exists. The second column of Table 1 to § 3175.80 contains a reference to the standard that applies to the subject area described in the first column. For subject areas where the BLM adopts an API standard verbatim, the specific API reference is shown. For subject areas where there is no API standard or the API standard requires additional clarification, the reference in Table 1 to § 3175.80 cites the paragraph in the section that addresses the subject area.

The final four columns of Table 1 to § 3175.80 indicate the categories of FMPs to which the standard applies. The FMPs are categorized by the amount of flow they measure on a monthly basis as follows: “VL” is very-low volume, “L” is low volume, “H” is high volume, and “VH” is very-high volume. Definitions for these various classifications are included in the definitions section in § 3175.10. An “x” in a column indicates that the standard listed applies to that category of FMP. A number in a column indicates a numeric value for that category, such as the maximum number of months or years between inspections, and is explained in the body of the standard. The requirements of § 3175.80 vary depending on the average monthly flow rate being measured. In general, the higher the flow rate, the greater the risk of mismeasurement, and the stricter the requirements are.

Section 3175.80 adopts API 14.3.1, Subsection 4.1, which sets out requirements for the fluid and flowing conditions that must exist at the FMP (i.e., single phase, steady state, Newtonian, and Reynolds number greater than 4,000). The term “single-phase” means that the fluid flowing through the meter consists only of gas. Any liquids in the flowing stream will cause measurement error. The requirement for single-phase fluid is the same as the requirement for fluid of a homogenous state in AGA Report No. 3 (1985), paragraph 14.3.5.1. The term “steady-state” means that the flow rate is not changing rapidly with time. Pulsating flow that may exist downstream of a piston compressor is an example of non-steady-state flow because the flow rate is changing rapidly with time. Pulsating or non-steady-state flow will also cause measurement error. The requirement for steady-state flow in the rule is essentially the same as the requirement to suppress pulsation in the AGA Report No. 3 (1985), paragraph 14.3.4.10.3. The term “Newtonian fluid” refers to a fluid whose viscosity does not change with flow rate. The requirement for Newtonian fluids in the rule is not specifically stated in the AGA Report No. 3 (1985); however, all gases are generally considered Newtonian fluids.

The Reynolds number is a measure of how turbulent the flow is. Rather than expressed in units of measurement, the Reynolds number is the ratio of inertial forces (flow rate, relative density, and pipe size) to viscous forces. The higher the flow rate, relative density, or pipe size, the higher the Reynolds number. High viscosity, on the other hand, acts to lower the Reynolds number. At a Reynolds number below 2,000, fluid movement is controlled by viscosity and the fluid molecules tend to flow in straight lines parallel to the direction of flow (generally referred to as laminar flow). At a Reynolds number above 4,000, fluid movement is controlled by inertial forces, with molecules moving chaotically as they collide with other molecules and with the walls of the pipe (generally referred to as turbulent flow). Fluid behavior between a Reynolds number of 2,000 and 4,000 is difficult to predict. For most meters using the principle of differential pressure, including orifice meters, the flow equation is based on an assumption of turbulent flow with a Reynolds number greater than 4,000.

Using a typical gas viscosity of 0.0103 centipoise and 0.7 relative density, a Reynolds number of 4,000 is achieved at a flow rate of 5.8 Mcf/day in a 2-inch diameter pipe, 8.7 Mcf/day in a 3-inch diameter pipe, and 11.6 Mcf/day in a 4-inch diameter pipe. The majority of pipe sizes currently used at FMPs are between 2 and 4 inches in diameter. Because low-, high-, and very-high-volume FMPs all exceed 35 Mcf/day by definition, all FMPs within these categories and with line sizes of 4 inches or less, would operate at Reynolds numbers well above 4,000. Very-low-volume FMPs would be exempt from this requirement. Therefore, the requirement to maintain a Reynolds number greater than 4,000 does not represent a significant change from existing conditions. The requirement for maintaining a Reynolds number greater than 4,000 for low-, high-, and very-high-volume FMPs will help ensure the accuracy of measurement in rare situations where the pipe size is greater than 4 inches or flowing conditions are significantly different from the conditions used in the examples above.

Very-low-volume FMPs could fall below this limit, but are exempt from the Reynolds number requirement. While the BLM recognizes that measurement error could occur at FMPs with Reynolds numbers below 4,000, it would be uneconomic to require a different type of meter to be installed at very-low-volume FMPs. The BLM recognizes that not maintaining the fluid and flowing conditions recommended by API can cause significant measurement error. However, the measurement error at such low flow rates will not significantly affect royalty, and the potential error in royalty is small compared to the potential loss of royalty if production were shut in. The BLM did not receive any comments on the adoption of API 14.3.1, Subsection 4.1, regarding required fluid and flowing conditions.

Section 3175.80 adopts API 14.3.2, Section 4, which establishes requirements for orifice plate construction and condition. Orifice plate standards in API 14.3.2, Section 4 are virtually the same as they are in the AGA Report No. 3 (1985). There are no exemptions to this requirement, since the cost of obtaining compliant orifice plates for most sizes used at FMPs (2-inch, 3-inch, and 4-inch) is minimal and orifice plates not complying with the API standards can cause significant bias in measurement. The BLM did not receive any comments on the adoption of API 14.3.2, Section 4 regarding orifice plate construction and condition.

Proposed § 3175.80 would have adopted API 14.3.2, Subsection 6.2, regarding orifice plate eccentricity for all categories of FMPs. As noted earlier in this preamble, the term "eccentricity" refers to the centering of the orifice plate in the meter tube. Eccentricity can affect the flow profile of the gas through the orifice and larger Beta ratio meters (i.e., meters with larger-diameter orifice bores relative to the diameter of the meter tube) are more sensitive to flow profile than smaller Beta ratio meters. For that reason, larger Beta ratio meters have a smaller eccentricity tolerance. In the proposed rule, the BLM specifically asked for data on the cost of this retrofit and on the number of meters that it may affect. The BLM received one comment objecting to the application of orifice plate eccentricity requirements to low- and very-low-volume FMPs. The commenter suggested that low- and very-low-volume FMPs should be exempt from this requirement because the only way to achieve this for older meter runs built to the 1985 API standards would be to replace the meter tube. The commenter stated that this would provide little benefit and would be cost prohibitive for these lower-volume meters. The BLM agrees with this comment and made several changes to the rule as a result. For very-low-volume FMPs, the BLM changed Table 1 to § 3175.80 to reflect that these FMPs are exempt from the eccentricity and perpendicularity requirements of API 14.3.2, Section 6.2. For low-volume FMPs, the rule grandfathers meter tubes existing at FMPs as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] from meeting the eccentricity requirements of API 14.3.2, Subsection 6.2. However, the meter tube would still have to meet the eccentricity requirements of AGA Report No. 3 (1985) (see discussion of grandfathering under § 3175.61). The grandfathering also includes high-volume FMPs. Although this was not addressed in the comments, the BLM Threshold Analysis determined that it may be uneconomic to require operators to replace existing meter tubes at high-volume FMPs. All meter tubes at very-high-volume FMPs must meet the API 14.3.2, Subsection 6.2 standards for eccentricity.

Table 1 also requires the orifice plate to be installed perpendicularly to the meter tube axis as required in API 14.3.2, Subsection 6.2. Virtually all orifice plate holders, new and existing, maintain perpendicularity between the orifice plate and the meter-tube axis. The BLM did not receive any comments regarding the perpendicularity requirement.

§ 3175.80(a)

Section 3175.80(a) defines the allowable Beta ratio range for flange-tapped orifice meters to be between 0.10 and 0.75, as recommended by API 14.3.2. The previous industry standard for orifice meters (AGA Report No. 3 (1985)) established a Beta ratio range between 0.15 and 0.70. In the early 1990s, additional testing was done on orifice meters, which resulted in an increased Beta ratio range and a more robust characterization of the uncertainty of orifice meters over this range. The testing also showed that a meter with a Beta ratio less than 0.10 could result in higher uncertainty due to the increased sensitivity of upstream edge sharpness. Meters with Beta ratios greater than 0.75 exhibited increased uncertainty due to flow profile sensitivity.

This section also applies the Beta ratio limits to low-volume FMPs. The elimination of statistically significant bias is one of the performance goals that applies to low-volume FMPs, and we know of no data showing that bias is not significant for Beta ratios less than 0.10. Generally, if edge sharpness cannot be maintained, it results in a measurement that is biased to the low side. The low limit for the Beta ratio in API 14.3.2 is based on the inability to maintain edge sharpness in Beta ratios below 0.10. Therefore, if the BLM were to allow Beta ratios lower than 0.10 at low-volume FMPs, there would be the potential for bias.

While the increased sensitivity to flow profile due to Beta ratios greater than 0.75 does not generally result in bias (only an increase in uncertainty), this section also maintains the upper Beta ratio limit in API 14.3.2 for low-volume FMPs. It is very rare for an operator to install a large Beta ratio orifice plate on low-volume meters.

Very-low-volume FMPs are exempt from any Beta ratio restrictions in the rule, as indicated in Table 1 to § 3175.80, because at very-low flow rates, it can be difficult to obtain a measureable amount of differential pressure with a Beta ratio of 0.10 or greater. The increased uncertainty and potential for bias associated with allowing a Beta ratio less than 0.10 on very-low-volume FMPs is offset by the ability to accurately measure a differential pressure and record flow.

The BLM received a few comments that stated that the Beta ratio range should be more restrictive, and recommended a range of 0.20 to 0.60 in order to minimize uncertainty. One commenter stated that Beta ratios over 0.60 can cause the meter to over-register, although the commenter did not supply any data to substantiate this claim. The BLM did not make any changes to the rule based on this comment. The BLM is not aware of any data that suggest that Beta ratios over 0.60 will cause a meter to over-register. The BLM is aware that the uncertainty of a flange-tapped orifice plate increases if the Beta ratio is below 0.2 or is greater than 0.6. The uncertainty of a flange-tapped orifice plate as a function of both Beta ratio and Reynolds number is well understood and well documented. The final rule sets an overall uncertainty performance standard that the BLM enforces using the BLM uncertainty calculator. The performance standard allows an operator to offset the higher uncertainties at low or high Beta ratios by reducing the uncertainty of other components of the metering system such as the differential and static-pressure transducers. This allows operators more flexibility. The BLM does not believe that setting uncertainty standards for individual components of the metering system is workable or desirable. The BLM also notes that the minimum orifice plate size of 0.45 inches, as required in § 3175.80(b), effectively raises the minimum Beta ratio allowed under this rule for high- and very-high-volume FMPs. For 2-inch meter tubes, the effective minimum Beta ratio is 0.22; for 3-inch meter tubes, the effective minimum Beta ratio is 0.15; and for 4-inch meter tubes, the effective minimum Beta ratio is 0.11.[10]

§ 3175.80(b)

Section 3175.80(b) establishes a minimum orifice bore diameter of 0.45 inches for high-volume and very-high-volume FMPs. API 14.3.1, Subsection 12.4.1 states: "Orifice plates with bore diameters less than 0.45 inches … may have coefficient of discharge uncertainties as great as 3.0 percent. This large uncertainty is due to problems with edge sharpness." Because the uncertainty of orifice plates less than 0.45 inches in diameter has not been specifically determined, the BLM cannot mathematically account for it when calculating overall measurement uncertainty under proposed § 3175.31(a). To ensure that high- and very-high-volume FMPs maintain the uncertainty required in § 3175.31(a), the BLM is prohibiting the use of orifice plates with bores less than 0.45 inches in diameter. Because there is no evidence to suggest that the use of orifice plates smaller than 0.45 inches in diameter causes measurement bias in low-volume and very-low-volume FMPs, they are allowed for use in these FMPs.

The BLM received several comments stating that this requirement should not apply to existing meters because it could force the operator to replace meter tubes in order to comply with Beta ratio requirements. The BLM does not understand why this requirement would necessitate replacing existing meter tubes and the commenters did not provide an explanation. One commenter stated that an orifice bore less than 0.45 inches is sometimes necessary in meters operating at the low end of the high-volume FMP

[10] These values were derived by dividing the minimum allowable orifice bore diameter of 0.45 inches by typical internal diameters of 2-inch, 3-inch, and 4-inch meter tubes (2.067 inches, 3.068 inches, and 4.026 inches, respectively).

category to raise the differential pressure to provide better measurement accuracy. The BLM disagrees with this comment. Even using the minimum high-volume FMP flow rate of 100 Mcf/day in the proposed rule, a 0.50-inch orifice plate (orifice plates are typically provided in 0.125-inch increments) would generate a differential pressure of 23 inches of water column,[11] which would be high enough in most cases to achieve an overall measurement uncertainty of ±3 percent as required in § 3175.31(a). Because the BLM raised this threshold to 200 Mcf/day in the final rule, a 0.50-inch orifice plate would generate 92 inches of differential pressure using the same assumptions. In other words, there is no reason that an operator would have to use an orifice plate less than 0.45 inches with a high- or very-high-volume FMP. The BLM did not make any changes to the final rule based on this comment.

§ 3175.80(c)

Section 3175.80(c) requires orifice plate inspections upon installation and then every 2 weeks thereafter for FMPs measuring production from wells first coming into production or from existing wells that have been re-fractured. It is common for new wells and re-fractured wells to produce high amounts of sand, grit, and other particulate matter for some initial period of time. This material can quickly damage an orifice plate, generally causing measurement to be biased low. This requirement increases the orifice plate inspection frequency until it can be demonstrated that the production of particulate matter from a new well first coming into production or a re-fractured well has subsided. The once-every-2-week inspection requirement also applies to existing FMPs already

---

[11] Assumes a relative density of 0.7 and a static pressure of 200 psia.

measuring production from one or more other wells, which measures gas from a new well first coming into production or from a well that has been re-fractured.

Under this rule, once an inspection demonstrates that no detectable wear occurred over the previous 2 weeks, the BLM will consider the well production to have stabilized and the inspection frequency will revert to the frequency in Table 1 to § 3175.80. There are no exemptions for this requirement because: (1) Based on the BLM's experience, pulling and inspecting an orifice plate generally takes less than 30 minutes and is a low-cost operation; and (2) In most cases, the new requirement will not apply to very-low-volume FMPs anyway because rarely would a newly drilled well have only very-low-volume levels of gas production.

The BLM received several comments objecting to the once-every-2-week inspection requirement. One commenter stated that this frequency of inspections is not necessary unless there is evidence of plate degradation, while other commenters suggested the inspection frequency should be monthly instead of every 2 weeks. The BLM disagrees with these comments. The only way an operator would know if there was evidence of plate degradation is to pull and inspect the orifice plate. The BLM believes that orifice plate inspections every 2 weeks are important considering how much a dulled edge on an orifice plate can bias the measured flow rate, usually to the low side. Although the BLM did not make any changes to the inspection requirement, very-low-volume FMPs are no longer subject to this requirement because bias is not one of the performance criteria for the very-low-volume category.

The BLM received one comment stating that assessing whether there has been wear over the previous 2 weeks in order to determine if an orifice plate change is still necessary is subjective and recommended that the BLM provide guidance and training for BLM inspectors. Although the BLM does not agree that assessing an orifice plate is subjective, the BLM does agree that guidance and training are necessary. The BLM will include additional guidance in the enforcement handbook. The comment did not suggest any changes to the rule. The BLM did not make any changes to the rule based on this comment.

Several commenters objected to the proposed requirement that an operator must determine whether the orifice plate meets the eccentricity requirements of API 14.3.2, Subsection 6.2, during an orifice plate inspection under this paragraph. The commenters stated that eccentricity can only be determined during a detailed meter tube inspection. The BLM agrees with this comment and moved the eccentricity requirement from this paragraph to the detailed meter tube inspection paragraph (see § 3175.80(i)).

The BLM added a phrase to the proposed rule, clarifying that the BLM considers a well that has been re-fractured to have the same impact on an orifice plate that a new well has, and therefore to require inspections every 2 weeks for re-fractured wells. Like new wells, re-fractured wells produce tremendous amounts of sand and grit during flow back and this sand and grit have the potential to quickly dull an orifice plate in the same manner as the sand and grit produced from a new well.

§ 3175.80(d)

Section 3175.80(d) establishes a frequency for routine orifice plate inspections. The term “routine” in Table 1 to § 3175.80 is used to differentiate this requirement from § 3175.80(c) of this rule, which is related to new FMPs measuring production from new and re-fractured wells. Under this rule, the inspection frequency depends on the flow rate category the FMP is in. The required inspection frequency, in months, is given in Table 1 to § 3175.80. More than any other component of the metering system, orifice plate condition has one of the highest potentials to introduce measurement bias and create error in royalty calculations. The higher the flow rate being measured, the greater the risk to ongoing measurement accuracy. Therefore, the higher the flow rate, the more often orifice plate inspections are required. For high-volume and very-high-volume FMPs, the frequency of orifice plate inspections is every 3 months and every month, respectively. For very-low-volume FMPs, the frequency is every 12 months; and for low-volume FMPs, the frequency is every 6 months.

The BLM received multiple comments both criticizing and supporting the routine orifice plate inspection frequency required in § 3175.80(d). Those objecting to the requirement stated that the orifice plate inspection frequency should be based on need rather than on a fixed frequency, while others asserted that the proposed frequency was too high. Suggested frequencies include once every 1 or 2 years for all FMPs, annually for very-low-volume FMPs, semi-annually for low- and high-volume FMPs, and quarterly for very-high-volume FMPs. The BLM disagrees with these comments. Orifice plate condition, especially the condition of the upstream edge, is perhaps the most critical part of an orifice plate metering system. Even slight changes to the upstream edge of an orifice plate can cause significant bias in the measured flow rate, usually to the low side. The BLM believes that the frequency given in the proposed rule strikes a reasonable balance between the cost to the operator and the need for measurement accuracy. The BLM did not make any changes to the proposed rule based on these comments.

Two commenters suggested that the proposed schedule would be acceptable if the meter was equipped with a senior fitting (a fitting where the orifice plate can be removed without shutting off the flow of gas through the meter). The BLM accepts that orifice plate inspection is much easier and less costly when a senior fitting is used. If an operator makes a determination that it is in their best economic interest to install a senior fitting, they are free to do so. However, the type of plate holder has no bearing on how quickly a plate can become worn or dirty or how a worn or dirty orifice plate can affect measurement and, ultimately, royalty. The BLM did not make any changes to the rule based on this comment.

One commenter stated that orifice plate and meter tube inspection frequency should be left up to the operators, because the requirements in the proposed rule were too burdensome. Although the BLM did not make any changes to the rule based on this comment, changes to the rule based on other comments resulted in an estimated reduction in orifice plate and meter tube inspections costs to industry from $6.3 million per year in the proposed rule to $5.8 million per year in the final rule. The BLM does not consider either of these requirements to be overly burdensome.

One commenter suggested changing the terminology from "every 3 months" and "every 6 months" to "quarterly" and "semi-annually" to provide operators more flexibility. The BLM believes specifying the number of months between calibrations is clearer than the terminology suggested by the commenter. In addition, operators could imply that adoption of "quarterly" and "semi-annually" means an orifice plate inspection on a high-volume FMP could be performed at the beginning of one quarter and at the end of another quarter (January 1 and June 30, for example), which would essentially double the time between inspections. The BLM did not make any changes to the rule based on this comment.

In response to other comments on § 3175.100, the BLM changed the required verification frequency for high-volume FMPs from once every month to once every 3 months (see Table 1 to § 3175.100). This change means that routine orifice plate inspections no longer correspond to verifications for high-volume FMPs. To address this issue, the BLM removed the requirement that routine orifice plate inspections have to be performed at the same time an FMP is verified under § 3175.92 (mechanical recorders) or § 3175.102 (EGM systems).

§ 3175.80(e)

Section 3175.80(e) requires operators to retain, and provide to the BLM upon request, documentation about the condition of an orifice plate that is removed and inspected. Documentation of the plate inspection can be a useful part of an audit trail and can also be used to detect and track metering problems. Although this is a new requirement, many operators already record this information as part of their meter verifications. Thus, this requirement is not a significant change from prevailing industry practice. The BLM did not receive any comments on this paragraph.

§ 3175.80(f)

Proposed § 3175.80(f) would have required all meter tubes to be constructed in compliance with current API standards. This proposed requirement would not have included meter tube lengths, which are addressed in proposed § 3175.80(k). The BLM has reviewed the API standards referenced and believes that they meet the intent of § 3175.31 of the rule.

Proposed § 3175.80(f)(1) and (2) would have included an exception allowing all low-volume FMPs to continue using the tolerances in the AGA Report No. 3 (1985). While the BLM recognizes this could result in higher uncertainty than meter tubes meeting the tolerances of API 14.3.2, it is not imposing uncertainty requirements for low-volume FMPs. In the final rule, this exception is moved to § 3175.61 and paragraphs (1) and (2) of proposed § 3175.80(f) were eliminated. This means that only *existing* low-volume FMPs are exempt from the meter tube construction standards of API 14.3.2, Subsections 5.1 through 5.4 (although they must still meet the 1985 AGA Report No. 3 construction standards). Under the final rule, low-volume FMPs installed after the effective date of this rule must meet the standards of API 14.3.2, Subsections 5.1 through 5.4. Very-low-volume FMPs are exempt from meter tube standards under this paragraph.

The BLM received numerous comments arguing that existing meter tubes should be grandfathered because the only way to comply with the new standards is to replace the meter tube, and this would be very costly. Some commenters questioned the benefit of replacing existing meter tubes. The commenters also suggested that the BLM should hold the operator to the meter-tube standard in place at the time the meter tube was installed. The BLM agrees with these comments, with respect to low- and high-volume FMPs, and has grandfathered existing meter tubes at those FMPs (see the discussion under § 3175.61). To account for the additional uncertainty that may be present in pre-2000 meter tubes, the BLM will add an uncertainty of ±0.25 percent to the discharge coefficient when determining the overall meter uncertainty, unless the operator provides sufficient data to show that the additional uncertainty in discharge coefficient when the meter tube is constructed to the tolerance of the 1985 standard is less than ±0.25 percent (see § 3175.61(a)). The BLM believes that, in the absence of data to the contrary, the ±0.25 percent uncertainty is a reasonable assumption based on its experience with orifice plate test data.

§ 3175.80(g)

Section 3175.80(g) addresses isolating flow conditioners and tube-bundle flow straighteners. To achieve the orifice plate uncertainty stated in API 14.3.1, the gas flow approaching the orifice plate must be free of swirl and asymmetry. This can be achieved by placing a section of straight pipe between the orifice plate and any upstream flow disturbances such as elbows, tees, and valves. Swirl and asymmetry caused by these disturbances will eventually dissipate if the pipe lengths are long enough. The minimum length of pipe required to achieve the uncertainty stated in API 14.3.1 is discussed in § 3175.80(k).

Isolating flow conditioners and tube-bundle flow straighteners are designed to reduce the length of straight pipe upstream of an orifice meter by accelerating the dissipation of swirl and asymmetric flow caused by upstream disturbances. Both devices are placed inside the meter tube at a specified distance upstream of the orifice plate. An isolating flow conditioner consists of a flat plate with holes drilled through it in a geometric pattern designed to reduce swirl and asymmetry in the gas flow. A tube bundle is a collection of tubes that are welded together to form a bundle.

Section 3175.80(g) allows isolating flow conditioners to be used at FMPs if they have been approved by the BLM pursuant to § 3175.46 of this rule, or 19-tube-bundle flow straighteners constructed in compliance with API 14.3.2, Subsections 5.5.2 through 5.5.4, and located in compliance with API 14.3.2, Subsection 6.3. Use of 19-tube-bundle flow straighteners constructed and installed under these API standards does not require BLM approval. The rule requires a tube-bundle flow straightener, if used, to comply with API 14.3.2, Subsections 5.5.2 through 5.5.4 and 6.3, because data have shown that these installations produce almost no additional uncertainty of the discharge coefficient and the small amount of additional uncertainty is accounted for in the determination of overall uncertainty. This rule prohibits the use of 7-tube-bundle flow straighteners, which are used primarily in 2-inch meters. Additionally, 19-tube-bundle flow straighteners are typically not available in a 2-inch size for these existing meters. A significant number of the meters in use currently are 2-inch meters. Without the ability to use either 7- or 19-tube-bundle flow straighteners, 2-inch meters are required to be retrofitted to either: (1) Use a proprietary type of isolating flow conditioner approved in accordance with § 3175.46; or (2) Not have a flow conditioner, which typically requires much longer lengths of pipe upstream of the orifice plate. The rule's requirements with respect to isolating flow conditioners will increase consistency and eliminate the time and expense it takes to apply for and obtain a variance for each FMP.

As indicated in Table 1 to § 3175.80, very-low-volume FMPs are exempt from the requirement to retrofit because the costs involved are believed to outweigh the benefits based upon experience with these production levels.

A few comments on the proposed rule indicated that replacing 7-tube bundles on 2-inch meter tubes will be costly, and suggested that the BLM grandfather meter tubes that comply with the API standard in place when the meter tube was installed. Although the BLM has grandfathered existing meter tubes for perpendicularity, eccentricity, construction and condition, and meter tube length, the BLM did not grandfather existing flow conditioners, including tube bundles on low-, high-, and very-high-volume FMPs. While the grandfathering of the other meter tube aspects can increase the uncertainty of an orifice plate meter, the BLM is not aware of any evidence that they cause bias in the measurement. The design of tube-bundle flow straighteners can, however, cause bias. Because the elimination of statistically significant bias is one of the performance standards in § 3175.31 for low-, high-, and very-high-volume FMPs, the BLM did not make any changes in the final rule based on these comments. The BLM does not believe that requiring existing meter tubes to comply with the new API standards for the design of tube bundles is cost-prohibitive. If the meter tube has a 7-tube bundle, or a tube bundle that does not comply with API 14.3.2, Subsections 5.5.2 through 5.5.4, the operator can replace the tube bundle with an isolating flow conditioner for a few hundred dollars. If the meter tube has an isolating flow conditioner that has not been approved by the BLM, then the operator can replace that isolating flow conditioner with one that has been approved by the BLM. If the operator uses a 19-tube bundle that is located in accordance with the 1985 AGA standard, the BLM deems that this will also comply with the requirements of API 14.3.2, Subsection 6.3 if the Beta ratio is less than 0.5 (see the discussion under § 3175.80(k)).

§ 3175.80(h)

Proposed § 3175.80(h) would have required an internal visual inspection of all meter tubes at the frequency, in years, shown in Table 1 to § 3175.80. The visual inspection would have had to be conducted using a borescope or similar device (which would obviate the need to remove or disassemble the meter run), unless the operator decided to disassemble the meter run to conduct a detailed inspection, which also would meet the requirements of this proposed paragraph. While an inspection using a borescope or similar device cannot ensure that the meter tube complies with API 14.3.2 requirements, it can identify issues, such as pitting, scaling, and buildup of foreign substances that could warrant a detailed inspection under § 3175.80(i) of the proposed rule.

The BLM received many comments stating that borescopes are expensive and have potential safety hazards due to the explosive environment in which they operate. The BLM agrees that the use of borescopes could require additional safety measures and could cause operators to incur significant costs. As a result of these comments, the BLM eliminated the reference to borescopes and made the standards entirely performance-based. The BLM also changed the name of the requirement to a "basic inspection" instead of a "visual inspection" in the proposed rule. This requirement provides that the operator must conduct a "basic inspection that is able to identify obstructions, pitting, and buildup of foreign substances (e.g., grease and scale)." This change will allow the operator to use other methods to meet the performance goal. For example, there may be ultrasonic devices on the market that operators could use externally to meet the intent of this requirement, without incurring the safety risks associated with borescopes. The BLM believes that this requirement may also inspire new technology to accomplish the goals of this requirement safely and cost effectively.

The BLM received several comments addressing the cost burden of performing basic inspections, although no cost figures were included with the comments. The BLM did not make any changes to the proposed rule based on these comments because the BLM believes that basic inspections can be done at relatively little cost. These costs are included in the BLM Threshold Analysis and in the Economic and Threshold Analysis.

Several commenters suggested that the BLM should require a visual inspection only if an orifice plate inspection indicated problems, and that the BLM should train inspectors to recognize when a visual inspection is needed. While the BLM agrees that orifice plate inspections can give some indication as to meter tube problems (such as liquid and grease buildup), they are not reliable. For example, if debris plugged a flow conditioner or a tube-bundle flow straightener, this could have a significant effect on the accuracy of the meter and would not be detected by merely pulling and inspecting the orifice plate. The BLM did not make any changes to the proposed rule based on these comments.

One commenter stated that shutting in wells to perform visual inspections could cause reservoir damage and lower royalty. While there is always some possibility of reservoir damage when shutting in a well, the BLM does not believe this risk is significant enough to warrant the elimination of this requirement. If that were the case, then wells could never be shut in for orifice plate inspections or other routine maintenance. The commenter did not provide any data or studies to substantiate their claim. If an operator demonstrated that this was an issue for a particular well, they could request a variance from the AO. The BLM did not make any changes based on this comment.

Numerous comments objected to the frequency of visual inspections as proposed in Table 1 to § 3175.80. Suggestions for inspection frequency ranged from every 3 years to every 10 years. The BLM did not make any changes to the rule based on these comments because none of the commenters submitted a rationale for their suggested frequencies. The BLM believes the frequencies presented in the proposed rule represent a balance between economic considerations and ensuring accurate measurement of Federal and Indian gas resources.

The BLM removed paragraph (h)(5) of the proposed rule out of concern that operators could have misinterpreted it to mean that a detailed inspection would have been required to meet the standards of a basic inspection. Any type of inspection that can identify obstructions, pitting, and a build-up of foreign substances qualifies as a basic inspection, which includes a detailed inspection as described in paragraph (i) of this section. However, a detailed inspection is not required to meet the standards under § 3175.80(h).

§ 3175.80(i)

Proposed § 3175.80(i) would have required a detailed inspection of meter tubes on high- and very-high-volume FMPs at the frequency, in years, shown in Table 1 to § 3175.80 (10 years for high-volume FMPs and 5 years for very-high-volume FMPs). Under the proposed rule, the AO could have increased this frequency, and could have required a detailed inspection of low-volume FMPs, if the visual inspection identified any issues regarding compliance with incorporated API standards, or if the meter tube operated in adverse conditions (such as corrosive or erosive gas flow), or had signs of physical damage. The goal of the inspection is to determine whether the meter is in compliance with required standards for meter-tube construction. Meter tube inspections would have been required more frequently for very-high-volume FMPs because there is a higher risk of volume errors and, therefore, royalty errors in higher-volume FMPs. Very-low-volume FMPs would have been exempt from the inspection requirement because they would be exempt from the construction standards of API 14.3.2.

Several commenters indicated that detailed meter tube inspections are expensive and present safety issues. Other commenters suggested that the BLM should only require a detailed inspection if the visual inspection indicated it was warranted. Several commenters objected to a single visual inspection leading to a frequency change in the number of detailed inspections on an FMP. Several commenters suggested that the proposed detailed meter tube inspection frequency was inadequate. The BLM agrees with the comments and made several changes to this paragraph as a result. First, the BLM eliminated routine detailed inspections; under the final rule, the BLM will require a detailed inspection only if the findings from a basic inspection warrant a detailed inspection. Second, if a basic inspection reveals the presence of obstructions or buildup of material at a low-volume FMP, the operator will only have to clean the meter tube. For high-volume FMPs, the operator must ensure the meter tube meets all the relevant standards relating to meter tubes before returning the meter to service. For meter tubes installed after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], the relevant standard is API 14.3.2, Subsections 5.1 through 5.4 and 6.2, incorporated by reference in this rule. For meter tubes installed before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], the relevant standard is AGA Report No. 3, which has been incorporated by reference in this rule. For very-high-volume FMPs, regardless of when they were installed, the operator must ensure the meter tube complies with the applicable provisions of API 14.3.2, incorporated by reference in this rule.

One commenter objected to detailed meter tube inspections under any circumstance, while another commenter recommended that the BLM could adjust the frequency of both basic and detailed meter tube inspections based on the findings of previous inspections. The BLM did not make any changes to the rule based on these comments. The BLM believes detailed inspections are required to ensure accurate measurement. While the

BLM agrees that an operator could justify a change in the frequency in certain instances, this should be handled through the variance process on a case-by-case basis.

§ 3175.80(j)

Section 3175.80(j) requires operators to keep documentation of all detailed meter tube inspections to be made available to the BLM upon request. The BLM will use this documentation to establish that the inspections meet the requirements of the rule, for auditing purposes, and to track the rate of change in meter tube condition to support an operator's request for a change of inspection frequency. Very-low-volume FMPs are exempt from this requirement because no meter tube inspections are required. The BLM did not receive any comments on this requirement in the proposed rule.

§ 3175.80(k)

Proposed § 3175.80(k) would have incorporated the standards of API 14.3.2 for the length of meter tubes upstream and downstream of the orifice plate, and for the location of tube-bundle flow straighteners, if they are used (see previous discussion of swirl and asymmetry in § 3175.80(g)). As indicated in Table 1 to § 3175.80, very-low-volume FMPs are exempt from the meter tube length requirements because the costs involved in retrofitting the meter tubes are believed to outweigh the benefits based on experience with these production levels.

The pipe length requirements in AGA Report No. 3 (1985) (incorporated by reference in Order 5) were based on orifice plate testing done before 1985. In the early 1990s, extensive additional testing was done to refine the uncertainty and performance of orifice plate meters. This testing revealed that the recommended pipe lengths in the AGA Report No. 3 (1985) were generally too short to achieve the stated uncertainty levels, especially when the Beta ratio is 0.5 or greater. In addition, the testing revealed that tube bundles placed in accordance with the 1985 AGA Report No. 3 could bias the measured flow rate by several percent.

When API 14.3.2 was published in 2000 (and later updated in 2016), it used the additional test data to revise the meter tube length and tube-bundle location requirements to achieve the stated levels of uncertainty and remove bias. All meter tubes installed after the publication of API 14.3.2 in 2000 should already comply with the more stringent requirements for meter tube length and tube-bundle placement.

Because the meter tube lengths in API 14.3.2 are required to achieve the stated uncertainty, § 3175.80(k)(1) would have adopted these lengths as a minimum standard for high-volume and very-high-volume FMPs. Due to the high-production decline rates in many Federal and Indian wells, the BLM does not expect a significant number of meters that were installed before 2000, under the AGA Report No. 3 (1985) standards, to still be measuring gas flow rates that would place them in the high-volume or very-high-volume categories. However, the BLM Threshold Analysis shows that it would be uneconomic for operators of high-volume FMPs to retrofit the meter tubes to comply with the length requirements in API 14.3.2. Therefore, the final rule grandfathers the meter tube length requirements for the anticipated handful of high-volume FMPs existing before the effective date of the rule (see § 3175.61(a)) that continue to measure high-volume flow rates of gas even after 16 years of production (from 2000 to 2016). These grandfathered FMPs would still have to meet the meter tube length requirements of AGA Report No. 3 (1985). If the meter tube contains a 19-tube bundle flow straightener or isolating flow conditioner, the location of that straightener or flow conditioner will not be grandfathered and will still have to comply with § 3175.80(g). The meter tubes at very-high-volume FMPs were not grandfathered in the final rule.

While low-volume FMPs would not be subject to the uncertainty requirements under § 3175.31(a), they still would have to be free of statistically significant bias under § 3175.31(c). Because testing has shown that placement of tube-bundle flow straighteners in conformance with the AGA Report No. 3 (1985) can cause bias, low-volume FMPs utilizing tube-bundle flow straighteners also would have been subject to the meter tube length requirements of API 14.3.2 under proposed § 3175.80(k)(1).

While this may require some retrofitting of existing meters, the BLM does not expect this to be a significant change for three reasons. First, FMPs installed after 2000 should already comply with the meter tube length and tube-bundle placement requirements of API 14.3.2. Second, based on the BLM's experience, we estimate that fewer than 25 percent of existing meters use tube-bundle flow straighteners. Third, for those FMPs that would need to be retrofitted, most operators would opt to remove the tube-bundle-flow straightener and replace it with an isolating flow conditioner. Several manufacturers make a type of isolating flow conditioner designed to replace tube bundles without retrofitting the upstream piping. These flow conditioners are relatively inexpensive and would not create an economic burden on the operator for low-volume FMPs. The BLM received many comments requesting that the BLM grandfather existing meter tubes from the meter tube length requirements of this paragraph due to the high cost and questionable benefit of this requirement. The commenters also suggested that the BLM should hold the operator to the meter tube standard in place at the time the meter tube was installed. The BLM agrees with these comments and has grandfathered existing meter tubes at low- and high-volume FMPs (see discussion under § 3175.61). To account for the additional uncertainty that may be present on pre-2000 meter tubes, the BLM will add an uncertainty of ±0.25 percent to the discharge coefficient when determining the overall meter uncertainty, unless the operator provides sufficient data to show that the additional uncertainty in discharge coefficient when the meter tube is constructed to the tolerances of the 1985 standard is less than ±0.25 percent. The BLM believes that, in the absence of data to the contrary, the ±0.25 percent uncertainty is a reasonable assumption based on its experience with orifice plate test data.

Proposed § 3175.80(k)(2) would have allowed low-volume FMPs that do not have tube-bundle flow straighteners to comply with the less-stringent meter tube length requirements of the AGA Report No. 3 (1985). For those meter tubes that do not include tube-bundle flow straighteners, the BLM is not currently aware of any data that show the shorter meter tube lengths required in the AGA Report No. 3 (1985) result in statistically significant bias.

The BLM received numerous comments requesting that the BLM grandfather existing meter tubes from the tube bundle location requirements of this paragraph, based on API 14.3.2. Test data have shown that statistically significant measurement bias can occur if the 19-tube-bundle straightening vane is placed at the location required by the 1985 API standard. Because low-, high-, and very-high-volume FMPs are subject to the performance standard in § 3175.31(c), which prohibits statistically significant bias, the BLM did not grandfather flow conditioners, including the required location of 19-tube bundle flow straighteners. However, the BLM has determined that the tube-bundle placement requirements in the 1985 API standards are generally consistent with the tube-bundle placement requirements in the 2000 API standards for Beta ratios less than 0.5. Therefore, the BLM has revised this paragraph to make it clear that the BLM considers tube bundles installed under the 1985 standard to be in compliance with the 2000 standard when the Beta ratio is less than 0.5. In addition, the BLM moved the meter tube length requirements for existing FMPs from this paragraph to the grandfathering section (see § 3175.61(a)).

§ 3175.80(l)

Section 3175.80(l) sets standards for thermometer wells, including the adoption of API 14.3.2, Subsection 6.5, in § 3175.80(l)(1). While the provisions of the API standard proposed for adoption in the proposed rule were the same as those in the AGA Report No. 3, several additional items would have been required. First, proposed § 3175.80(l)(2) would have required operators to install the thermometer well in the same ambient conditions as the primary device. The purpose of measuring temperature is to determine the density of the gas at the primary device, which is used in the calculation of flow rate and volume. A 10- degree error in the measured temperature will cause a 1 percent error in the measured flow rate and volume. Even if the thermometer well is located away from the primary device within the distances allowed by API 14.3.2, Subsection 6.5, significant temperature measurement error could occur if the ambient conditions at the thermometer well are different from the ambient conditions at the orifice plate. For example, if the orifice plate is located inside of a heated meter house and the thermometer well is located outside of the heated meter house, the measured temperature will be influenced by the ambient temperature, thereby biasing the calculated flow rate. In these situations, the proposed rule would have required the thermometer well to be relocated inside of the heated meter house even if the existing location is in compliance with API 14.3.2, Subsection 6.5.

The BLM received several comments on this section. Two of the commenters stated that the difference between the actual and measured gas temperatures at low-, high-, and very-high-volume FMPs is not significant because the flow rate is high enough to distribute the temperature within the pipe. Another commenter stated that the thermal effects are only significant if the thermometer is inserted less than 6 inches into the pipe. Neither of the commenters submitted any data to substantiate their claim, and the BLM was unable to obtain any studies on this subject. The vast majority of FMPs on Federal and Indian leases are 4 inches in diameter or less; therefore the comment regarding thermometer insertion depths of 6 inches is generally irrelevant. Because the BLM could not substantiate the claims by commenters, the BLM did not make any changes to the rule based on these comments.

The BLM also received a few comments recommending that operators could meet the intent of the requirement by insulating the meter tube, which would eliminate the need to move a thermometer well into a heated meter house, for example. The BLM agrees with these comments and added the option of insulating the meter run and adding heat tracing to the meter run. This change is also consistent with API 14.3.2, Subsection 6.6, which recommends insulating the meter tube in the case of temperature differences between the ambient temperature and the temperature of the flowing fluid. It is difficult to define with any uniformity what level of insulation is needed to meet the intent of this requirement due to regional and local variations in operating conditions. Therefore, the BLM did not establish specific requirements with respect to insulation in the final rule and, instead, opted for language that states that the AO may prescribe the quality of the insulation based on site specific factors such as ambient temperature, flowing temperature of the gas, composition of the gas, and location of the thermometer well in relation to the orifice plate (i.e., inside or outside of a meter house).

Section 3175.80(l)(3) applies when multiple thermometer wells exist at one meter. Many meter installations include a primary thermometer well for continuous measurement of gas temperature and a test thermometer well, where a certified test thermometer is inserted to verify the accuracy of the primary thermometer. API does not specify which thermometer well should be used as the primary thermometer. To minimize measurement bias, the gas temperature should be taken as close to the orifice plate as possible. When more than one thermometer well exists, the thermometer well closest to the primary device will generally result in less measurement bias, and therefore, the rule specifies that this thermometer well is the one that must be used for the flowing temperature measurement. The BLM did not receive any comments on this paragraph.

Section 3175.80(l)(4) requires the use of a thermally conductive fluid in a thermometer well. To ensure that the temperature sensed by the thermometer is representative of the gas temperature at the orifice plate, it is important that the thermometer is thermally connected to the gas. Because air is a poor heat conductor, the rule includes a new requirement that a thermally conductive liquid be used in the thermometer well because this would provide a more accurate temperature measurement. The BLM did not receive any comments on this paragraph.

§ 3175.80(m)

Section 3175.80(m) requires operators to locate the sample probe as required in § 3175.112(b). The reference to § 3175.112(b) is in § 3175.80(m) because the sample probe is part of the primary device. Please see the discussion of § 3175.112(b) for an explanation of the requirement. The BLM did not receive any comments on this paragraph.

§ 3175.80(n)

Proposed § 3175.80(n) would have included a requirement for operators to notify the BLM at least 72 hours in advance of a visual or detailed meter-tube inspection or installation of a new meter tube. Because meter tubes are inspected infrequently, it is important that the BLM be given an opportunity to witness the inspection of existing meter tubes or the installation of new meter tubes. Because meter tube inspections would not have been required for very-low-volume FMPs under the proposed rule, they would have been exempt from this requirement.

Several commenters questioned the practicality of performing a detailed inspection on a new pre-fabricated meter tube. The commenters wondered if they would have to disassemble the meter tube in order for the BLM to witness the inspection. Other commenters stated that the 72-hour notice requirement to inspect new meter tubes is impractical for pre-fabricated meter tubes, presumably because the meter tube could be delivered to the FMP on very short notice.

The BLM agrees with these comments and made numerous changes to this section as a result of these comments and to further clarify the notification requirement. First, the BLM moved the notification requirements of proposed § 3175.80(n) into § 3175.80(h) and (i). The notification requirement in § 3175.80(h)(3) requires the operator to notify the

BLM within 72 hours of performing a basic inspection or submit a monthly or quarterly schedule of basic meter tube inspections to the AO. The notification requirement in § 3175.80(i)(3) requires the operator to notify the BLM at least 24 hours before performing a detailed inspection. The requirement for notification of a detailed inspection is different from that of a basic inspection because detailed inspections are no longer routine and cannot be scheduled. Second, the BLM reduced the notification requirement from 72 hours to 24 hours for detailed inspections because some operators may perform a detailed inspection immediately after discovering problems during a basic inspection. Third, to address the comments directly, the BLM added language (see § 3175.80(i)(2)) that allows operators to submit documentation showing that the meter tube complies with the construction requirements of this rule in lieu of disassembling and inspecting the meter tube. This language specifically applies to pre-fabricated meter tubes where the pre-fabrication shop supplies the operator with a specification sheet showing that all dimensions meet the tolerances required by this rule.

One commenter questioned what would happen if the BLM cannot witness a meter tube inspection. The operator’s only obligation is to notify the BLM of the inspection within the required timeframes. If the BLM does not attend, the operator may proceed with the inspection. The BLM did not make any changes to the rule based on this comment.

§ 3175.90 – Mechanical recorder (secondary device)

Section 3175.90(a) limits the use of mechanical recorders, also known as chart recorders, to very-low- and low-volume FMPs. Mechanical recorders will not be allowed at high- and very-high-volume FMPs because they may not be able to meet the uncertainty requirements of § 3175.31(a). Mechanical recorders are subject to many of the same uncertainty sources as EGM systems, such as ambient temperature effects, vibration effects, static pressure effects, and drift. In addition, mechanical recorders are vulnerable to other sources of uncertainty, such as paper expansion and contraction effects and integration uncertainty. Unlike EGM systems, however, none of these effects have been quantified for mechanical recorders. All of these factors contribute to increased uncertainty and the potential for inaccurate measurement.

Because there are no data indicating that the use of mechanical recorders results in statistically significant bias, mechanical recorders are allowed at very-low- and low-volume FMPs due to the limited production from these facilities.

Table 1 to § 3175.90 was developed to clarify and provide easy reference to the requirements that apply to different aspects of mechanical recorders. No industry standards are cited in Table 1 to § 3175.90 because there are no industry standards applicable to mechanical recorders. The first column of Table 1 to § 3175.90 lists the subject of the standard. The second column of Table 1 to § 3175.90 identifies the section and specific paragraph in the rule that apply to each subject area. (The standards are prescribed in §§ 3175.91 through 3175.94.)

The final two columns of Table 1 to § 3175.90 indicate the FMPs to which the standard applies. The FMPs are categorized by the amount of flow they measure on a monthly basis as follows: "VL" is a very-low-volume FMP and "L" is a low-volume FMP. As noted previously, mechanical recorders are not allowed at high- and very-high-volume FMPs; therefore, Table 1 to § 3175.90 does not include corresponding columns for them. Definitions for the various FMP categories are given in § 3175.10. An "x" in a column indicates that the standard listed applies to that category of FMP. A number in a column indicates a numeric value for that category, such as the maximum number of months or years between inspections, which is explained in the body of the requirement.

The BLM received a comment stating that mechanical recorders should be prohibited because they cannot meet the uncertainty requirements required in § 3175.31 (§ 3175.30 in the proposed rule). The BLM did not make any changes to the rule as a result of this comment because the uncertainty requirements in § 3175.31 do not apply to very-low- and low-volume FMPs, and mechanical recorders are not allowed on any other FMPs.

One commenter stated that if the BLM was going to continue to allow mechanical recorders, the recorders at very-low-volume FMPs should meet the same requirements as mechanical recorders at low-volume FMPs. The BLM disagrees. The exemptions for very-low-volume FMPs were provided to reduce the risk that an operator might choose to shut in production instead of upgrading the meter. The BLM did not make any changes to the rule based on this comment.

§ 3175.91 – Installation and operation of mechanical recorders

§ 3175.91(a)

Section 3175.91(a) sets requirements for gauge lines. Gauge lines connect the pressure taps on the primary device to the mechanical recorder and can contribute to bias and uncertainty if not properly designed and installed. For example, a leaking or improperly sloped gauge line could cause significant bias in the differential pressure and static pressure readings. Improperly installed gauge lines can also result in a phenomenon known as “gauge line error,” which tends to bias measured flow rate and volume. This is discussed in more detail below.

The proposed requirement in § 3175.91(a)(1) would have required a minimum gauge line internal diameter of 3/8 inches to reduce frictional effects that could result from smaller diameter gauge lines. These frictional effects could dampen pressure changes received by the recorder, which could result in measurement error.

The BLM received numerous comments regarding the proposed requirement of 3/8-inch minimum inside diameter gauge lines. The commenters stated that most gauge lines in place have a 3/8-inch nominal diameter with an internal diameter that is less than 3/8 inch. The commenters objected to the 3/8-inch internal diameter because it would require them to replace the existing gauge lines at a high cost with negligible benefit to measurement accuracy. The commenters recommended allowing 3/8-inch nominal diameter gauge lines. The BLM agrees with this comment as the original intent was a 3/8-inch nominal diameter. As a result, the BLM changed the requirement from a 3/8-inch internal diameter to a 3/8-inch nominal diameter.

Proposed § 3175.91(a)(2) would have allowed only stainless-steel gauge lines. Carbon steel, copper, plastic tubing, or other material could corrode and leak, thus presenting a safety issue as well as resulting in biased measurement.

The BLM received a few comments objecting to the requirement of stainless steel gauge lines because many operators have carbon steel gauge lines that would have to be replaced, resulting in excessive cost and a negligible benefit to measurement accuracy. The commenters stated that carbon steel gauge lines should be acceptable in most situations and that stainless steel should only be required in corrosive environments. The BLM's primary concern in proposing stainless steel gauge lines is that the use of plastic lines could lead to loops or sags that could trap liquids. The BLM agrees with these comments and removed the requirement for gauge lines to be constructed of stainless steel. The BLM added language to § 3175.91(a)(2) (§ 3175.91(a)(3) in the proposed rule) that prohibits visible sag in the gauge line.

Section 3175.91(a)(2) requires gauge lines to be sloped up and away from the meter tube to allow any condensed liquids to drain back into the meter tube. A build-up of liquids in the gauge lines could significantly bias the differential pressure reading. The BLM did not receive any comments on this section, although it added the phrase regarding sags as discussed above.

Requirements in § 3175.91(a)(3) through (6) are intended to reduce a phenomenon known as "gauge line error," which is caused when changes in differential or static pressure due to pulsating flow are amplified by the gauge lines, thereby causing increased bias and uncertainty. API 14.3.2, Subsection 5.4.3, recommends that gauge lines be the same diameter along their entire length, which the BLM adopted as a standard in § 3175.91(a)(3).

Section 3175.91(a)(4) and (5) are intended to minimize the volume of gas contained in the gauge lines because excessive volume can contribute significantly to gauge-line error whenever pulsation exists. These paragraphs allow only the static-pressure connection in a gauge line and prohibit the practice of connecting multiple secondary devices to a single set of pressure taps, the use of drip pots, and the use of gauge lines as a source for pressure-regulated control valves, heaters, and other equipment. Section 3175.91(a)(6) limits the gauge lines to 6 feet in length, again to minimize the gas contained in the gauge lines.

As indicated in Table 1 to § 3175.90, very-low-volume FMPs are exempt from the requirements of § 3175.91(a) because any bias or uncertainty caused by improperly designed gauge lines of very-low-volume FMPs would not have a significant royalty impact.

The BLM received a few comments objecting to these requirements because they would eliminate the use of drip pots, which, according to the commenters, are required in some areas to prevent freezing. The BLM did not make any changes to the rule based on these comments because, if freezing is an issue, then it must be resolved by properly sloping gauge lines to avoid the accumulation of liquids, rather than by using drip pots.

§ 3175.91(b)

Section 3175.91(b) requires that the differential pressure pen record at a minimum reading of 10 percent of the differential-pressure bellows range for the majority of the flowing period. The integration of the differential pen when it is operating very close to the chart hub can cause substantial bias because a small amount of differential pressure could be interpreted as zero, thereby biasing the volume represented by the chart. A reading of at least 10 percent of the chart range will provide adequate separation of the differential pen from the "zero" line, while still allowing flexibility for plunger lift operations that operate over a large range. Very-low-volume FMPs are exempt from this requirement due to the cost associated with compliance.

The BLM received a few comments stating that this should not apply to inverted charts since the chart inversion yields better resolution for integration. With an inverted chart, the differential pen is moved to record on the opposite side of the chart as it normally would be. In this configuration, when the differential pressure pen is reading zero, it rests on the outer line of the chart and as the differential pressure increases, it moves closer to the hub. By moving the zero line from the hub of the chart to the outer edge of the chart, the integrator is better able to distinguish the “zero” line from the differential pen trace. The BLM agrees with this comment and added an exception for inverted charts to § 3175.91(b).

§ 3175.91(c)

Section 3175.91(c) requires the flowing temperature to be continuously recorded and used in the volume calculations under § 3175.94(a)(1) for low-volume FMPs (as provided in Table 1 to § 3175.90). Flowing temperature is needed to determine flowing gas density, which is critical to determining flow rate and volume. Typically, an indicating thermometer is inserted into the thermometer well during a chart change. That instantaneous value of flowing temperature is used to calculate volume for the chart period. This introduces a significant potential bias into the calculations. If, for example, the temperature is always obtained early in the morning, then the flowing temperature used in the calculations will be biased low from the true average value due to lower morning ambient temperatures. A continuous temperature recorder is used to obtain the true average flowing temperature over the chart period with no significant bias. Because § 3175.31(c) prohibits statistically significant bias for low-volume FMPs, the rule requires continuous recorders for low-volume FMPs, but not for very-low-volume FMPs, as specified in Table 1 to § 3175.90.

The BLM received a few comments objecting to the cost to retrofit the recording device with a third pen to continuously record temperature. The commenters stated that temperature could be based on a fixed temperature or with a separate temperature recorder. The final rule does not require the temperature to be recorded on the same chart as the differential and static pressure; therefore, recording temperature on a separate temperature recorder would satisfy this requirement. A fixed temperature would be allowed for very-low-volume FMPs, but is not allowed for low-volume FMPs because of the potential for bias. The BLM did not make any changes to the rule based on these comments. The BLM included the cost of adding a temperature recorder (assumed to cost $500) in determining the upper limit of the very-low-volume FMP category (see the BLM Threshold Analysis for subpart 3175 Flow Category Tiers).

§ 3175.91(d)

Section 3175.91(d) requires certain information to be available onsite at the FMP and available to the AO at all times. This requirement allows the BLM to calculate the average flow rate indicated by the chart and to verify compliance with this rule. The information that is required under § 3175.91(d)(2), (3), (7), and (8) typically is already available onsite. For example, the static pressure and temperature element ranges are stamped into the elements and are visible to BLM inspectors, and the meter-tube inside diameter is typically stamped into the downstream flange or is on a tag as part of the device holder, making it visible and available to the BLM.

The information that the operator must retain onsite at the FMP under § 3175.91(d)(1), (4), (5), (6), (9), (10), (11), (12), and (13) was not previously required and thus typically has not been maintained onsite as a matter of practice. The information required in these paragraphs include: The differential-pressure-bellows range; the static-pressure-element range; the temperature-element range; the relative density (specific gravity) of the gas; the units of measure for static pressure (pounds per square inch absolute (psia) or pounds per square inch gage (psig)); the meter elevation; the orifice bore or other primary-device dimensions necessary for device verification, Beta- or area-ratio determination and gas volume calculation; make, model, and location of approved isolating flow conditioner (if used); the location of the downstream end of 19-tube-bundle flow straighteners (if used); the date of the last primary-device inspection; and the date of the last meter verification.

The BLM received a few comments stating that the information was generally on the back of the flow chart and would satisfy the requirement of § 3175.91(d). The BLM did not make any changes to the rule based on these comments. The BLM inspectors are instructed not to manipulate measurement equipment, which includes removing flow charts from the recorder to access the information on the back of the chart, because of concerns for safety and liability.

§ 3175.91(e)

Section 3175.91(e) requires the differential-pressure, static-pressure, and temperature elements to be operated within the range of the respective elements. Operating any of the elements beyond the upper range of the element will cause the pen to record off the chart. When a chart is integrated to determine volume, any parameters recorded off the chart will not be accounted for, which results in biased measurement. Operating a mechanical recorder within the range of the elements is common industry practice. The BLM did not receive any comments on this paragraph.

§ 3175.92 – Verification and calibration of mechanical recorders

§ 3175.92(a)

Section 3175.92(a) sets requirements for the verification and calibration of mechanical recorders upon installation or after repairs, and defines the procedures that operators must follow. The rule differentiates the procedures that are specific to this type of verification from a routine verification that is required under § 3175.92(b). The BLM did not receive any comments on any of the requirements under § 3175.92(a) or paragraphs (a)(1) through (7) of this section.

Section 3175.92(a)(1) requires the operator to perform a successful leak test before starting the mechanical recorder verification. The rule specifies the tests that operators must perform. The BLM is requiring this level of specificity because it is possible to perform leak tests without ensuring that all valves, connections, and fittings are not leaking. Leak testing is necessary because a verification or calibration done while valves are leaking could result in significant meter bias. A successful leak test is required to precede a verification.

Section 3175.92(a)(2) requires that the differential- and static-pressure pens operate independently of each other, which is accomplished by adjusting the time lag between the pens. Examples of appropriate time lag are given for a 24-hour chart and an 8-day chart because these are the charts that are normally used as test charts for verification and calibration.

Section 3175.92(a)(3) requires a test of the differential pen arc.

Section 3175.92(a)(4) requires an "as left" verification to be done at zero percent, 50 percent, 100 percent, 80 percent, 20 percent, and zero percent of the differential- and static-pressure- element ranges. Using this set of verification points helps ensure that the pens have been properly calibrated to read accurately throughout the element ranges. This section also clarifies the verification of static pressure when the static pressure pen has been offset to include atmospheric pressure. In this case, the element range is assumed to be in psia instead of psig. For example, if the static-pressure-element-range is 100 psig and the atmospheric pressure at the meter is 14 psia, then the calibrator would apply 86 psig to test the "100 percent" reading as required in § 3175.92(a)(4)(iii). This prevents the pen from being pushed off the chart during verification. As-found readings are not required in this section because as-found readings are not available for a newly installed or repaired recorder

Section 3175.92(a)(5) requires a verification of the temperature element to be done at approximately 10°F below the lowest expected flowing temperature, approximately 10°F above the highest expected flowing temperature, and at the expected average flowing temperature. This requirement ensures that the temperature element is recording accurately over the range of expected flowing temperature.

Section 3175.92(a)(6) establishes a threshold for the amount of error between the pen reading on the chart and the reading from the test equipment that is allowed in the differential-pressure element, static-pressure element, and temperature element being installed or repaired. If any of the required test points are not within the values shown in Table 1 to § 3175.92, the element must be replaced. The threshold for the differential pressure element is 0.5 percent of the element range and 1.0 percent of the range for the static pressure element. These thresholds are based on the published accuracy specifications for a common brand of mechanical recorders used on Federal and Indian land ("Installation and Operation Manual, Models 202E and 208E," ITT Barton Instruments, 1986, Table 1-1). The threshold for the temperature element assumes a typical temperature element range of 0–150ºF with an assumed accuracy of ±1.0 percent of range. This yields a tolerance of 1.5°F, which was rounded up to 2°F for the sake of simplicity. Our experience over the last three decades indicates that a zero error is unattainable.

Section 3175.92(a)(7) establishes standards for when the static-pressure pen is offset to account for atmospheric pressure. The equation used to determine atmospheric pressure is discussed in Appendix A to this rule. This rule adds the requirement to offset the pen before obtaining the as-left values to ensure that the pen offset did not affect the calibration of any of the required test points.

§ 3175.92(b)

Section 3175.92(b) establishes requirements for how often a routine verification must be performed, with the minimum frequency, in months, shown in Table 1 to § 3175.90. The rule requires verification every 3 months for a low-volume FMP and every 6 months for a very-low-volume FMP. The required routine verification frequency for a chart recorder is twice as frequent as it is for an EGM system at low- and very-low-volume FMPs because chart recorders tend to drift more than the transducers of an EGM system.

The BLM received one comment regarding the proposed 6-month routine verification frequency for very-low-volume FMPs. The commenter stated that if chart recorders are permitted, routine verification should occur every 3 months, although no rationale was given by the commenter. The BLM did not make any changes to the rule based on this comment. The BLM believes that a 6-month routine verification frequency is adequate for very-low-volume FMPs because the volumes measured by very-low-volume FMPs are low enough that errors in the mechanical recorder will not have a significant effect on royalty.

§ 3175.92(c)

Section 3175.92(c) establishes procedures for performing a routine verification. These procedures vary from the procedures used for verification after installation or repair, which are discussed in § 3175.92(a). The BLM did not receive any comments on any of the requirements under § 3175.92 (c).

Section 3175.92(c)(1) requires that a successful leak test be performed before starting the verification. See the previous discussion of leak testing under § 3175.92(a)(1). Section 3175.92(c)(2) prohibits any adjustments to the recorder until the as-found verifications are obtained. It is general industry practice to obtain the as-found readings before making adjustments. However, some adjustments are specifically prohibited under this rule. For example, some meter calibrators will zero the static pressure pen to remove the atmospheric-pressure offset before obtaining any as-found values. Once the pen has been zeroed it is no longer possible to determine how far off the pen was reading prior to the adjustment, thus making it impossible to determine whether a volume correction would be required under § 3175.92(f). This section makes it clear that no adjustments, including the previous example, are allowed before obtaining the as-found values.

Section 3175.92(c)(3) requires an as-found verification to be done at zero percent, 50 percent, 100 percent, 80 percent, 20 percent, and zero percent of the differential and static element ranges. The verification points were included to identify pen error over the chart range. Mechanical recorders are generally more susceptible to varying degrees of recording error (sometimes referred to as an “S” curve) than EGM systems.

Section 3175.92(c)(3)(i) requires that an as-found verification be done at a point that represents where the differential and static pens normally operate. This section requires verification at the points where the pens normally operate only if there is enough information onsite to determine where these points are.

Section 3175.92(c)(3)(ii) establishes additional requirements if there is not sufficient information onsite to determine the normal operating points for the differential pressure and static pressure pens. The most likely example would be when the chart on the meter at the time of verification has just been installed and there were no historical pen traces from which to determine the normal operating values. In these cases, additional measurement points are required at 5 and 10 percent of the element range to ensure that the flow-rate error can be accurately calculated once the normal operating points are known. The amount of flow-rate error is more sensitive to pen error at the lower end of the element range than at the upper end of the range. Therefore, more verification points are required at the lower end to allow the calculation of flow-rate error throughout the range of the differential and static pressure elements.

Section 3175.92(c)(4) establishes standards for determining the as-found value of the temperature pen. In a flowing well, the use of a test thermometer well is preferred because it more closely represents the flowing temperature of the gas compared to a water bath, which is often set at an arbitrary temperature. However, if the meter is not flowing, temperature differences within the pipeline may occur, which have the potential to introduce error between the primary-thermometer well and the test-thermometer well, thereby causing measurement bias. If the meter is not flowing, temperature verification must be done using a water bath.

Section 3175.92(c)(5) establishes a threshold for the degree of allowable error between the pen reading on the chart and the reading from the test equipment for the differential, static, or temperature element being verified. If any of the required points to be tested, as defined in § 3175.92(c)(3) or (4), are not within these thresholds, the element must be calibrated. For a discussion of the thresholds, see the previous discussion in § 3175.92(a)(6) and (7).

Section 3175.92(c)(6) requires that the differential- and static-pressure pens operate independently of each other, which is accomplished by adjusting the time lag between the pens. Please see previous discussion in § 3175.92(a)(3) for further explanation of this requirement.

Section 3175.92(c)(7) requires a test of the differential-pen arc.

Section 3175.92(c)(8) requires an as-left verification if an adjustment to any of the meter elements was made. Obtaining as-left readings whenever a calibration is performed is standard industry practice. The purpose of the as-left verification is to ensure that the calibration process, required in § 3175.92(c)(5) through (7), was successful before returning the meter to service.

Section 3175.92(c)(9) establishes a threshold for the amount of error allowed in the differential, static, or temperature element after calibration. If any of the required test points, as defined in § 3175.92(c)(3) and (4), are not within the thresholds shown in Table 1 to § 3175.92, the element must be replaced and verified under § 3175.92(c)(5) through (7).

Section 3175.92(c)(10) establishes standards if the static-pressure pen is offset to account for atmospheric pressure. Please see previous discussion in § 3175.92(a)(7) for further explanation of this requirement. Very-low-volume FMPs are not exempt from any of the verification or calibration requirements in § 3175.92(c) because these requirements do not result in significant additional cost and are necessary for the BLM to verify the measurement. The BLM did not receive any comments on this provision, and therefore did not make any changes to the rule.

§ 3175.92(d)

Section 3175.92(d) specifies the documentation that must be generated and retained by operators in connection with each verification. This information includes: The time and date of the verification and the prior verification date; primary-device data (meter-tube inside diameter and differential-device size and Beta or area ratio) if the orifice plate is pulled and inspected; the type and location of taps (flange or pipe, upstream or downstream static tap); atmospheric pressure used to offset the static-pressure pen, if applicable; mechanical recorder data (make, model, and differential pressure, static pressure, and temperature element ranges); the normal operating points for differential pressure, static pressure, and flowing temperature; verification points (as-found and applied) for each element; verification points (as-left and applied) for each element, if a calibration was performed; names, contact information, and affiliations of the person performing the verification and any witness, if applicable; and remarks, if any.

The purpose of this documentation is to: (1) Identify the FMP that was verified; (2) Ensure that the operator adheres to the proper verification frequency; (3) Ascertain that the verification/calibration was performed according to the requirements established in § 3175.92(a) through (c), as applicable; (4) Determine the amount of error in the differential-pressure, static-pressure, and temperature pens; (5) Verify the proper offset of the static pen, if applicable; and (6) Allow the determination of flow rate error. The rule includes the documentation requirement for the normal operating points to allow the

BLM to confirm that the proper points were verified and to allow error calculation based on the applicable verification point. The rule requires the primary-device documentation because the primary device is pulled and inspected at the same time that the operator performs a mechanical-recorder verification. Although the BLM did not receive any comments on this section, it added language that the primary device data are only required if the primary device is pulled and inspected during the verification. For very-low- and low-volume FMPs, operators must inspect the primary device every 12 months and every 6 months, respectively. However, for mechanical recorders, verifications are required every 6 months and every 3 months, respectively. Therefore, the operator is only required to pull and inspect the primary device every other time they perform a verification.

§ 3175.92(e)

Proposed § 3175.92(e) would have required the operator to notify the AO at least 72 hours before verification of the recording device. A 72-hour notice would be sufficient for the BLM to rearrange schedules, as necessary, to allow the AO to be present at the verification.

The BLM received a few comments stating that the 72-hour notification would require a great deal of coordination. The BLM agrees with this comment and has included an alternative to submit a monthly or quarterly verification schedule to the AO. The submittal of monthly or quarterly schedules in lieu of the 72-hour notice is already common practice in many field offices.

§ 3175.92(f)

Proposed § 3175.92(f) would have required the operator to correct flow-rate errors that are greater than 2 Mcf/day, if they are due to the chart recorder being out of calibration, by submitting amended reports to ONRR. The 2 Mcf/day flow-rate threshold would eliminate the need for operators to submit – and the BLM to review – amended reports on low-volume meters, where a 2 percent error (as required under Order 5) does not constitute a sufficient volume of gas to justify the cost of processing amended reports. The BLM derived the 2 Mcf/day threshold by multiplying the 2-percent threshold in Order 5 by 100 Mcf/day, which is the maximum flow rate that would have been allowed to be measured with a chart recorder in the proposed rule. Very-low-volume FMPs are exempt from this requirement because the volumes are so small that even relatively large errors discovered during the verification process would not result in significant lost royalties or otherwise justify the costs involved in producing and reviewing amended reports. For example, if an operator were to discover that an FMP measuring 15 Mcf/day is off by 10 percent (a very large error based on the BLM's experience) while performing a verification under this section, that would amount to a 1.5 Mcf/day error which, over a month's period, would be 45 Mcf. At $4 per Mcf, that error could result in an under- or over-payment in royalty of $22.50. It could take several hours for the operator to develop and submit amended OGORs and it could take several hours for both the BLM and ONRR to review and process those reports.

This paragraph also defines the points that are used to determine the flow-rate error. Calculated flow-rate error will vary depending on the verification points used in the calculation. The normal operating points must be used because these points, by definition, represent the flow rate normally measured by the meter.

Although the BLM did not receive comments on this section, an example is added to clarify the flow-rate error correction. The BLM added the example because this calculation tends to cause confusion among both the BLM staff and industry. The BLM also changed the 2 Mcf/day threshold to "2 percent or 2 Mcf/day, whichever is greater." In the proposed rule, the low-/high-volume threshold was 100 Mcf/day; therefore, for a low-volume FMP, a flow rate error of 2 Mcf/day would always have been at or above 2 percent of the total flow rate. However, in the final rule, the low-/high-volume threshold was raised to 200 Mcf/day. For average flow rates between 100 Mcf/day and 200 Mcf/day, which can now be measured with a mechanical recorder, a fixed threshold of 2 Mcf/day would be less than 2 percent of the flow rate. Therefore, the BLM added the 2 percent threshold to be consistent with the requirements for EGM systems (§ 3175.102(g)).

§ 3175.92(g)

Section 3175.92(g) requires verification equipment to be certified at least every 2 years. The purpose of this requirement is to ensure that the verification or calibration equipment meets its specified level of accuracy and does not introduce significant bias into the field meter during calibration. Two-year certification of verification equipment is typically recommended by the verification equipment manufacturer, and therefore, this does not represent a major change from existing procedures. This paragraph also requires that proof of certification be available to the BLM and sets minimum standards as to what the documentation must include. The BLM did not receive any comments on this paragraph.

§ 3175.93 – Integration statements

Section 3175.93 establishes minimum standards for chart integration statements. The purpose of requiring the information listed is to allow the BLM to independently verify the volumes of gas reported on the integration statement. Currently, the range of information available on integration statements varies greatly. In addition, many integration statements lack one or more items of critical information necessary to verify the reported volumes. The BLM is not aware of any industry standards that apply to chart integration.

The BLM received one comment stating that the time of retention is not mentioned. The BLM did not make any changes to the rule based on this comment. Retention time is defined in 43 CFR 3170.7.

§ 3175.94 – Volume determination

Section 3175.94(a) establishes the methodology for determining volume from the integration of a chart. The methodology includes the adoption of the equations published in API 14.3.3 or AGA Report No. 3 for flange-tapped orifice plates. Under this rule, operators using mechanical recorders have the option to continue using the older AGA Report No. 3 flow equation. (Operators using EGM systems, on the other hand, are required to use the flow equations in API 14.3.3 (see § 3175.103.))

There are three primary reasons for allowing mechanical recorders to use a less strict standard. First, chart recorders, unlike EGM systems, are restricted to FMPs measuring 200 Mcf/day or less. Therefore, any errors caused by using the older 1985 flow equation will not have nearly as significant an effect on measured volume or royalty as for a high- or very-high-volume meter. Second, the BLM estimates that only 10 to 15 percent of FMPs still use mechanical recorders, and this number is declining steadily. This fact, combined with the 200 Mcf/day flow rate restriction, means that only a small percentage of gas produced from Federal and Indian leases is measured using a mechanical recorder, significantly lowering the risk of volume or royalty error as a result of using the older 1985 equation. Third, it may be economically burdensome for a chart integration company to switch over to the new API 14.3.3 flow equations because much of the equipment and procedures used to integrate charts was established before the revision of AGA Report No. 3. In the proposed rule, the BLM sought data on the cost for chart integration companies to switch over to the new API 14.3.3 flow rate. The BLM did not receive any such data.

There are two variables in the API 14.3.3 flow equation that have changed since 1985. The current API equation includes a more accurate curve fit for determining the discharge coefficient as a function of Reynolds number, Beta ratio, and line size. Further, the gas expansion factor was changed based on a more rigorous screening of valid data points. The current flow equation also requires an iterative calculation procedure instead of an equation that can be solved directly by hand, providing a more accurate flow rate. The difference in flow rate between the two equations, given the same input parameters, is less than 0.5 percent in most cases.

While API 14.3.3 provides equations for calculating instantaneous flow rate, it is silent on determining volume. Therefore, the methodology presented in API 21.1 for EGM systems is adopted in this section for volume determination. This methodology is generally consistent with existing methods for chart integration and, as such, should not require any significant modifications. For primary devices other than flange-tapped orifice plates, the BLM would approve, based on the PMT's recommendation, the equations that would be used for volume determination.

The BLM received one comment that supported chart integration companies switching to the 1992/2013 volume calculation. The BLM did not make any changes to the rule based on this comment as there was no change requested.

Section 3175.94(a)(3) defines the source of the data that goes into the flow equation. The BLM did not receive any comments on this requirement.

Section 3175.94(b) establishes a standard method for determining atmospheric pressure used to convert pressure measured in psig to units of psia, which is used in the calculation of flow rate. Any error in the value of atmospheric pressure will cause errors in the calculation of flow rate, especially in meters that operate at low pressure. This rule eliminates the use of a contract value for atmospheric pressure because contract provisions are not always in the public interest and do not always dictate the best measurement practice. A contract value that is not representative of the actual atmospheric pressure at the meter will cause measurement bias, especially in meters where the static pressure is low – a condition that is common at FMPs.

This rule also eliminates the option of operators measuring actual atmospheric pressure at the meter location for mechanical recorders. Instead, atmospheric pressure must be determined from an equation or table (see appendix A to this subpart) based on elevation. Atmospheric pressure is used in one of two ways for a mechanical recorder. First, the static-pressure reading from the chart in psig is converted to absolute pressure during the integration process by adding atmospheric pressure to the static pressure reading. Or, second, the static pressure pen can be offset from zero in an amount that represents atmospheric pressure. In the second case, the static-pressure line on the chart already has atmospheric pressure added to it and no further corrections are made during the integration of the charts. The static-pressure element in a chart recorder is a gauge pressure device – in other words, it measures the difference between the pressure from the pressure tap and atmospheric pressure. Offsetting the pen does not convert it into an absolute pressure device; it is only a convenient way to convert gauge pressure to atmospheric pressure. If measured atmospheric pressure were allowed, the measurement could be made when, for example, a low-pressure weather system was over the area. The measured atmospheric pressure in this example would not be representative of the average atmospheric pressure and would bias the measurements to the low side. This is much more critical in meters operating at low pressure than in meters operating at high pressure. The BLM believes that operators rarely use measured atmospheric pressure to offset the static pressure; therefore, this requirement would have no significant impact on current industry practice. The treatment of atmospheric pressure for mechanical recorders is different than it is for EGM systems because many EGM systems measure absolute pressure, whereas all mechanical recorders are gauge-pressure devices. Please see the discussion of § 3175.102(a)(3) for further analysis.

The equation to determine atmospheric pressure from elevation ("U.S. Standard Atmosphere," National Aeronautics and Space Administration, 1976 (NASA-TM-X-74335)), prescribed in appendix A to this subpart, produces similar results to the equation normally used for atmospheric pressure for elevations less than 7,000 feet mean sea level (see Figure 3). The BLM did not receive any comments on the change in how atmospheric pressure must be calculated.

§ 3175.100 – Electronic gas measurement (secondary and tertiary device)

Section 3175.100 adopts API 21.1, Subsection 7.3, regarding EGM equipment commissioning; API 21.1, Section 9, regarding access and data security; and API 21.1, Subsection 4.4.5, regarding the no-flow cutoff. The BLM has reviewed these sections and believes they are appropriate for use at FMPs. The existing statewide NTLs referenced similar sections in the previous version of API 21.1 (1993); therefore, this is not a significant change from existing requirements.

The BLM received several comments objecting to the application of API 21.1 to low- and very-low-volume FMPs due to its complexity and the difficulty of implementing it for wellhead measurement. The BLM recognizes the recommendations of API 21.1 as industry standards for accurate measurement of natural gas. These consensus standards are developed by operators, manufacturers, purchasers, and other recognized experts within the oil and gas industry and approved by API voting members. The authors of API 21.1 did not include any limitations for the use of the standard based on a specific application or average flow rate through the meter, nor did the commenters provide any justification as to why API 21.1 was too complex and difficult to implement on low- and very-low-volume FMPs. In addition, wellhead measurement is not a requirement of the BLM. The BLM requirement is only that measurement of gas must occur prior to removal or sales from the lease, unit PA, or CA, unless otherwise approved by the AO. Therefore, if an operator believes that API 21.1 is too complex or difficult to use for wellhead measurement, they could combine the production from multiple wells within a lease, CA, or unit PA and measure the combined stream. Combining production from multiple wells within a single lease, unit PA, or communitized area is not considered commingling for production accounting purposes and does not require BLM approval (see definition of commingling in § 3170.3(a)). The BLM did not make any changes as a result of this comment.

The BLM received a comment indicating that the description of the acronyms at the bottom of Table 1 to § 3175.100, Standards for Electronic Gas Measurement Systems, may suggest that all very-high-volume FMP requirements will be subject to immediate assessments for non-compliance. The commenter suggested adding a comma and asterisk after the phrase "Very-high-volume FMP" to delineate the acronym definition from the note on immediate assessments. The BLM agrees with this comment and changed this language to indicate that only those requirements with a superscript number 1 (^{1}) following the subject in the table are intended to have immediate assessment for non-compliance.

§ 3175.101 – Installation and operation of electronic gas measurement systems

§ 3175.101(a)

Section 3175.101(a) sets requirements for manifolds and gauge lines. The requirements regarding gauge lines for EGM systems are identical to the requirements for gauge lines for mechanical recorders. The comments that the BLM received on gauge lines are also the same for both EGM systems and mechanical recorders. Please see the discussion of gauge line requirements and comments on these requirements under § 3175.91(a).

§ 3175.101(b) and (c)

Section 3175.101(b) and (c) specify the minimum information that the operator must maintain onsite for an EGM system and make available to the BLM for inspection. The purpose of the data requirements in these sections is to allow BLM inspectors to:

(1) Verify the flow-rate calculations being made by the flow computer;

(2) Compare the daily volumes shown on the flow computer to the volumes reported to ONRR;

(3) Determine the uncertainty of the meter;

(4) Determine if the Beta ratio is within the required range;

(5) Determine if the upstream and downstream piping meets minimum standards;

(6) Determine if the thermometer well is properly placed;

(7) Determine if the flow computer software version and transducer makes, models, and URLs have been reviewed by the PMT and approved by the BLM;

(8) Verify that the primary device has been inspected at the required frequency; and

(9) Verify that the transducers have been verified at the required frequency.

Section 3175.101 paragraphs (b)(1) through (3) requires that each EGM system include a display that is accessible to the BLM, and that shows the units of measure for each variable.

The BLM received a few comments to the proposed requirement in § 3175.101(b)(1). The commenters objected to the need for a display. The BLM did not make any changes to the rule based on these comments. The BLM believes the displayed information is required in order to verify that the flow computer is functioning properly. The BLM uses the displayed information for several purposes, including to independently check the flow-computer calculations, to determine average values of differential and static pressure in order to enforce uncertainty requirements, to compare the displayed volume to reported volume, and to determine the normal operating points for verification. The statewide NTLs, which have been in place for at least 7 years (12 years for Wyoming), all require a display, so this requirement is not new.

The BLM received one comment regarding the requirement in § 3175.101(b)(2) that the display be onsite and in a location that is accessible to the AO. The commenter objected to the requirement of accessibility by the AO if the meter house is locked. The BLM did not make any changes to the rule based on this comment. The BLM must have immediate access to the EGM display. Although some operators have offered to provide BLM inspectors with keys or combinations to locks, the BLM has determined after years of experience that this rarely works well. During the course of a year, a BLM inspector has to inspect thousands of FMPs owned by dozens of different operators. It is unworkable for BLM inspectors to maintain a list of lock combinations and keys, both of which often change over the course of time. The BLM does not believe that it is unreasonable to ask for ready access to the EGM display. Again, this requirement is essentially the same as the requirement for the display to be accessible to the BLM in the statewide NTLs.

The BLM received one comment regarding the proposed requirement in § 3175.101(b)(3) to include units of measure for each required variable in the display. The commenter objected to this requirement and proposed an alternative to post the units on a placard or card. The BLM did not make any changes to the rule based on this comment. The BLM believes that the units of measure must be with the variables in the display because they can change when a flow computer is replaced or reconfigured. The units of measure are critical when verifying the flow-computer calculations in the field. Based on the BLM's experience, virtually all flow computers are capable of displaying the units of measure; therefore, the BLM believes this is a reasonable requirement.

Proposed § 3175.101(b)(4) would have required the display to contain 13 items, including the FMP number, software version, instantaneous flow data (differential pressure, static pressure, flowing temperature, and flow rate), previous day volume and flow time, previous day average flowing data (differential pressure, static pressure, and flowing temperature), relative density, and primary device information (e.g., orifice bore diameter).

The BLM received several comments on this section, which stated that most legacy and several current models of flow computers cannot accommodate 13 lines due to software limitations and suggested that some of the required information could be posted onsite instead of being part of the display. The BLM agrees with these comments and has reduced the amount of information that must be displayed by the flow computer from 13 lines in the proposed rule to 6 lines of information in the final rule. The final rule no longer requires the FMP number (see discussion below), the relative density, or the primary device information as part of the display if this information is posted onsite. The BLM eliminated the requirement to display or post the previous day's flow time. In addition, the previous day's average differential pressure, average static pressure, and average flowing temperature do not have to be displayed if the operator posts an hourly or daily QTR (see § 3175.104(a)) that is no more than 31 days old onsite and accessible to the AO. Posting the previous day's average values will still allow the BLM to determine the normal operating points of differential pressure, static pressure, and temperature, in order to perform an uncertainty calculation and determine the normal operating points for verification.

The BLM also received numerous comments regarding the proposed requirement in § 3175.101(b)(4)(i) to include the FMP number or, if an FMP number has not yet been assigned, a unique meter-identification number in the display. The commenters stated that most EFCs are not capable of handling an 11-digit FMP number in the display. The commenters suggested only providing the FMP number during calibration, at the time of audit, or making the FMP number available by posting it onsite. The BLM agrees with these comments and has removed the proposed requirement to display the FMP number on the electronic display. Instead, the operator may post a unique meter ID number (which could include the FMP number) at the FMP. The BLM also added the term "unique meter ID number" to the definitions in § 3170.

Section 3175.101(c) sets requirements for information that must be onsite, but not necessarily on the EGM system display. The information in the proposed rule included the elevation, meter tube diameter, information regarding the flow conditioner or 19-tube-bundle flow straightener (if installed), information regarding the transducers and flow computer, static pressure tap location, and last inspection dates for both the primary and secondary devices.

The BLM did not receive any comments on § 3175.101(c). However, the BLM did add additional items to this list based on comments on § 3175.101(b), including a unique meter ID number, the relative density of the gas, and primary device information.

§ 3175.101(d)

Section 3175.101(d) requires the differential pressure, static pressure, and flowing temperature transducers to be operated within the lower and upper calibrated limits of the transducer. Inputs that are outside of these limits are subject to higher uncertainty and if the transducer is over-ranged, the readings may not be recorded. The term “over-ranged” means that the pressure or temperature transducer is trying to measure a pressure or temperature that is beyond the pressure or temperature it was designed or calibrated to measure. In some transducers – typically older ones – the transducer output will not exceed the maximum value for which it was calibrated, even when the pressure being measured exceeds that value. For example, if a differential-pressure transducer that has a URL of 250 inches of water is measuring a differential pressure of 300 inches of water, the transducer may output only 250 inches of water. This results in loss of measured volume and royalty. Many newer transducers will continue to measure values that are over their calibrated range; however, because the transducer has not been calibrated for these values, the uncertainty may be higher than the transducer specification indicates. Many of these newer transducers will not output a value that exceeds the URL of that transducer, however.

The BLM received one comment in response to § 3175.101(d) that suggested an exception for wells using a plunger lift system. A plunger lift is installed on a well to suppress flow from the well until enough pressure builds up to lift accumulated liquids out of the wellbore. When the well pressure reaches this threshold, the plunger releases and a surge of flow – both liquids and gases – comes to the surface. This results in a spike in the gas flow through the meter, which causes a corresponding spike in the differential pressure at the meter. It is often difficult to size an orifice plate and differential-pressure transducer to accurately record both the spike in flow, which typically lasts only several seconds, and the lower differential pressure for the remainder of the plunger cycle. The commenter suggested that the BLM should allow the differential-pressure transducer associated with a plunger lift system to exceed the URL by 150 percent for 1 minute. The rationale for this, as stated by the commenter, is that under the transducer testing protocol (see § 3175.133(e)), the transducer must be tested at 150 percent of URL for at least 1 minute; therefore, the BLM should accept over-range operation of the differential-pressure transducer for 1 minute because this condition has been tested. The commenter stated that the increased uncertainty of a transducer operating in an over-range condition could be derived from the testing done under § 3175.133(e).

The BLM believes that the commenter has misinterpreted the intent of the testing protocol. The testing protocol does require an "over-range effects" test where the transducer is operated at 150 percent of its URL for at least 1 minute. However, the purpose of this test is to see if, or how much, the over-ranging affects the calibration of the transducer under normal operation when the reading is below the upper calibrated limit. In some transducers, a brief over-ranging can cause the calibration of the transducer to shift, which affects all of the transducer's readings. This testing does not determine the accuracy to which an over-range pressure is recorded or if the over-range pressure is recorded at all, it only determines how an over-range condition affects the accuracy of the transducer when it is operated within its upper calibrated limit. Also, the BLM is grandfathering transducers that are used at FMPs as of [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] from going through the testing protocol in § 3175.130. While the manufacturer must still submit the data from whatever testing they did in order to get BLM approval, this testing may not have included the over-range-effects test to which the commenter refers.

The BLM agrees that plunger lifts can cause measurement issues as described previously and added a provision to § 3175.101(d) to allow the differential pressure to exceed the upper calibrated limit for brief periods of time if approved by the BLM. The BLM does not believe the differential pressure should ever exceed the URL, because in some transducers differential pressures exceeding the URL are not recorded and included in the calculation of volume. Although operation of the differential-pressure transducer over the upper calibrated limit may exceed the uncertainty specification of the transducer, the BLM believes that this will not significantly degrade the uncertainty of the volume calculation if these instances are brief. The BLM did not make any changes regarding the commenter's suggestion to allow the exceedance for 1 minute. Although the 1-minute timeframe is a test condition in §3175.133(e)(1), this is not relevant for normal operation of the transducer. In addition, a specific timeframe would be virtually impossible for the BLM to enforce.

§ 3175.101(e)

Section 3175.101(e) requires the flowing temperature of the gas to be continuously recorded on all FMPs except on very-low-volume FMPs. Flowing temperature is needed to determine flowing gas density, which is critical to determining flow rate and volume. Very-low-volume FMPs would be exempt from this requirement because the potential effect on royalty would be minimal and the BLM's experience suggests that the costs would outweigh potential royalty. For very-low-volume FMPs, any errors introduced by using an estimated temperature in lieu of a measured temperature would not have a significant impact on royalties. The BLM did not receive any comments on this paragraph.

§ 3175.102 – Verification and calibration of electronic gas measurement systems

§ 3175.102(a)

Section 3175.102(a) includes several specific requirements for the verification and calibration of transducers following installation and repair. This differentiates the procedures that are specific to this type of verification from the procedures required for a routine verification under § 3175.102(c). The primary difference between § 3175.102(a) and (c) is that an as-found verification is not required if the meter is being verified following installation or repair.

Section 3175.102(a)(1) requires a leak test before performing a verification or calibration. Please see the previous discussion regarding § 3175.92(a)(1) for further explanation of leak testing.

The BLM received one comment in response to this requirement stating support for the proposed requirement for a leak test prior to performing verification of equipment. No change was requested. The BLM did not make any changes to the rule based on this comment.

Section 3175.102(a)(2) requires a verification to be done at the points required by API 21.1, Subsection 7.3.3 (zero percent, 25 percent, 50 percent, 100 percent, 80 percent, 20 percent, and zero percent of the calibrated span of the differential-pressure and static-pressure transducers, respectively). This includes more verification points than are required for a routine verification described in § 3175.102(c). The purpose of requiring more verification points in this section is: (1) For new installations, the normal operating points for differential and static pressure may not be known because of a lack of historical operating information; and (2) A more rigorous verification is required to ensure that new or repaired equipment is working properly between the lower and upper calibrated limits of the transducer.

The BLM received several comments stating that the proposed rule implies that an operator could not recalibrate the transducer to bring it into compliance and that the only solution is to replace the transducer. The BLM does not agree with these comments. Section 3175.102(a)(2) states: "If any of these as-left readings vary from the test equipment by more than the tolerance determined by API 21.1, Subsection 8.2.2.2, Equation 24 (see § 3175.30), then that transducer must be replaced and retested under this paragraph." The term "as-left," as defined in § 3175.10, means: "The reading of a mechanical or electronic transducer when compared to a certified test device, after making adjustments to the transducer, but prior to returning the transducer to service." An operator must perform an as-left verification prior to returning the meter to service if the transducer was calibrated. The as-left verification assumes that the operator has done whatever they could to achieve the tolerances of API 21.1, Subsection 8.2.2.2, Equation 24, including multiple calibrations or recalibrations. The BLM did not make any changes to the rule based on these comments.

Other commenters stated that older meters are incapable of verification at six points and should be grandfathered, and that the additional verification at the proposed points would increase time and cost without improving accuracy. The BLM does not agree. There are no limits to the number of verification points that a flow computer can provide.

An operator can obtain a verification point by comparing the reading from the test equipment with the reading from the flow computer. While some flow computers may have limitations on the number of verification points that the event log will record, the BLM does not require the flow computer to log verification points. The BLM did not make any changes to the rule based on this comment.

Another commenter said the proposed rule did not allow for a working-pressure zero adjustment and, as a result, a transmitter could appear to be out of calibration when it is not. A working-pressure zero adjustment compares the differential-pressure transducer's reading, when line pressure is applied to both sides of the transducer, to the transducer's reading when atmospheric pressure is applied to both sides. This difference is then applied to all readings determined from a differential-pressure verification, which is done at atmospheric pressure. The BLM disagrees with this comment. Section 3175.102(a)(2) is specific to new FMPs or to transducers that the operator has replaced or repaired. Because the operator has just installed this transducer and it has not yet been subjected to working pressure, there would be no way do a working-pressure zero adjustment. Section 3175.102(a)(4) requires the operator to re-zero the transducer prior to returning it to service if the difference between atmospheric-pressure zero and working-pressure zero is greater than the tolerance defined in Equation 24. The BLM did not make any changes to the rule based on this comment.

Proposed § 3175.102(a)(3) would have required the operator to calculate the value of atmospheric pressure used to calibrate an absolute-pressure transducer from elevation using the equation or table given in Appendix A to this subpart, or to be based on a barometer measurement made at the time of verification for absolute-pressure transducers in an EGM system. Under this rule, use of the value for atmospheric pressure defined in the buy/sell contract is not allowed unless it meets the requirements stated in this section. The BLM is eliminating the use of a contract value for atmospheric pressure because contract provisions are not always in the public interest, and they do not always dictate the best measurement practice. A contract value that is not representative of the actual atmospheric pressure at the meter will cause measurement bias, especially in meters where the static pressure is low. If a barometer is used to determine the atmospheric pressure, the barometer must be certified by the National Institute of Standards and Technology (NIST) and have an accuracy of ±0.05 psi, or better. This will ensure the value of atmospheric pressure entered into the flow computer during the verification process represents the true atmospheric pressure at the meter station.

This requirement is different from the requirements in § 3175.94(b) for the treatment of atmospheric pressure in connection with mechanical recorders. The difference results from the design of the pressure measurement device – whether it is a gauge pressure device or an absolute pressure device. A gauge pressure device measures the difference between the applied pressure and the atmospheric pressure. An absolute pressure device measures the difference between the applied pressure and an absolute vacuum.

The use of a barometer to determine atmospheric pressure is allowed only when calibrating an absolute pressure transducer. It is not allowed for gauge pressure transducers. Because all mechanical recorders are gauge pressure devices (even if the pen has been offset to account for atmospheric pressure), the use of a barometer to establish atmospheric pressure is not allowed.

The BLM received several comments in response to this proposed requirement. One commenter stated that this does not allow for local changes in barometric pressure. The BLM agrees that a calculation of atmospheric pressure would not account for local changes in barometric pressure, presumably due to weather systems in the area. However, the additional uncertainty caused by weather systems is easy to estimate and include in the calculation of overall uncertainty (the BLM uncertainty calculator does this). Another commenter proposed using the barometric pressure reported by the National Weather Service if a barometer was not available. The BLM disagrees because a barometric pressure reported by the National Weather Service is generally corrected to mean sea level and does not represent the true atmospheric pressure at the FMP location. Even if the National Weather Service, or other weather service, were to provide a true uncorrected barometric pressure, it would be specific to the elevation of an airport or other fixed location and would most likely not represent the true atmospheric pressure at the FMP location. The BLM did not make any changes to the rule based on these suggestions.

One commenter suggested the option of using a static pressure calibration device that applies absolute pressures to the static-pressure transducer (virtually all calibration devices in use today apply gauge pressure to the static-pressure transducer), as long as it is twice as accurate as the transducer under calibration. The BLM agrees with this suggestion and added this option to § 3175.102(a)(3). However, the absolute pressure calibration device would not have to be twice as accurate as the transducer being calibrated, as long as it meets the requirements of a calibration device in § 3175.102(h).

Proposed § 3175.102(a)(4) would have required the operator to re-zero the differential-pressure transducer under working pressure before putting the meter into service. Differential-pressure transducers are verified and calibrated by applying known pressures to the high side of the transducer while leaving the low side vented to the atmosphere. When a differential-pressure transducer is placed into service, the transducer is subject to static (line) pressure on both the high side and the low side (with small differences in pressure between the high and low sides due to flow). The change from atmospheric-pressure conditions to static-pressure conditions can cause all the readings from the transducer to shift, usually by the same amount.

Typically, the higher the static pressure is, the more shift occurs. Zero shift can be minimized by re-zeroing the differential-pressure transducer when the high side and low side are equalized under static pressure. The re-zeroing proposed in this section would have been a new requirement that would eliminate measurement errors caused by static-pressure zero-shift of the differential-pressure transducer. Re-zeroing is recommended in API 21.1, Subsection 8.2.2.3, but not required. The BLM proposed to require it here. The BLM received several comments in response to the proposed requirement, objecting to re-zeroing if the transducer's reading did not change more than the tolerance required in API 21.1, Subsection 8.2.2.2, Equation 24, when subjected to working pressure. The BLM generally agrees with this comment. The BLM added language that requires re-zeroing the transducer only if the absolute value of the transducer reading is greater than the reference accuracy of the transducer, expressed in inches of water column. The BLM did not reference Equation 24 because test equipment is not used to check the zero shift due to working pressure. If the accuracy of the verification equipment is removed from

Equation 24, the equation reduces to the reference accuracy of the transducer, which is the language the BLM used in making this change.

§ 3175.102(b)

Section 3175.102(b) establishes requirements for how often a routine verification must be performed where the minimum frequency, in months, is shown in Table 1 to § 3175.100. The proposed rule would have required a verification every month for very-high-volume FMPs, every 3 months for high-volume FMPs, every 6 months for low-volume FMPs, and every 12 months for very-low-volume FMPs. Because there is a greater risk of measurement error in the volume calculation for a given transducer error at higher-volume FMPs, the proposed rule would have increased the verification frequency as the measured volume increases.

The BLM received several comments in response to this proposed requirement. One commenter stated that they wanted the terminology changed from the number of months between verifications to the number of times per year the verification had to be accomplished. For example, instead of "every 3 months," the requirement should read "quarterly." The BLM did not make any changes to the rule as a result of this comment because the BLM believes the frequency of required verifications given in Table 1 to § 3175.100, is clear as written. In addition, a term such as "quarterly" could be interpreted to mean that a routine verification could be done at the beginning of one quarter and at the end of another quarter, essentially doubling the time between verifications that the BLM intended.

Several commenters stated that the calibration frequency was excessive on very-high-volume FMPs while other commenters stated that the calibration frequency should be increased to every 6 months on very-low-volume FMPs. The BLM agrees that modern equipment does not drift significantly and calibration can cause more error than it solves due to human error during the calibration process. As a result, the BLM changed the required verification frequency for very-high-volume FMPs from once every month to once every 3 months. The BLM did not change the verification frequency for very-low-volume FMPs because it is based on an economic model that does not justify a calibration frequency higher than annual.

§ 3175.102(c)

Section 3175.102(c) adopts the procedures in API 21.1, Subsection 8.2, for the routine verification and calibration of transducers with several additions and clarifications. The primary difference between § 3175.102(a) and (c) is that an as-found verification is required for routine verifications in § 3175.102(c).

Section 3175.102(c)(1) requires a leak test before performing a verification. A leak test is not specified in API 21.1, Subsection 8.2; however, the BLM believes that performing a leak test is critical to obtaining accurate measurement. Please see the previous discussion of § 3175.92(a)(1) for further explanation of leak testing.

The BLM received one comment in response to the proposed requirement in § 3175.102(c)(1) on performing a leak test. The commenter stated that a leak test should not be required on non-regulated pressure sources because leaks are readily detectable without having to perform a leak test. The BLM believes that the commenter is using the term “regulated” pressure source to refer to devices such as deadweight testers. A regulated pressure source could mask a leak because, if a leak were present, it would continuously add air or gas to the system to maintain a constant pressure. In theory, a non-regulated pressure source would not mask a leak. However, a leak could still be masked with a non-regulated pressure source if, for example, the valve on the pressure source is not shut off completely during the calibration. The BLM did not make a change to the rule based on this comment. The BLM believes a leak test is the only definitive way to determine if leaks are present and it is neither onerous nor time consuming to perform.

Section 3175.102(c)(2) requires that the operator perform an as-found verification at the normal operating point of each transducer. This clarifies the requirements in API 21.1, Subsection 8.2.2.3, which requires a verification at either the normal point or 50 percent of the upper user-defined operating limit. This paragraph also defines how the normal operating point is determined because this is a common point of confusion for operators and the BLM.

The BLM received one comment in response to the proposed requirement in § 3175.102(c)(2) on the verification at the normal operating point of each transducer. The commenter requested clarification on how close they have to be to the normal point when verifying a transducer. For example, the commenter stated that they already do a 10-point verification on the differential-pressure transducer and wondered if that would be sufficient to comply with the normal point requirement. The BLM agrees with the commenter that clarification is needed, and added clarification in the final rule that for differential and static-pressure transducers, the pressure applied to the transducer for this verification must be within five percentage points of the normal operating point, while for the temperature transducer, the water bath or test-thermometer well must be within 20°F of the normal operating point.

In addition to making the changes to this section in response to comments, the BLM added a new § 3175.102(c)(3) that requires operators to replace transducers when the as-found verification exceeds the manufacturer's specification for stability or drift, as adjusted for static pressure and ambient temperature, on two consecutive verifications. The BLM added this requirement in lieu of the long-term stability test that was eliminated from § 3175.133(g). Because the BLM does not have any way to verify the long-term stability specification provided by the manufacturer without testing, the BLM will enforce the manufacturer's specifications during field verification. There is no reason that a properly functioning transducer should be outside of the stability or drift specification once adjustments for static pressure (on differential-pressure transducers) and ambient temperature are factored out. Manufacturer's specifications include both static pressure effects on differential-pressure transducers and ambient temperature effects. The BLM plans to add the capability of determining the maximum allowable drift to the BLM uncertainty calculator to make this requirement easier to enforce.

Section 3175.102(c)(4) also requires that the operator perform an as-left verification at the normal operating point of each transducer. The BLM did not receive any comments on this paragraph.

Section 3175.102(c)(5) (§ 3175.102(c)(4) in the proposed rule) requires the operator to correct the as-found values for differential pressure taken under atmospheric conditions to working pressure values based on the difference between working-pressure zero and the zero value obtained at atmospheric pressure. Please see the previous discussion of proposed § 3175.102(a)(4) for further explanation of zero shift. API 21.1, Subsection 8.2.2.3, recommends that this correction be made, but does not require it. API also provides a methodology for the correction. The correction methodology in API 21.1, Annex H, is required in this section. The BLM did not receive any comments on this paragraph.

Section 3175.102(c)(6) (§ 3175.102(c)(5) in the proposed rule) adopts the allowable tolerance between the test device and the device being tested as stated in API 21.1, Subsection 8.2.2.2. This tolerance is based on the reference uncertainty of the transducer and the uncertainty of the test equipment.

The BLM received several comments in response to this proposed requirement. One commenter stated that the verification tolerances in API 21.1, Subsection 8.2.2.2, are complex and restrictive and that the BLM should not require operators to follow it. The BLM disagrees. The purpose of establishing a verification tolerance is to ensure that a calibration is only required when the transducer readings have drifted outside of the combined accuracy of both the transducer and the test equipment. The API requirement for verification tolerance is similar to the verification tolerance in the BLM statewide NTLs for EFCs. Because API 21.1 no longer requires the test equipment to be twice as accurate as the equipment being tested, the added uncertainty of the test equipment can no longer be ignored and must be included in the determination of verification tolerance. The BLM did not make any changes to the rule based on this comment.

Another commenter suggested tying the verification tolerance of the temperature transmitter to the uncertainty of the temperature transmitter rather than establishing a set value of 0.5°F as required in the proposed rule. The BLM agrees that tying the verification tolerance to the uncertainty is consistent with the requirement for differential and static-pressure transducers. The BLM added that the verification tolerance for temperature transmitters is equivalent to the uncertainty of the temperature transmitter or 0.5°F, whichever is greater.

Section 3175.102(c)(7) (§ 3175.102(c)(6) in the proposed rule) clarifies that all required verification points must be within the verification tolerance before returning the meter to service. This requirement is implied by API 21.1, Subsection 8.2.2.2, but is not clearly stated. The BLM did not receive any comments on this paragraph.

Proposed § 3175.102(c)(8) (§ 3175.102(c)(7) in the proposed rule) would have required the differential-pressure transducer to be zeroed at working pressure before returning the meter to service. This is implied by API 21.1, Subsection 8.2.2.3, but not required. Refer to the discussion of zero shift under § 3175.102(a)(4) for further information.

The BLM received several comments in response to this proposed requirement. The commenters stated that it was an unnecessary step to re-zero the differential transducer if it was already reading zero. The BLM agrees with the commenters and changed the proposed rule to require operators to re-zero the differential-pressure transducer only if the absolute value of the transducer reading under pressure is greater than the reference accuracy of the transducer, expressed in inches of water column. See the discussion under § 3175.102(a)(4).

§ 3175.102(d)

Section 3175.102(d) allows for redundancy verification in lieu of a routine verification under § 3175.102(c). Redundancy verification was added to the current version of API 21.1 as an acceptable method of ensuring the accuracy of the transducers in lieu of performing routine verifications. Redundancy verification is accomplished by installing two EGM systems on a single differential flow meter and then comparing the differential pressure, static pressure, and temperature readings from the two EGM systems. If the readings vary by more than a set amount, both sets of transducers would have to be calibrated and verified. Operators have the option of performing routine verifications at the frequency required under § 3175.102(b) or employing redundancy verification under this paragraph. Operators may realize cost savings by adopting redundancy verification, especially on high- or very-high-volume FMPs. The rule adopts API 21.1, Subsection 8.2, procedures for redundancy verifications with several additions and clarifications as follows.

Section 3175.102(d)(1) requires the operator to identify separately the primary set of transducers from the set of transducers that is used as a check. This requirement allows the BLM to know which set should be used for auditing the volumes reported on the OGOR.

Section 3175.102(d)(2) requires the operator to compare the average differential pressure, static pressure, and temperature readings taken by each transducer set every calendar month. API 21.1, Subsection 8.2, does not specify a frequency at which this comparison should be done.

Section 3175.102(d)(3) establishes the tolerance between the two sets of transducers that will trigger a verification of both sets of transducers under § 3175.102(c). API 21.1 does not establish a set tolerance. This section also requires the operator to perform a verification within 5 days of discovering the tolerance has been exceeded.

The BLM did not receive any comments on § 3175.102(d).

§ 3175.102(e)

Section 3175.102(e) establishes requirements for retaining documentation related to each verification and calibration. This section also establishes the information that the operator must retain onsite for redundancy verifications. Section 3175.102(e)(1)(i) refers to § 3170.7 (§ 3170.6 in the proposed rule), which lists the information that operators must include on all source records.

The BLM received a few comments in response to the proposed requirement in § 3175.102(e). The commenters stated that the retention of the FMP number required in proposed § 3170.6 (§ 3170.7 in the final rule) would take some time to implement, and that the citation to § 3170.6 should be changed to § 3170.7. The BLM agrees with the commenters, corrected the citations, and, in final subpart 3170, changed § 3170.7 to require operators to use either an FMP number or the lease, unit PA, or CA number, along with a unique meter identification number, on verification documentation. (Operators still have the option of using the FMP number.)

The BLM also added a provision to the first sentence of this paragraph clarifying that the documentation requirements of this paragraph also apply to transducers that are replaced to ensure that operators document how much in error the broken transducers were prior to replacement.

§ 3175.102(f)

Proposed § 3175.102(f) would have required the operator to notify the BLM at least 72 hours before verification of an EGM system. A 72-hour notice would be sufficient for the BLM to rearrange schedules, as necessary, to be present at the verification.

The BLM received a few comments in response to this proposed requirement. The commenters stated that the 72-hour notification before performing verification would require a great deal of coordination. The BLM agrees with these comments and has included an alternative to submit a monthly or quarterly verification schedule to the AO for routine verifications performed under § 3175.102(c). The submittal of monthly or quarterly schedules in lieu of the 72-hour notice is already common practice in many field offices. For verifications performed after installation or following repair, however, the 72-hour notice requirement in the proposed rule was retained because it would be difficult for operators to schedule these on a monthly or quarterly basis.

§ 3175.102(g)

Proposed § 3175.102(g) would have required correction of flow-rate errors greater than 2 percent or 2 Mcf/day, whichever is less, if the errors are due to the transducers being out of calibration, by submitting amended reports to ONRR. For lower-volume meters, a 2 percent error may represent only a small amount of volume. Assuming the 2 percent error resulted in an underpayment of royalty, the amount of royalty recovered by receiving amended reports may not cover the costs incurred by the BLM or ONRR of identifying and correcting the error. This rule adds an additional threshold of 2 Mcf/day to exempt amended reports on low-volume, small-error FMPs.

The BLM received numerous comments in response to this proposed requirement stating that this would be an onerous requirement and that the term “less” should be changed to “greater.” The BLM agrees with the comments on changing the term “less” to “greater.” That was an oversight in the proposed rule. To further clarify flow rate error volume correction when the date on which the error occurred is unknown, this section refers to an example in § 3175.92(f).

One commenter suggested that volume corrections should only be required when the flow rate error is greater than 2 percent or 100 Mcf/month, whichever is less. The BLM did not make any changes to the rule based on this comment because there was no compelling rationale for this change given by the commenter. The value of 100 Mcf/month is approximately 3 Mcf/day, which is essentially the same as the 2 Mcf/day threshold the BLM adopted in this rule.

Section 3175.102(g) also defines the points that are used to determine the flow rate error. Calculated flow-rate error will vary depending on the verification points used in the calculation. The normal operating points must be used because these points, by definition, represent the flow rate normally measured by the meter. As specified in Table 1 to § 3175.100, very-low-volume FMPs are exempt from this requirement because the volumes are so small that even relatively large errors discovered during the verification process will not result in significant lost royalties, and thus, the process of amending reports would not be worth the costs involved for either the operator or the BLM. Please see the example given in the discussion of § 3175.92(f).

§ 3175.102(h)

Section 3175.102(h)(1) requires verification equipment to be certified at least every 2 years. The purpose of this requirement is to ensure that the verification or calibration equipment meets its specified level of accuracy and does not introduce significant bias into the field meter during calibration. Two-year certification of verification equipment is not required by API 21.1; however, the BLM believes that periodic certification is necessary. This requirement is consistent with requirements in the previous edition of API 21.1 (1993), which was adopted by the statewide NTLs for EFCs. This section also requires that proof of certification be available to the BLM at the time of inspection and sets minimum standards as to what the documentation must include. The minimum documentation standard represents common industry practice.

Section 3175.102(h)(2) adopts language in API 21.1, Subsection 8.4, regarding the accuracy of test equipment. The statewide NTLs, which adopted the standards of API 21.1 (1993), required that the test equipment be at least two times more accurate than the device being tested. The purpose of this requirement was to reduce the additional uncertainty from the test equipment to an insignificant level. Many of the newer transducers being used in the field are of such high accuracy that field test equipment cannot meet the standard of being twice as accurate. Therefore, the current API 21.1 allows test equipment with an uncertainty of no more than 0.10 percent of the upper calibrated limit of the transducer being tested, even if it is not two times more accurate than the transducer being tested. For example, verifying a transducer with a reference accuracy of 0.10 percent of the upper calibrated limit with test equipment that was at least twice as accurate as the device being tested, would require the test equipment to have an accuracy of 0.05 percent or better of the upper calibrated limit of the device being tested. This level of accuracy is very difficult to achieve outside of a laboratory. As a result, API 21.1, Subsection 8.4, and § 3175.102(h) only require the test equipment to have an accuracy of 0.10 percent of the upper calibrated limit of the device being tested. However, because the test equipment is no longer at least twice as accurate as the device being tested (they would both have an accuracy of 0.10 percent in this example), the additional uncertainty from the test equipment is no longer insignificant and must be accounted for when determining overall measurement uncertainty. The BLM will verify the overall measurement uncertainty – including the effects of the calibration equipment uncertainty – by using the BLM uncertainty calculator or an equivalent tool during the witnessing of a meter verification.

The BLM received several comments in response to this proposed requirement. The commenters stated that improvements in the accuracy of transducers are outpacing improvements in the accuracy of test equipment, and it is difficult to find test equipment that is twice as accurate as the transducers under test outside of a laboratory setting. The commenters recommended granting a variance in this situation. The BLM recognizes that many transducers are accurate enough that field test equipment cannot achieve double the accuracy of the transducer under test. That is why the BLM added paragraph (h)(2)(ii) to this section. Paragraph (h)(2)(ii) allows operators to use test equipment with an accuracy of 0.10 percent of the upper calibrated limit of the transducer under test even if it is not twice as accurate as the transducer under test. The additional uncertainty resulting from test equipment that is not at least twice as accurate as the transducer under test is accounted for in the calculation of overall measurement uncertainty. The BLM made no changes based on these comments.

§ 3175.103 – Flow rate, volume, and average value calculation

§ 3175.103(a)

Section 3175.103(a) would have prescribed the equations that must be used to calculate the flow rate for all FMPs. Proposed § 3175.103(a)(1) would have applied to flange-tapped orifice plates and would have represented a change from the statewide EFC NTLs because the NTLs allowed the use of either the API 14.3.3 or the AGA Report No. 3 (1985) flow equation. The proposed rule would not have allowed the use of the AGA

Report No. 3 (1985) flow equation because it is not as accurate as the API 14.3.3 flow equation and can result in measurement bias. The NTLs also allowed the use of either AGA Report 8 (API 14.2) or NX-19 to calculate supercompressibility. The proposed rule would have only allowed API 14.2 because it is a more accurate calculation.

The BLM received several comments in response to this proposed requirement stating that AGA report No. 3 (1992 and 1985) and AGA Report No. 8 (1992) should be allowed since these are very similar to the latest standard and any change to a newer standard would put significant expense upon the operator. The BLM agrees that updating older flow computers with the latest calculation software may be cost prohibitive for low- and very-low-volume FMPs, especially if the manufacturer no longer supports software upgrades. Additionally, the difference in volume calculated with the latest API equations as compared to older versions of the API equations is not that significant for low- and very-low-volume FMPs. For these reasons, the BLM grandfathered low- and very-low-volume FMPs installed prior to the effective date of this rule from having to use the latest API equations. Please see the discussion under § 3175.61.

The BLM has incorporated AGA Report No. 8 (1992) in the final rule; therefore, any flow computer using the calculations in AGA Report No. 8 would be in compliance with this rule. Very-low-volume FMPs are grandfathered from the requirement to calculate supercompressibility under API 14.3; however these flow computers still have to calculate supercompressibility under NX-19. The BLM made no changes based on these comments.

Proposed § 3175.103(a)(2) would have required use of BLM-approved equations for devices other than a flange-tapped orifice plate. Because there are typically no API standards for these devices, the PMT would have to check the equations derived by the manufacturer to ensure they are consistent with the laboratory testing of these devices. For example, a manufacturer may use one equation to establish the discharge coefficient for a new type of meter that is being tested in the laboratory, while using another equation for the meter it supplies to operators in the field, potentially resulting in measurement bias or increased uncertainty. The BLM would have required that only the equation used during testing be used in the field.

The BLM received several comments stating that the BLM should use equations established by API and AGA rather than those provided by the PMT. Under the proposed rule, the BLM would have only approved a make and model of a meter if it was a differential type of meter other than a flange-tapped orifice plate. The flange-tapped orifice meter is the only differential type flow meter for which there is an AGA or API standard; there are no AGA or API standards for any other differential type flow meters requiring testing and review by the PMT. As a result, the PMT would have to verify and approve the flow equations proposed by the manufacturer based on the testing of that device. In the final rule, the BLM has added linear meters to the types of meters that the BLM could approve by make and model in § 3175.48. There are standards for many linear meters currently on the market, such as ultrasonic meters, Coriolis meters, and turbine meters. In light of the revised approval process for linear meters, the BLM added a provision to this paragraph to clarify that the flow rate equations recommended by the PMT and approved by the BLM would apply only if there are no industry standards for that device.

One commenter stated that the flow rate calculation method developed by the PMT should be effective within 6 months of approval by the BLM. The flow rate calculation method would be effective immediately after approval by the BLM. The BLM did not make any changes to the rule based on this comment.

§ 3175.103(b)

Section 3175.103(b) establishes a standard method for determining atmospheric pressure that is used to convert psig to psia. The BLM received one comment supporting the proposed requirement. The BLM made no changes based on this comment.

§ 3175.103(c)

Section 3175.103(c) requires that volumes and other variables used for verification be determined under API 21.1.4 and Annex B of API 21.1. The BLM did not receive any comments on this paragraph.

§ 3175.104 – Logs and records

§ 3175.104(a)

Section 3175.104(a) establishes minimum standards for the data that must be provided in a daily and hourly QTR. The data requirements are listed in API 21.1, Subsection 5.2. In the proposed version of § 3175.104(a), the BLM would have required that the QTR include the FMP number (by referencing § 3170.7), that certain data be reported to five significant digits, and that the data must be original, unaltered, unprocessed, and unedited. API 21.1, Subsection 5.2, recommends that the data be stored with enough resolution to allow recalculation within 50 parts per million, but it does not specify the number of significant digits required in the QTR. The BLM proposed to add this requirement because if too few significant digits are reported it is impossible for the BLM to recalculate the reported volume with sufficient accuracy to determine if it is correct or in error. The BLM believes that five significant digits are sufficient to recalculate the reported volumes to the necessary level of accuracy.

Section 3175.104(a) also requires that both daily and hourly QTRs submitted to the BLM must be original, unaltered, unprocessed, and unedited. It is common practice for operators to submit BLM-required QTRs using third-party software that compiles data from the flow computers and uses it to generate a standard report. However, the BLM has found in numerous cases that the data submitted from the third-party software is not the same as the data generated directly by the flow computer. In addition, the BLM consistently has problems verifying the volumes reported through reports generated by third-party software. Under proposed § 3175.104(a), the BLM would not have accepted reports generated by third-party software at all. This provision has been revised in the final rule to clarify that the BLM will accept data that was generated by third-party software, so long as that software is approved through the PMT process.

The BLM received several comments in response to these proposed requirements. Several commenters stated that many accounting systems are not capable of handling an 11-digit FMP number. The BLM agrees with these commenters and eliminated the requirement in § 3170.7(g) to store the FMP number in the accounting system. Instead, operators must use either an FMP number or the lease, unit PA, or CA number, along with a unique meter identification number, on their logs and records.

The BLM received several comments stating that reporting to five significant digits would be unworkable and recommending reporting to a specified number of decimal places. The BLM agrees with this comment and changed the final rule to require five decimal places for volume, flow time, extension, and three decimal places for average differential pressure, static pressure, and temperature.

The commenters also stated that the BLM should allow data to be collected and stored in third party software that meets the requirements of this section and has been reviewed by the PMT. One commenter stated that hand collection of data from each FMP would require significant additions in staffing. Another commenter suggested that approving third party software packages should be the role of the PMT. The BLM agrees with these comments and established a provision for the PMT to review accounting systems and recommend approval by the BLM it if it meets the requirements under § 3175.49.

§ 3175.104(b)

Section 3175.104(b) establishes minimum standards for the data that must be provided in the configuration log. The unedited data are similar to the existing requirements found in API 21.1. In addition, the BLM proposed to require:

- The FMP number, once established;
- The software/firmware identifiers that would allow the BLM to determine if the software or firmware version was approved by the BLM;
- For very-low-volume FMPs, the fixed temperature, if the temperature is not continuously measured, that would allow the BLM to recalculate volumes;
- The static-pressure tap location that would allow the BLM to recalculate volumes and verify the flow rate calculations done by the flow computer; and
- A snapshot report that would allow the BLM to verify the flow-rate calculation of the flow computer.

As described under § 3175.104(a), configuration logs generated by third-party software would not have been accepted. Based on the comments received under § 3175.104(a), the PMT will review and recommend approval of third-party software under § 3175.49.

In the final rule, the BLM adopted all of the proposed requirements listed above, with the exception of the FMP number requirement. The comments received by the BLM on § 3175.104(a), regarding the FMP number also apply to this section. As discussed above, the final rule does not require operators to place the FMP number in the configuration log.

The BLM received one comment stating that since the default location of the static-pressure tap is upstream per API 14.3.4.1, the static-pressure tap location should not have to be maintained in the configuration log unless it is located downstream. The BLM disagrees with the comment. It is not burdensome to identify the location of the static-pressure tap, and it will avoid confusion when performing audits.

§ 3175.104(c)

Section 3175.104(c) establishes minimum standards for the data that must be provided in the event log. This section requires that the event log retain all logged changes for the time period specified in proposed § 3170.7 (see 80 FR 40768 (July 13, 2015)). This provision will ensure that a complete meter history is maintained to allow verification of volumes. Proposed § 3175.104(c)(1) would have been a new requirement to record power outages in the event log. This is not currently required by API 21.1 or the statewide NTLs for EFCs.

The BLM received several comments in response to the proposed requirement in § 3175.104(c)(1) (final § 3175.104(c)) that the event log must record all power outages that inhibit the meter's ability to collect and store new data. The commenters stated that it is impossible to record a power off event with no power. Although the BLM believes that flow computer manufacturers could comply with this requirement by simply adding an additional clock, the BLM eliminated this requirement from the final rule because, apparently, flow computers do not currently have this capability.

§ 3175.104(d)

Section 3175.109(d) requires the operator to retain an alarm log following API 21.1, Subsection 5.6. The alarm log records events that could potentially affect measurement, such as over-ranging the transducers, low power, or the failure of a transducer. The BLM did not receive any comments on this section.

§ 3175.104(e)

Based on comments the BLM received on § 3175.104(a), the BLM added § 3175.104(e) to the final rule, which requires any accounting system used to submit QTRs, configuration logs, or even logs to the BLM, to be approved by the BLM based on a recommendation from the PMT. Please see § 3175.49 for further discussion.

§ 3175.110 – Gas sampling and analysis

This section sets standards for gas sampling and analysis at FMPs. Although there are industry standards for gas sampling and analysis, none of these standards are adopted in whole because the BLM believes that they would be difficult to enforce as written. However, some specific requirements within these standards are sufficiently enforceable and are adopted in this section. Heating value, which is determined from a gas sample, is as important to royalty determination as volume. Relative density, which is determined from the same gas sample, affects the calculation of volume. To ensure the gas heating value and relative density are properly determined and reported, the BLM developed requirements that address where a sample must be taken, how it must be taken, how the sample is analyzed, and how heating value is reported.

Table 1 to § 3175.110 contains a summary of requirements for gas sampling and analysis. The first column of Table 1 to § 3175.110 lists the subject of the standard. The second column contains a reference for the standard (by section number and paragraph) that applies to each subject area. The final four columns indicate the categories of FMPs for which the standard applies. The FMPs are categorized by the amount of flow they measure on a monthly basis. As in other tables, "VL" is very-low-volume FMP, "L" is low-volume FMP, "H" is high-volume FMP, and "VH" is very-high-volume FMP. Definitions of the various classifications are included in § 3175.10. An "x" in a column indicates that the standard listed applies to that category of FMP.

The BLM received numerous comments objecting to the proposed requirements in § 3175.110, suggesting that the BLM should use the API, AGA, and GPA gas sampling standards as written instead of developing new standards, or work with these organizations to develop new or revised standards if needed. The BLM incorporated the API and GPA sample standards to the extent possible. However, the BLM added clarification to the standards to ensure they are enforceable and to ensure that heating values are not under-reported by excluding liquids that may be flowing through the meter. Further explanation of these and other comments are discussed in the individual sections relating to gas sampling and analysis. The BLM did not make any changes to this section based on these comments.

One commenter stated that the cost of gas sampling and meter inspection frequencies would require them to increase staff by two-fold. However, the commenter did not offer any data to support this assertion. The BLM has accounted for this cost in the Economic and Threshold Analysis by accounting for the cost of taking a gas sample and performing a meter inspection. These costs include the labor costs of taking a sample which would also account for hiring additional staff if needed. The BLM did not make any changes to the rule based on this comment.

Another commenter stated that increased gas sampling frequency could negatively impact royalties from Coalbed Methane (CBM) production because the heating value of CBM tends to decline over time as the amount of carbon dioxide increases. Specifically, the presence of carbon dioxide in CBM gas decreases its heating value. As stated earlier, the goal of the rule is to improve measurement accuracy and verifiability, not to increase total royalty revenue. Therefore, it is the BLM's intent that the reported heating value needs to reflect, to the extent possible, the actual heating value of the gas being produced.

§ 3175.111 – General sampling requirements

§ 3175.111(a)

Section 3175.111(a) establishes the allowable methods of sampling. These sampling methods have been reviewed by the BLM and have been determined to be acceptable for heating value and relative density determination at FMPs. The BLM did not receive any comments on this paragraph.

§ 3175.111(b)

Proposed § 3175.111(b) would have set standards for heating requirements based on several industry references requiring the heating of all sampling components to at least

30°F above the HCDP. The purpose of the heating requirement is to prevent the condensation of heavier components, which could bias the heating value. This proposed section would have applied to all sampling systems, including spot sampling using a cylinder, spot sampling using a portable GC, composite sampling, and on-line GCs. Because most of the onshore FMPs will be downstream of a separator, the HCDP is defined in § 3175.10 as the flowing temperature of the gas at the FMP, unless otherwise approved by the AO. This would have required the heating of all components of the gas sampling system at locations where the ambient temperature is less than 30ºF above the flowing temperature at the time of sampling.

The BLM received numerous comments objecting to § 3175.111(b) in the proposed rule. Several commenters stated that the 30ºF requirement in API 14.1 was intended to prevent condensation and not to vaporize the gas being sampled. Other commenters stated that the 30ºF requirement applies when the HCDP is calculated and is not required if the HCDP is known. Because the BLM assumed the HCDP is the same as the flowing temperature of the gas in most cases, the commenters state that heating to 30ºF above flowing temperature is not required. One commenter suggested the BLM change the proposed rule to require operators to maintain the temperature of all gas sampling components at or above the flowing gas temperature. The BLM agrees with these comments and changed this paragraph to give operators the option of maintaining all sampling components at or above the flowing temperature of the gas or 30ºF above a calculated HCDP, whichever is less. The latter option would most likely apply to lean gases where the calculated HCDP is well below the flowing gas temperature.

One commenter stated that it is not necessary to assume the HCDP equals flowing temperature, and the HCDP can be calculated off of a previous sample. While the BLM agrees with this statement, nothing in the definition of HCDP would prevent an operator from proposing this method to the BLM for determining the HCDP at a particular FMP. The calculated HCDP would, however, be subject to the 30ºF heating requirement under the rule. The BLM did not make any changes to the rule based on this comment.

Another commenter stated that heating is not necessary for a dry gas. The BLM agrees that this may be true depending on the circumstances and what the commenter considers a "dry gas." If, for example, a dry (lean) gas has a calculated HCDP of 25ºF (and the AO approved the use of a calculated HCDP), and the sample was taken when the ambient temperature was 60°F, no heating would be required because the ambient temperature, and hence the temperature of the sampling equipment, would be greater than 30°F above the calculated HCDP. The BLM did not make any changes to the rule in response to this comment because the rule already accommodates this scenario.

One commenter stated that sampling without heating could bias the heating value to the high side. While the commenter did not elaborate on why they believe this is true, the BLM agrees that heating is necessary to obtain an accurate heating value. The BLM did not make any changes to the proposed rule based on this comment.

§ 3175.112 – Sampling probe and tubing

As specified in Table 1 to § 3175.110, very-low-volume FMPs are exempt from all requirements in § 3175.112 because, based on BLM experience with this level of production, a requirement to install or relocate a sample probe in very-low-volume FMPs could cause the well to be shut in.

§ 3175.112(a)

Section 3175.112(a) requires that all gas samples must be taken from a probe that complies with requirements of this section. The intent of the standard is to obtain a representative sample of the gas flowing through the meter. Samples taken from the wall of a pipe or a meter manifold are not representative of the gas flowing through the meter and could bias the heating value used in royalty determination. The BLM did not receive any comments on this paragraph.

§ 3175.112(b)

Proposed § 3175.112(b)(1) would have placed limits on how far away the sample probe can be from the primary device to ensure that the sample taken accurately represents the gas flowing through the meter. API 14.1 requires the sample probe to be at least five pipe diameters downstream of a major disturbance such as a primary device, but it does not specify a maximum distance. Under this proposal the operator would have had to place the sample probe between 1.0 and 2.0 times dimension "DL" (downstream length) downstream of the primary device. Dimension "DL" (API 14.3.2, Tables 7 and 8) ranges from 2.8 to 4.5 pipe diameters, depending on the Beta ratio. Therefore, the sample probe would have had to be placed between 2.8 and 9.0 pipe diameters downstream of the orifice plate, which is different than the requirement in API 14.1 noted above.

The sampling methods listed in API 14.1 and GPA 2166-05 will provide representative samples only if the gas is at or above the HCDP. It is likely that the gas at many FMPs is at or below the HCDP because many FMPs are immediately downstream of a separator. A separator necessarily operates at the HCDP, and any temperature reduction between the separator and the meter will cause liquids to form at the meter. To properly account for the total energy content of the hydrocarbons flowing through the meter, the sample must account for any liquids that are present. Gas immediately downstream of a primary device has a higher velocity, lower pressure, and a higher amount of turbulence than gas further away from the primary device. For the proposed rule, the BLM hypothesized that liquids present immediately downstream of the primary device are more likely to be disbursed into the gas stream than attached to the pipe walls. Therefore, a sample probe placed as close to the primary device as possible should have captured a more representative sample of the hydrocarbons – both liquid and gas – flowing through the meter than a sample probe placed further downstream of the meter. Any liquids captured by the sample probe would have been vaporized because of the heating requirements in proposed § 3175.111(b).

The BLM requested data supporting or contradicting any correlation between sample probe location and heating value or composition. The BLM also requested alternatives to this proposal, such as wet gas sampling techniques. The BLM did not receive any data or alternatives.

The BLM received numerous comments objecting to § 3175.112(b)(1) in the proposed rule. Many of the commenters stated that there is no technology currently available to extract entrained liquids to determine an accurate heating value, and that API 14.1 and GPA 2166 are only applicable to single-phase gas streams at or above the HCDP of the gas. Other commenters stated that the required sample probe location in the proposed rule is in direct conflict with API and GPA standards, and the BLM should just adopt those standards as written. Some comments stated that moving sample probes to comply with the proposed requirement would be cost prohibitive, could interfere with the pressure recovery downstream of the orifice plate, and would make it difficult to comply with both the sample probe placement requirements in API 14.1 as well as the proposed requirement. Several comments stated that low and very-low-volume FMPs should be exempt from the requirement. The BLM agrees with these comments and changed the final rule to adopt the sample probe placement requirements in API 14.1. However, the BLM retained the requirement that the sample probe be the first obstruction downstream of the primary device.

The BLM received one comment stating that the proper place to sample the gas is upstream of the orifice plate because liquids are less likely to fall out. Because the commenter did not provide any data to substantiate this claim, the BLM did not make any changes to the rule based on this comment.

Section 3175.112(b)(2) requires that the sample probe must be exposed to the same ambient temperature as the primary device. Locating the sample probe in the same ambient temperature as the primary device is not specifically addressed in API or GPA standards, but is intended to ensure that the gas sample contains the same constituents as the gas that flowed through the primary device. For example, if a primary device is located inside a heated meter house and the sample probe is outside the meter house, then condensation of heavier gas components could occur between the primary device and the sample point, thereby biasing the heating value and relative density of the gas.

The BLM received several comments objecting to the proposed requirement. The example provided for this requirement was specific to moving the sample probe into a heated meter house. The commenters believe it is impractical and cost prohibitive for the sample probe to be moved to a location where it is at the same ambient temperature as the primary device. The BLM agrees with this comment and added language to the final rule that allows the operator to comply with this standard by adding insulation or heat tracing along the entire meter run in lieu of moving the probe. Because it is difficult to define with any uniformity what level of insulation is needed to meet the intent of this requirement due to regional and local variations in operating conditions, the BLM did not establish specific requirements with respect to insulation in the final rule and, instead, added language which states that the AO may prescribe the quality of the insulation based on site specific factors such as ambient temperature, flowing temperature of the gas, composition of the gas, and location of the sample probe in relation to the orifice plate (i.e., inside or outside of a meter house). Note that the insulation option pertaining to the sample probe is identical to the insulation option pertaining to the thermometer well under § 3175.80(l)(2). Therefore, if an operator applied insulation to comply with the sample probe requirements in this section, they would also comply with the thermometer-well requirements under § 3175.80(l)(2) and vice versa.

One commenter stated that this requirement is not necessary because of the requirement in § 3175.111(b) to maintain the temperature of all sampling equipment at or above the flowing temperature of the gas. The BLM does not agree with this comment. While the heating requirement in § 3175.111(b) ensures that liquids will not form once the gas leaves the meter tube, it does nothing to ensure that the liquids do not form inside the meter tube. Any drop in temperature between the orifice plate and the sample probe could cause liquids to form. Because liquids tend to travel along the walls of the pipe, there is less chance that they would be collected in the sample even without a membrane filter installed in the sample probe. This increases the potential for liquids forming after the orifice plate to be unaccounted for. In practice, by complying with the requirement in § 3175.80(l), for thermometer wells to sense the same gas temperature that exists at the orifice plate, and with § 3175.112(b)(1) requiring the sample probe to be the first obstruction downstream of the orifice plate, operators would automatically comply with this requirement. In other words, if an operator insulated a meter run to comply with § 3175.80(l), the insulation would also cover the sample probe, which must be placed upstream of the thermometer well. The BLM did not make any changes to the rule as a result of this comment.

§ 3175.112(c)

Section 3175.112(c)(1) through (3) sets standards for the design and type of the sample probe, which are based on API 14.1 and GPA 2166. The sample probe ensures that the gas sample is representative of the gas flowing through the meter. The sample probe extracts the gas from the center of the flowing stream, where the velocity is the highest. Samples taken from or near the walls of the pipe tend to contain more liquids and are less representative of the gas flowing through the meter. The BLM did not receive any comments on these two paragraphs.

Proposed § 3175.112(c)(3) would have required that the collection end of the probe be placed in the center third of the pipe cross-section.

The BLM received a comment objecting to this requirement. The commenter believes this requirement is appropriate for pipe up to 6 inches in diameter; however, for any pipe diameter above 8 inches there is a risk of failure because of resonant vibration fatiguing the probe. The commenter recommended that the BLM use API 14.1, Subsection 7.4.1, Table 1, for sample probes used in 8-inch and greater runs. The BLM agrees with the comment and has changed the requirement by requiring the sample probe to be the shorter of the length needed to place the collection end of the probe in the middle third of the pipe cross-section or as stated in API 14.1, Table 1. In practice, nearly all FMPs will default to the first criterion because the vast majority of meter tubes at FMPs are between 2 and 4 inches in diameter.

Section 3175.112(c)(4) prohibits the use of membranes or other devices used in sample probes to filter out liquids that may be flowing through the FMP. Because a significant number of FMPs operate very near the HCDP, there is a high potential for small amounts of liquid to flow through the meter. These liquids will typically consist of the heavier hydrocarbon components that contain high heating values. The use of membranes or filters in the sampling probe could block these liquids from entering the sampling system and could result in heating values lower than the actual heating value of the fluids passing through the meter. This could result in a bias that would be in violation of § 3175.30(c).

The BLM received numerous comments objecting to the proposed requirement in § 3175.112(c)(4). Most of the commenters objected to the potential introduction of liquids into the gas sample which could significantly bias the heating value. The commenters stated that API 14.1 and GPA 2166 do not apply to multi-phase flow and there are currently no methods to accurately determine the heating value from multi-phase flow. Commenters also stated that prohibiting filters in the sample probe is contrary to API 14.1 and GPA 2166 and the BLM should adopt these standards as written.

The BLM disagrees with these comments and did not make any changes to this requirement as a result. The BLM recognizes that the sampling standards in API 14.1 and

GPA 2166 are only intended for single-phase gas streams and that prohibiting membrane filters could potentially bias the heating value if liquids are present. However, the commenters ignore the reality that liquids are often present at the FMP. The mere fact that sample probe filters are manufactured and used is an admission by the gas measurement community that liquids are present. If there were no liquids present, there would be no need for filters designed to keep liquids from entering the sampling system. By intentionally excluding liquids from the sample, the heating value derived from the sample will not represent the true value of the molecules flowing through the meter and will be biased to the low side, resulting in an underpayment of royalty. The BLM also disagrees with the implication by the commenters that filters are required to obtain an accurate heating value. The BLM does not understand how the commenters can deem a heating value to be accurate when the sampling system is designed to reject those components which have the greatest impact on the heating value. The BLM also believes that there are other, perhaps better ways to minimize the liquids at an FMP. For example, installing properly sized and functioning separators and insulating or heat tracing the meter run would help to avoid liquids. Unlike the membrane filter, these would minimize liquids at their source without biasing the heating value of a gas sample.

The BLM received several comments stating that the prohibition of filters in the sample probe conflicts with the requirement to clean GC filters in § 3175.113(d)(2) of the proposed rule, and that GC filters are necessary to protect the GC. The BLM believes that the commenters have misinterpreted this requirement. The BLM is not prohibiting filters at the inlet to GCs. The prohibition of filters in § 3175.112(c)(4) is specific to filters in the sampling probe. The BLM did not make any changes to the rule based on these comments.

§ 3175.112(d)

Section 3175.112(d) sets standards for the sample tubing that are based on API 14.1 and GPA 2166. To avoid reactions with potentially corrosive elements in the gas stream, the sample tubing can be made only from stainless steel or Nylon 11. Materials, such as carbon steel, can react with certain elements in the gas stream and alter the composition of the gas. The BLM did not receive any comments on this paragraph.

§ 3175.113 – Spot samples – general requirements

§ 3175.113(a)

Section 3175.113(a) provides an automatic extension of time for the next sample if the FMP is not flowing at the time the sample was due. Sampling a non-flowing meter would not provide any useful data. Under the proposed rule, a sample would have been required to be taken within 5 days of the date the FMP resumed flow.

The BLM received numerous comments objecting to the 5-day extension in § 3175.113(a). The commenters stated that 5 days is not sufficient time to determine whether a meter has resumed flow and to schedule a technician to go out to the site and collect a sample, especially for meters that flow intermittently or are in a remote location requiring extended travel time. Suggestions for increasing the timeframe ranged from 10 days to 1 month, although no specific rationale was given for these timeframes. The BLM agrees that 5 days may not be long enough and has changed the timeframe from 5 days to 15 days as a result. The BLM believes that 15 days should be adequate time to identify the resumption of flow and schedule a technician to travel to the site and collect a sample.

Most locations have telecommunications systems that allow the flow rate of a meter to be monitored remotely, and the resumption of flow could be detected almost immediately. For those locations that do not have telecommunications, personnel are typically onsite on a daily basis to monitor and inspect the equipment. The BLM rejected a 30-day timeframe because, especially for high- and very-high-volume FMPs, this could overlap with the due date of the next required sample. In addition to the comments suggesting specific timeframes, one commenter suggested requiring the sample be taken as soon as practical after flow resumes, while another commenter suggested the language specify that the meter has to resume continuous flow. The BLM did not make any changes as a result of these comments because the terms "as soon as practical" and "continuous flow" are not readily enforceable.

§ 3175.113(b)

Proposed § 3175.113(b) would have required the operator to notify the BLM at least 72 hours before gas sampling. A 72-hour notification period was proposed to allow sufficient time for the BLM to arrange schedules as necessary to be present when the sample is taken.

The BLM received many comments objecting to this proposed requirement. The majority of the commenters believe that 72-hour notification is unreasonable and burdensome. Several commenters suggested that the BLM should allow for the submission of monthly schedules which gives the BLM the ability to witness samples. The BLM agrees with these comments and included the option to submit monthly or quarterly sampling schedules to the BLM.

§ 3175.113(c)

Section 3175.113(c) establishes requirements for sample cylinders used in spot or composite sampling. Proposed § 3175.113(c)(1) and (2) would have adopted requirements for cylinder construction material and minimum capacity that are based on API and GPA standards.

The BLM received a few comments objecting to the proposed requirement in § 3175.113(c)(1). The commenters suggested that the BLM allow the use of aluminum cylinders because they are approved by the Department of Transportation for shipping samples and have been used without metal contamination issues. Some commenters indicated that the requirement in this paragraph to use stainless-steel cylinders would result in excessive cost to industry. Several commenters stated that the rule should allow their use in low-pressure applications. The BLM agrees with these comments and changed the rule to incorporate API 14.1, Subsection 9.1, regarding the allowable materials of construction, rather than requiring that sample cylinders be constructed of stainless steel. Under API 14.1, Subsection 9.1, sample cylinders can be made out of aluminum, but only if the aluminum is hard anodized.

Section 3175.113(c)(3) requires that sample cylinders be cleaned according to GPA standards. This section also requires operators to have documentation of the cylinder cleaning.

The BLM received a few comments either supporting or objecting to this proposed requirement. Several commenters supported the idea of cleaning the sample cylinders and maintaining a record of cleaning, which could include the use of a disposable tag indicating the cylinder was cleaned. Other commenters objected to both the need for cleaning sample cylinders and the need to keep a record of the cleaning. These commenters stated that this requirement is costly and burdensome with negligible benefit, and that a contaminated cylinder would be obvious (the commenter did not provide any information as to why that would be obvious). Another commenter believed cleaning and the associated documentation is the responsibility of the lab, not the operator. The BLM believes that clean sample cylinders are crucial in obtaining a representative sample of the gas, and that documentation of the cleaning is the only way BLM inspectors can ensure the cylinders are clean. Although the BLM did not change the rule based on these comments, we did change the wording of this requirement in the final rule to clarify that the operator must maintain this documentation onsite during sampling and make the documentation available to the BLM on request.

Proposed § 3175.113(c)(4) would have required clean sample cylinders to be sealed in a manner that prevents opening the sample cylinder without breaking the seal. It is important to be able to verify that sample cylinders are clean before sampling to avoid contaminating a sample. Therefore, the BLM sought comments on the practicality and cost of installing a physical seal on the sample cylinder as proposed in § 3175.113(c)(4), or on other methods that the BLM could use to verify that the cylinders are clean. The BLM did not receive any suggestions as to how a sample cylinder could be sealed. The BLM is not aware of any industry standard or common industry practice that requires a seal to be used.

The BLM received several comments objecting to the proposed requirement in § 3175.113(c)(4). Most commenters stated that sealing the cylinders is not an industry practice and will result in extra expense that will have minimal gain. Several commenters stated that there is no way to seal a cylinder while other commenters stated that it was unclear in the proposed rule when the cylinder would have to be sealed (before or after the sample was taken) and what type of seal would be acceptable to the BLM. The BLM agrees with the comments stating there is no cost-effective method to seal sample cylinders and deleted this requirement in the final rule. The BLM believes that the documentation required in § 3175.113(c)(3) will ensure that sample cylinder cleaning is taking place to the best extent possible.

§ 3175.113(d)

Section 3175.113(d) sets standards for spot sampling using a portable GC. This section primarily addresses the sampling aspects; the analysis requirements are prescribed in § 3175.118. Both the GPA and API recognize that the use of sampling separators, while sometimes necessary for ensuring that liquids do not enter the GC, can also cause significant bias in heating value if not used properly. Section 3175.113(d)(1) adopts GPA standards for the material of construction, heating, cleaning, and operation of sampling separators. It also requires documentation that the sample separator was cleaned as required under GPA 2166-05 Appendix A.

The BLM received several comments objecting to this requirement. One commenter cautioned against the use of separators because of the potential for liquids to condense in the cylinder and get into the GC. Another commenter stated that this requirement is impractical to do prior to taking each sample because the cleaning equipment cannot be carried to the field. The commenter suggested the BLM only require sample separator cleaning on a periodic basis. The BLM considered prohibiting the use of sample cylinders altogether because API 14.1, Subsection 8.7, cautions against their use. However, the BLM also believes that if used properly they can protect the GC while not contaminating the sample. In order to ensure that the sample separator does not contaminate a sample, the BLM believes it is essential to require the separator to meet the same standards as a sample cylinder regarding cleaning. The BLM disagrees with the comments suggesting only periodic cleaning and did not make any changes to the rule based on these comments. The BLM did add language to the final rule clarifying that the same documentation and availability of the documentation required for sample cylinders is required for separators.

Proposed § 3175.113(d)(2) would have required the filter at the inlet to the GC to be cleaned or replaced before taking a sample. Industry standards do not provide specific requirements for how often the filter should be cleaned or replaced; however, a contaminated filter could bias the heating value.

The BLM received numerous comments objecting to the proposed requirement in § 3175.113(d)(2). Most of the commenters stated that cleaning the GC filter prior to each sample is expensive and impractical because it would require the operator to carry cleaning agents to the field which are difficult to transport. Several commenters stated that the filter should only be cleaned or replaced as necessary or when the operator suspects the filter is contaminated. The BLM agrees with these comments and deleted this requirement as a result. While the BLM believes that a contaminated filter could cause an errant analysis, there is no way to inspect or enforce a requirement for periodic or "as needed" cleaning or replacement frequency.

Several commenters expressed concern over the removal of the filter at the inlet to the GC because liquids, such as glycol and compressor oil, could damage the GC. The BLM did not make any changes to the rule based on this comment because nowhere has the BLM proposed removing the filter at the inlet of the GC.

Section 3175.113(d)(2) (§ 3175.113(d)(3) in proposed rule) requires the sample line and the sample port to be purged before sealing the connection between them. This requirement was derived from GPA 2166-05, which requires a similar purge when sample cylinders are being used. The purpose of this requirement is to disperse any contaminants that may have collected in the sample port and to purge any air that may otherwise enter the sample line.

The BLM received a few comments on this section. While the commenters did not object to this requirement, they suggested that the BLM reword the requirement to clarify that the purging must be done with the gas being sampled, not with air. One commenter recommended that the BLM change the phrase "before sealing the connection" to "before completing the connection." The BLM agrees with these comments and made the requested wording changes in the final rule.

Section § 3175.113(d)(3) (§ 3175.113(d)(4) in the proposed rule) would have required portable GCs to adhere to the same minimum standards as laboratory GCs under proposed § 3175.118. The requirements of proposed § 3175.118 would have included provisions regarding the design, operation, verification, and calibration of GCs, the number of consecutive samples that must be run, the verification frequency, when a calibration had to be done, standards for calibration gas, and the GC calibration report.

The BLM received one comment requesting clarification of § 3175.113(d)(3) (§ 3175.113(d)(4) in proposed rule). The commenter stated that the requirement for a GC to be "designed" in accordance with GPA 2261-13 (GPA 2261-00 was referenced in the proposed rule) does not provide sufficient flexibility for the development of new technology and processes. The BLM agrees with this comment and reworded the requirement in the final rule to read: "The portable GC must be operated, verified, and calibrated…" instead of "The portable GC must be designed, operated, and calibrated…." The BLM believes that removing the word "designed" will help provide flexibility for new technology and adding the word "verified" will help ensure that both the verification and calibration of a GC is done under § 3175.118.

The BLM added § 3175.113(d)(4) to the final rule in response to changes made to § 3175.118(c)(1). In the proposed rule, this section would have required portable GCs to be verified not more than 24 hours before sampling at an FMP. This proposed requirement would have facilitated the BLM's ability to ensure that the portable GC was verified properly prior to sampling. In response to comments arguing against the practicality of verifying a portable GC every 24 hours, the BLM eliminated this requirement in the final rule. However, the BLM believes that in order to ensure portable GCs have been verified in accordance with the provisions of § 3175.118, the operator must have the documentation of the verification onsite and available to the BLM when using a portable GC.

Proposed § 3175.113(d)(5) would have prohibited the use of portable GCs if the flowing pressure at the sample port was less than 15 psig, which can affect accuracy of the device. This proposed requirement was based on GPA 2166-05.

The BLM received a few comments objecting to proposed § 3175.113(d)(5). The commenters stated that GCs can sample with pressures down to 5 psig because of newer technology and the use of vacuum pumps to help step up the pressure in accordance with

API 14.1, Subsection 11.10. One commenter suggested the BLM not allow portable GCs to take samples below 15 psig unless the GC is approved by the PMT to handle pressures below 15 psig. Based on these comments, the BLM removed this requirement in the final rule. The BLM believes that setting a minimum pressure for portable GCs would tie the regulation to existing technology. The BLM generally agrees with the comment that review and approval of new GC technology could be a role for the PMT.

The BLM also added § 3175.113(d)(5) and (6) to the final rule in response to changes made to § 3175.118(b). Under the proposed rule, § 3175.118(b) would have required that for both portable and laboratory GCs, samples would have to be analyzed until three consecutive samples were within the repeatability standards of GPA 2261-00, Section 9. Based on comments received on this section, this requirement was eliminated in the final rule. Please see the discussion on § 3175.118(b). Portable GCs are subject to a less controlled environment than are laboratory GCs and also analyze a live gas stream with varying composition. Laboratory GCs analyze fixed-composition samples stored in sample cylinders. For these reasons the BLM believes that additional quality control standards are needed for portable GCs to ensure the gas sampling and analyses are accurate. Section 3175.113(d)(5) establishes the minimum number of samples that must be taken and analyzed. For very-low- and low-volume FMPs, a minimum of three samples and analyses are required. For high- and very-high-volume FMPs, the final rule establishes tolerances between the highest and lowest heating values for three consecutive samples. The basis for the tolerances is explained under the discussion for § 3175.118(b). The BLM believes that three samples provide a reasonable balance between cost and statistical representation of the gas being sampled.

Section 3175.113(d)(6) sets standards on how the heating value and relative density from the samples and analyses taken under § 3175.113(d)(5) are determined. One method that is explicitly allowed in the final rule is to calculate the heating value and relative density by taking the average of the heating values and relative densities determined from the three samples taken. The other method explicitly allowed by the rule is to use the median heating value and relative density from the three samples taken. The BLM also added a provision where the BLM can approve additional methods.

§ 3175.114 – Spot samples – allowable methods

Section 3175.114 adopts three spot sampling methods using a cylinder and one method using a portable GC. The three allowable methods using a cylinder were selected for their ability to accurately obtain a representative gas sample at or near the HCDP, the relative effectiveness of the method, and the ease of obtaining the sample. Because the BLM determined that the procedures required by either GPA or API standards were clear and enforceable as written, the BLM adopted them verbatim.

The most common method currently in use at FMPs is the "purging – fill and empty" method, which is one of the methods that is allowed in the rule (§ 3175.114(a)(1)); therefore, it is not expected that this requirement will result in any significant changes to current industry practice. Section 3175.114(a)(2) also allows the helium "pop" method and § 3175.114(a)(3) allows the "floating piston cylinder" method. The fourth spot sampling method (§ 3175.114(a)(4)) is the use of a portable GC, which is discussed in § 3175.113(d). Section 3175.114(a)(5) provides that the BLM would post other approved methods on its website once they are reviewed by the PMT and approved by the BLM.

Section 3175.114(b) allows the use of a vacuum gathering system when the operator uses a "purging – fill and empty" method or a helium "pop" method and when the flowing pressure is less than or equal to 15 psig. Of the four spot sampling methods allowed in this section, API 14.1, Subsection 11.10, recommends that only the "purging – fill and empty" method and the helium "pop" method be used in conjunction with the vacuum gathering system. As a result, the "floating piston cylinder" method is not allowed in conjunction with a vacuum gathering system. Based on comments on § 3175.113(d)(5), the BLM removed the prohibition for using portable GCs when the pressure is less than 15 psig.

Several comments objected to the BLM's piecemeal adoption of API 14.1 and GPA 2166 and stated that the BLM should have incorporated both documents in whole, including all of the sampling methods referred to in Appendix F of API 14.1. One commenter also objected to the BLM's incorporating these standards and then using the standards to sample gas containing liquids. The commenter stated that both of these standards are only intended for single phase gas sampling and should not be applied when liquids are present. The BLM did not make any changes as a result of these comments. The issue of sampling with liquids present is discussed under § 3175.112. The BLM is only enforcing specific parts of API 14.1 and GPA 2166 because these parts are directly relevant to the BLM's goal of ensuring that samples are properly taken and are clear and enforceable as written.

The BLM selected the sampling methods described in this section because data show they work well at the HCDP under the controlled temperature conditions, and both the "purging – fill and empty" and helium "pop" methods are repeatable, as documented in the July 2004 study, Evaluation of a Proposed Gas Sampling Method Performance Verification Test Protocol, conducted by Southwest Research Institute for the United States Minerals Management Service. The methods indicated in this subpart were chosen for a combination of ease of use and accurate determination of the composition and heating value in field situations. The BLM found: (1) The evacuated cylinder method is prone to leaky valves or operator error that could introduce air into the evacuated cylinder; (2) The reduced-pressure method can cause condensation of heavy components with re-vaporization prior to sampling because this process is below the pressure of the pipeline, leading to cooling from the expansion of the gas; (3) With the water displacement method, water can absorb carbon dioxide, hydrogen sulfide, and other components which will affect the water vapor content of the sample; (4) Similar issues were found utilizing the glycol displacement method; and (5) The purged-controlled rate method encouraged the possibility of liquids condensing due to the pressure reduction as the purging is performed.

§ 3175.115 – Spot samples – frequency

§ 3175.115(a)

Section 3175.115(a) requires that gas samples be taken at least every 6 months at low-volume FMPs and at least annually at very-low-volume FMPs. The BLM determined that annual sampling has the potential for biasing the heating value. If, for example, an annual sample is always taken in January when the ambient temperature is low, there could be a higher possibility that the heavier components could liquefy and bias the composition. This would not be consistent with § 3175.31(c), which requires the absence of significant bias in low-volume FMPs. The BLM believes that sampling at low-volume FMPs at least every 6 months will reduce the potential for bias.

Section 3175.115(a) will require spot samples at high- and very-high-volume FMPs to be taken at least every 3 months and every month, respectively, unless the BLM determines that more frequent analysis is required under § 3175.115(b). The sampling frequencies presented in Table 1 to § 3175.110 were developed as part of the "BLM Gas Variability Study Final Report," May 21, 2010. The study used 1,895 gas analyses from 217 points of royalty settlement and concluded that heating value variability is not a function of reservoir type, production type, age, richness of the gas, flowing temperature, flow rate, or other factors that were included in the study. Instead, the study found that heating value variability appears to be unique to each meter. The BLM believes that the lack of correlation with at least some of the factors identified here could be a symptom of poor sampling practices in the field. The study also concluded that heating-value uncertainty over a period of time is manifested by the variability of the heating value, and more frequent sampling would lessen the uncertainty of an average annual heating value, regardless of whether the variability is due to actual changes in gas composition or to poor sampling practices. The frequencies shown in Table 1 to § 3175.110 for high- and very-high-volume FMPs are typical of the sampling frequency required to obtain the heating value certainty levels that are required in § 3175.31(b)(1) and (2).

The BLM received several comments on the proposed sampling frequencies in Table 1 to § 3175.110 of the proposed rule. One commenter did not believe the proposed sampling frequencies occurred often enough and proposed a frequency of once every 6 months for very-low-volume and low-volume FMPs, and once per month for high- and very-high-volume FMPs. The commenter did not submit any data or rationale for the proposed frequencies. Another commenter suggested that increased sampling is not needed for “dry” gas wells, although no definition of what constitutes a “dry” gas well was given by commenter, nor did the commenter provide any data to support that a lower frequency for these FMPs is justified. Another commenter stated that the frequencies are too high in general and do not account for driving time. Again, the commenter did not submit any data justifying this comment. The BLM did not make any changes to the proposed rule based on these comments because the BLM believes the frequencies are reasonable as written in the proposed rule and no data were provided to justify a different frequency.

One commenter stated that it is a violation of existing contracts to change required sampling frequencies. The BLM did not make any changes to the rule based on this comment because all existing Federal oil and gas leases require compliance with the applicable Federal regulations, even if those regulations are stricter than the provisions of a gas sales contract attached to any particular lease.

One commenter expressed a concern that the BLM was intending to assign a Btu value to a particular zone. The BLM has no intention of assigning Btu values to particular zones. If that were the intent, the BLM would have required that in the proposed rule instead of proposing provisions to ensure the accuracy and verifiability of heating values measured at each FMP. No changes to the rule were made as a result of this comment.

§ 3175.115(b)

Section 3175.115(b) will allow the BLM to require a different sampling frequency if analysis of the historic heating value variability at a given FMP results in an uncertainty that exceeds what is required in § 3175.31(b)(1) and (2). Under § 3175.115(b), the BLM can increase or decrease the required sampling frequency given in Table 1 to § 3175.110. To implement this requirement, the BLM is developing a database called GARVS. This database will be used to collect gas sampling and analysis information from Federal and Indian oil and gas operators. GARVS will analyze those data to implement other gas sampling requirements as well. The sample frequency calculation in GARVS will be based on the heating values entered into the system under § 3175.120(f).

Several comments asserted that the method of calculating a sampling frequency was not provided in the proposed rule. While the BLM did not propose a calculation method in the proposed rule, a calculation method was included in the BLM Gas Variability Study that was included with the documentation on the proposed rule. The BLM did not make any changes as a result of these comments.

Many commenters stated that the sampling frequency should be based on volume, not variability. The BLM disagrees. While there is some economic rationale for sampling less frequently at lower-volume meters, any volume-based sampling frequency is arbitrary and ignores statistical methods. As stated by other commenters, the uncertainty of any given heating value is only a function of the analytic procedures used to obtain and analyze the sample. To clarify the comment, if, for example, a particular sampling and analysis method provides a heating value uncertainty of ±2 percent, more frequent sampling would not eliminate that uncertainty. In other words, if an operator took one sample per year and was confident that the process was done properly and the heating value derived from that sample was ±2 percent, there would be no benefit to sampling any more frequently. The reason for more frequent sampling is not related to the uncertainty of each sample; rather, it is related to the uncertainty of deriving heating values over a period of time from snapshots of heating values taken during that time period. If, for example, the heating value at a particular meter were always the same, there would be no reason to take spot samples from this meter regardless of how much volume it measured. On the other hand, if the heating value at a particular meter were known to vary greatly from sample to sample, the heating value from one sample could misrepresent the average heating value of the gas flowing through the meter and result in significant underpayment or overpayment of royalty. The solution would be to take more samples of the highly fluctuating meter to obtain a better representation of the true heating value over time. The difference in sampling frequency between the first example and the second example is not related to the volume measured; rather, it is related to the degree of heating value variability at that meter. The cause of the high degree of fluctuation in the second example – whether it be actual changes in the gas composition, poor sampling practice, or environmental conditions during sampling – is largely irrelevant. Volume has bearing on sampling frequency only in that sampling entails a cost and at lower-volume meters, the cost of more frequent sampling due to high variability is simply not worth the potential loss or gain in revenue resulting from less frequent sampling. The BLM incorporated statistically based sampling frequencies for high- and very-high-volume FMPs where economics is not as important a consideration and volume-based sampling frequencies for lower-volume FMPs where economics is a consideration. The BLM did not make any changes to the proposed rule as a result of these comments.

One commenter stated that based on their experience performing gas analyses, fluctuations in heating value are typically due to changes in pressure, temperature, or down-hole equipment and have nothing to do with volume. The BLM Gas Variability Study did not find any correlation between heating value variability and pressure, temperature, or down-hole equipment. The BLM did not make any changes to the rule because no changes were requested by the commenter.

One commenter wondered if the BLM is requiring increased sampling frequency because it believes that operators use poor sampling practices. The BLM has no data to conclude that poor sampling practices are the cause of high heating value variability. However, there are only two potential causes of high variability: The actual composition of the gas is changing significantly over time or the operator is using poor sampling practices. Regardless of the cause, the only way to achieve a set level of average annual heating value uncertainty is to change the sampling frequency to achieve the required level of uncertainty. As explained elsewhere in this preamble, the sampling frequency can change (become more or less frequent) depending on what the data shows for a particular facility over time. The BLM did not make any changes to the rule based on this comment.

The BLM received numerous comments stating that uncertainty and variability are two unrelated concepts, and the BLM should not use variability as a trigger for increased sampling frequency. The BLM agrees that variability should not be the trigger. That is why the BLM is using average annual heating value uncertainty as the trigger. The relationship between variability and average annual heating value uncertainty is explained in the discussion of § 3175.31(b). The BLM did not make any changes to the rule based on this comment.

Several comments suggested that the BLM provide industry with the sampling frequency algorithm. The BLM agrees with this comment and has provided the algorithm in the final rule. It is the same algorithm provided in the BLM Gas Variability Study, which was posted at www.regulations.gov with the proposed rule.

Several commenters suggested that the BLM should work with industry to develop sampling schedules or conduct further study before implementing this requirement. While the BLM does not believe further study is needed to support this method, the rule allows the BLM to approve other methods that achieve the same goal (see § 3175.31(a)(4)). These other methods could be developed jointly with industry.

One commenter stated that they were in favor of the requirement to allow sampling frequency adjustment. The BLM did not make any changes to the rule based on this comment, as no changes were requested by the commenter.

One commenter stated that changing the required sampling frequencies for high- and very-high-volume FMPs when there is a change in the variability of previous heating values would create uncertainty for operators of these FMPs, posing an excessive burden on industry. Based on this and other comments, the BLM added a provision in the final rule (§ 3175.115(b)(1)) that would prohibit the BLM from changing the sampling frequency for a high-volume FMP for 2 years after the FMP starts measuring gas (or 4 years from the effective date of the rule, whichever is later). For very-high volume FMPs, the BLM could not change the sampling frequency for 1 year after the FMP starts measuring gas (or 3 years from the effective date of the rule, whichever is later). Based on the initial 3-month sampling frequency required for high-volume FMPs in Table 1 to § 3175.110, this would result in the collection, analysis, and reporting of at least eight samples before the BLM could change the sampling frequency. For very-high-volume FMPs, the monthly sampling required in Table 1 to § 3175.110 would yield at least 12 samples. Assuming the operator is tracking the variability of these samples using the equation given under the definition of heating value variability (see § 3175.10(a)), the operator will have ample indication that an FMP has a variability that is high enough to warrant an increased sampling frequency. The operator would also have the opportunity to address the high variability by implementing additional training or quality-control measures in the sampling and analysis of that FMP.

Section 3175.115(b)(3) clarifies that the new sampling frequency would remain in effect until a different sampling frequency is justified by an increase or decrease of the variability of previous heating values. In proposed § 3175.115(b)(3) (§ 3175.115(b)(4) in the final rule), GARVS would have rounded down the calculated sampling frequency to one of seven possible values: Every week, every 2 weeks, every month, every 2 months, every 3 months, every 6 months, or every 12 months. The BLM would notify the operator of the new required sampling frequency. Several comments stated that the increased sampling frequency would be difficult logistically, especially if it is once per week as in the proposed rule. Because the BLM agrees that weekly sampling is probably not practical in many situations, the BLM eliminated the requirement for weekly sampling in the final rule. A 2-week sampling frequency is the maximum sampling frequency that the BLM will require under § 3175.115(b)(4) of the final rule. In addition, the BLM eliminated the entry in Table 1 to § 3175.115 that corresponded to weekly sampling.

One commenter stated that the cost of performing additional gas sampling and entering the gas analyses into GARVS would be prohibitive, although the commenter did not submit any data to substantiate this claim. The BLM does not believe that the new gas sampling requirements are cost prohibitive. Under the new volume thresholds, very-low-volume meters, for which no increase in gas sampling frequency is required as compared to Order 5, constitute 51 percent of all FMPs. The rule only requires one additional sample per year at low-volume FMPs. The estimated cost increase for low-volume FMPs, which constitute 38 percent of all FMPs, is $100 per year per FMP. The rule only requires higher sampling frequencies at FMPs flowing more than 200 Mcf/day, which only constitute 11 percent of FMPs. The BLM's analysis indicates that even at a maximum sampling frequency of once every 2 weeks, the requirement is not cost prohibitive. The BLM does not anticipate a significant cost of entering the gas analyses into GARVS because GARVS will allow a direct download of gas analysis data from approved third-party software packages that most operators already use. The BLM did not make any changes to the rule as a result of this comment.

Proposed § 3175.115(b)(4) (§ 3175.115(b)(5) in the final rule) would have required the operator to install a composite sampling system or an on-line GC if sampling every week would still not be sufficient to achieve the certainty levels that would be required under § 3175.31(b)(1) or (2).

The BLM received several comments stating that composite samplers and on-line GCs are only cost-effective on high-volume meters. One commenter stated that composite samplers are not cost-effective unless the flow rate is over 5,000 Mcf/day and on-line GCs are not cost-effective unless the flow rate is over 15,000 Mcf/day. Another commenter stated that composite samplers and on-line GCs are not cost-effective on high-volume FMPs (as defined in the proposed rule) and the “low end” of the very-high-volume threshold. Installed cost estimates for on-line GCs given by commenters ranged from $45,000 to $110,000. The BLM generally agrees with these comments and eliminated the requirement in the proposed rule for high-volume FMPs to use composite samplers or on-line GCs if operators could not achieve an average annual heating value uncertainty of ±2 percent through spot sampling. The BLM believes that the use of composite samplers would not be cost prohibitive at very-high-volume FMPs. Although the BLM did not receive any cost estimates for composite sampling systems in the comments, research shows that a heated composite sampling system costs about $8,000 and using a 2.5 multiplier for the installed cost, as recommended by several commenters, results in an installed cost of about $20,000. A $20,000 cost would have a payout of less than 10 days at a flow rate of 1,000 Mcf/day.

One commenter expressed the opinion that the BLM is trying to force the use of composite sampling systems or on-line GCs at every FMP. Neither the proposed rule nor the final rule would force every FMP to have a composite sampling system or on-line GCs. Although the BLM did not make any changes to the rule based on this comment, the BLM is aware that these devices are expensive and removed the proposed requirement for composite sampling systems or on-line GCs at high-volume FMPs. The BLM estimates that as a result, only 900 FMPs nationwide will fall into the very-high-volume category. From the BLM Gas Variability Study, approximately 25 percent of all FMPs included in the study would not be able to meet a 1 percent average annual heating value uncertainty with a 2-week sampling frequency, the maximum spot sampling frequency required in the rule. Some of the data in the study also suggest that variability tends to be less for higher flow rate meters, although the sample size was too small to reach any definite conclusion. Therefore, the BLM estimates that composite sampling systems or on-line GCs would only be required on a maximum of 225 FMPs, or 0.3 percent of all FMPs nationwide.

One commenter stated that composite samplers and on-line GCs may not perform well with two-phase flow and would have no demonstrated benefit. The BLM does not believe that FMPs flowing at 1,000 Mcf/day or greater will have significant issues with two-phase flow. Generally, two-phase flow occurs at lower-volume meters where it is difficult to obtain adequate separation and control temperature drop between the separator and meter. The commenter did not provide any data to substantiate their argument that two-phase flow would be an issue with higher-volume FMPs. The BLM also disagrees that a composite sampler would have no benefit. A properly designed and operating composite sampling system will result in a heating value that is truly integrated over time, thereby eliminating the uncertainty caused by basing heating value over a time period on heating value “snapshots” in time. The BLM did not make any changes as a result of this comment.

One commenter stated that composite samplers or on-line GCs may still have more than ±2 percent uncertainty. The commenter did not provide any data to substantiate this claim, however. As stated earlier, the performance requirement in § 3175.31(b) relates to average annual heating value uncertainty, not to the uncertainty of a single sample or analysis. To address this comment, the BLM added language to § 3175.115(b)(5) that states, “Composite sampling systems or on-line gas chromatographs that are installed and operated in accordance with this section comply with the uncertainty requirement of § 3175.31(b)(2).” This should eliminate any confusion with this requirement.

§ 3175.115(c)

Section 3175.115(c) establishes the maximum allowable time between samples for the range of sampling frequencies that the BLM would require, as shown in Table 1 to § 3175.115. This allows some flexibility for situations where the operator is not able to access the location on the day the sample was due, although the total number of samples required every year would not change. For example, if the required sampling frequency was once per month, the operator would have to obtain 12 samples per year. If the operator took a sample on January 1st, the operator would have until February 14th to take the next sample (45 days later). In the final rule, the BLM adjusted Table 1 to § 3175.115 by eliminating the weekly sampling entry to correspond to the changes made in § 3175.115(b)(4).

§ 3175.115(d)

If a composite sampling system or on-line GC is required by the BLM under § 3175.115(b)(5) or opted for by the operator, § 3175.115(d) requires that device to be installed and operational within 30 days after the due date of the next sample. For example, if the required sampling frequency is every 2 weeks and the next sample is due on April 18th, the composite sampling system or on-line GC must be operational by May 18th. The operator is not required to take spot samples within this 30-day time period. The BLM considers both composite sampling and the use of on-line GCs to be superior to spot sampling, as long as they are installed and operated under the requirements in proposed §§ 3175.116 and 3175.117, respectively.

Numerous comments argued that the 30-day timeframe to install a composite sampling system or on-line GC under § 3175.115(d) is too short to account for the time to design, order, and install the system. The comments suggested timeframes ranging from 3 months for composite sampling systems to 6 months for both composite sampling systems and on-line GCs. The BLM disagrees with these comments because the BLM added a provision under § 3175.115(b) that will delay the requirement to install a composite sampling system or on-line GC at very-high-volume FMPs until 1 year of gas analysis data are gathered. For very-high-volume FMPs, this will result in a minimum of 12 samples based on the initial monthly sampling frequency required in Table 1 to § 3175.110.

The BLM believes that an operator of a very-high-volume FMP should have ample indication after 6 months of production (i.e., six samples) whether the FMP will have a high enough heating value variability that a composite sampling system or on-line GC will likely be required. If the operator begins the process of ordering a composite sampling system or on-line GC after 6 months, it would be ready to go within the 30-day timeframe of when the BLM requires it to be installed as required in § 3175.115(d). The BLM did not make any changes as a result of these comments. However, the BLM made two other revisions based on other comments that should result in many fewer composite samplers or on-line GCs being required as compared to the proposed rule. First, given the high production-decline rate of many wells on Federal and Indian leases, the 1-year delay will most likely be enough time for many FMPs that were originally categorized as very-high-volume to drop to lower-volume categories that are not subject to the requirement to install on-line GCs or composite sampling systems. Second, for FMPs that measure gas from newly drilled wells, the BLM will no longer include any production from that well prior to the second full month of its production, when determining the flow rate category for an FMP (see the definition of “averaging period” in 43 CFR 3170.3). As a result, with these changes, it is likely that many FMPs that would have been initially categorized as very-high-volume in the proposed rule will no longer meet the very-high-volume threshold in the final rule.

§ 3175.115(e)

Section 3175.115(e) addresses FMPs where a composite sampling system or on-line GC was removed from service. In these situations, the spot sampling frequency for that meter reverts to the requirement under § 3175.115(a) and (b). The BLM did not receive any comments on this section.

§ 3175.116 – Composite sampling methods

Section 3175.116 sets standards for composite sampling. The BLM used API 14.1, Subsection 13.1, as the basis for § 3175.116(a) through (c). Section 3175.116(d) requires the composite sampling system to meet the heating-value uncertainty requirements of § 3175.31(b).

Although the BLM did not receive any comments on this section, we removed proposed paragraph (d) , which would have required the composite sampling system to meet the heating value uncertainty requirements of § 3175.31(b). Based on comments received on § 3175.115, the BLM added a statement to § 3175.115(b)(5) declaring that composite sampling systems and on-line GCs comply with the heating value uncertainty requirements of § 3175.31(b). Therefore, paragraph (d) is no longer necessary.

§ 3175.117 – On-line gas chromatographs

Section 3175.117 sets standards for on-line GCs. Because there are few industry standards for these devices, the BLM was particularly interested in comments on the proposed requirements or whether different or alternative standards should be adopted

The BLM received one comment that questioned the use of GPA 2261 for extended analysis relating to on-line GCs. The BLM agrees with the comment and has incorporated by reference GPA 2286-14, which relates to the procedures for obtaining an extended analysis. Because extended analyses apply to more than just on-line GCs, this standard is referenced under § 3175.118(e) (discussed below).

The BLM also removed proposed paragraph (b) from this section, which would have required the on-line GC to meet the heating value uncertainty requirements of § 3175.31(b). Based on comments received on § 3175.115, the BLM added a statement to § 3175.115(b)(5) declaring that composite sampling systems and on-line GCs comply with the heating value uncertainty requirements of § 3175.31(b). Therefore, paragraph (b) of this section is no longer necessary. As a result of this change, paragraph (d) of this section was moved to paragraph (b).

§ 3175.118 – Gas chromatograph requirements

This section establishes requirements for the analysis of gas samples.

§ 3175.118(a)

Under proposed § 3175.118(a), these minimum standards would have applied to all GCs, including portable, on-line, and stationary laboratory GCs. These requirements were derived primarily from two industry standards: GPA 2261-00 and GPA 2198-03. The BLM received several comments that GPA 2261-00 has been updated with GPA 2261-13, and that the BLM should be incorporating the most recent version of this standard.

The BLM agrees with these comments and incorporates GPA 2261-13 into the final rule. The BLM also deleted the word “designed” from the requirement because GC technology may progress faster than the GPA standards can be updated and requiring GCs to be designed to a specific GPA standard could impede the acceptance of new technology.

§ 3175.118(b)

Proposed § 3175.118(b) would have required that gas samples be run until three consecutive runs met the repeatability standards stated in GPA 2261-00. Obtaining three consistent analysis results would have ensured that any contaminants in the GC system have been purged and that system repeatability is achieved. This proposed section would have also required that the sum of the un-normalized mole percentages of the gas components detected are between 99 percent and 101 percent to ensure proper functioning of the GC system. This requirement was based on GPA 2261-00. The mole percentage is the percent of a particular molecule in a gas sample. For example, if there were 2 propane molecules for every 100 molecules in a gas sample, the mole percentage of propane would be 2. If the GC were perfectly accurate (zero uncertainty), the sum of mole percentages would always add up to 100. However, due to the uncertainties in the calibration and operation of the GC, the sum of the mole percentages varies from 100 percent. The amount of variation is an indication of how well the GC is performing and is a tool for quality control.

The BLM received numerous comments objecting to the proposed requirement to run analyses until the sum of the un-normalized mole percentage is between 99 percent and 101 percent. The commenters stated that this is only applicable when verifying the GC and not for the actual analysis. The comments stated that this is often unachievable for portable GCs because of changes in atmospheric pressure during the analysis, especially when the inlet pressure to the GC is less than 30 psig. Suggestions included a range of 97 to 103 mole percent and 98 to 102 mole percent. The BLM agrees with these comments and changed the rule to read “97 to 103” mole percent. This would apply to both portable GCs and laboratory GCs.

The BLM received numerous comments objecting to the proposed requirement to perform analyses until three consecutive runs are within the repeatability tolerance listed in GPA 2261-00. The commenters stated that the repeatability tolerances are not applicable to the analysis of field samples and that they only apply to calibration gas. One commenter stated that it can be difficult to extract more than three samples from a sample cylinder due to its limited volume and several commenters stated that it would be expensive and time consuming to meet the GPA repeatability standard for each sample. Several commenters stated that this is not applicable for portable GCs because the composition of the gas may actually change as more samples are run through the GC. Some commenters suggested that the rule require two consecutive runs, but only for calibration and verification. The BLM agrees with these comments and deleted this requirement altogether for laboratory GCs.

The BLM believes that some criteria for portable GCs are needed and added a repeatability requirement to § 3175.113(d)(5) as a result. For high-volume FMPs, the operator must continue to analyze samples until three consecutive samples result in a difference between the maximum and minimum heating value of 16 Btu/scf or less. For very-high-volume FMPs, the limit is 8 Btu/scf. These limits were derived from the statistical method used in API 4.2, Appendix C, for determining the maximum allowable difference between proving runs necessary to achieve a set level of uncertainty. The equation used for this determination in Appendix C is:

$$(a)MF = \frac{w(MF) \times t(\%, n-1)}{D(n) \times \sqrt{n}}$$

where:

(a)MF = uncertainty of the average in the meter proving set

(w)MF = (high value – low value) of n runs in the proving set, divided by the average of the data set

t(%,n-1) = student "t" function, where the percentage is the confidence level and n is the number of proving runs

D(n) = factor that converts (high value – low value) to standard deviation

This equation is equally applicable to heating value deviation in successive gas analysis runs and is rewritten by substituting "HV" (heating value) for "MF" (meter factor):

$$(a)HV = \frac{w(HV) \times t(\%, n-1)}{D(n) \times \sqrt{n}},$$

where:

(a)HV = uncertainty of the average in the gas analysis set;

(w)HV = (high value – low value) of n runs in the proving set, divided by the average of the data set; and

n = the number of consecutive samples used for analysis.

The accuracy of the heating value uncertainty in the data analysis set is defined as the average annual uncertainty in § 3175.31(b), which is 2 percent for high-volume FMPs and 1 percent for very-high-volume FMPs. The BLM realizes that average annual heating value uncertainty is not the same as the uncertainty of average heating value in the data analysis set. In reality, the uncertainty of the average heating value in the data analysis set should be much less than the average annual heating value uncertainty, perhaps as much as five times less. For example, in § 3174.11, the allowable meter factor difference between provings is 0.25 percent, while the maximum allowable deviation between meter factors during a proving is 0.05 percent. The allowable meter factor difference is analogous to the average annual heating value and the maximum allowable deviation between meter factors during a proving is analogous to the maximum allowable deviation between consecutive heating values when using a portable GC. For high-volume FMPs, a value of 2 percent is substituted for *(a)HV* in the equation above, the value of *t* for a 95percent confidence level and three samples is 4.303, and the value of *D(n)* for three samples is 1.693. With these values, the above equation is solved for *w(HV)* as follows:

$$w(HV) = \frac{a(HV) \times D(n) \times \sqrt{n}}{t(\%, n-1)} = \frac{0.02 \times 1.693 \times \sqrt{3}}{4.303} = 0.013.$$

The result of this equation (0.013 or 1.3 percent) is the maximum deviation allowed between the maximum and minimum heating value determined over three consecutive samples that will result in a data set uncertainty of 2 percent. Using an average heating value of 1,200 Btu/scf, the maximum allowable deviation in heating value is 16 Btu/scf. For very-high-volume FMPs (one percent uncertainty), the maximum allowable deviation is 8 Btu/scf. The BLM believes that, in practice, heating value variability over three consecutive samples is well within this tolerance in most cases.

§ 3175.118(c)

In the final rule, the BLM combined § 3175.118(c) through (h) of the proposed rule into § 3175.118(c) because all of these paragraphs address the calibration of GCs.

Therefore, comments relating to the provisions of § 3175.118(c) through (h) of the proposed rule are all addressed here.

Proposed § 3175.118(c) would have set a minimum frequency for verification of GCs. More frequent verifications would have been required for portable GCs (§ 3175.118(c)(1) of the proposed rule) because these devices may be exposed to field conditions such as temperature changes, dust, and transportation effects. All of these conditions have the potential to affect calibration. In contrast, laboratory GCs (§ 3175.118(c)(2) of the proposed rule) are not exposed to these conditions; therefore, they do not need to be verified as often.

The BLM received several comments objecting to the requirement in § 3175.118(c)(1) of the proposed rule to verify a portable GC within 24 hours of taking a sample at an FMP. The commenters stated that daily verification of a GC is impractical because of the time it takes to do the verification and that the calibration facility is at a fixed location. One commenter stated that daily verification is not needed if the lab follows strict quality control procedures. The BLM agrees with these comments and changed the verification frequency for portable GCs to coincide with that for laboratory GCs (once every 7 days) and moved the requirement to § 3175.118(c)(1).

Proposed § 3175.118(d) would have required that the gas used for verification be different than the gas used for calibration. This requirement was proposed because it is relatively easy to alter the composition of a reference gas if it is not handled properly. An errant reference gas used to calibrate a GC would not be detected if the same gas is used for verification, which could lead to a biased heating value.

The BLM received several comments objecting to the requirement in proposed § 3175.118(d). These comments recommended deleting this provision because compromised calibration gas can be detected with quality control procedures such as monitoring the response factors of the calibration gas. The commenters also stated that neither GPA nor API require this and the operator would have to have two bottles of certified calibration gas which is expensive. The BLM agrees with these comments and deleted the requirement as a result. However, in its place, the BLM added minimum quality control requirements to the final rule. These requirements are in: § 3175.118(c)(3), which requires the operator to authenticate all new gases under the standards of GPA 2198-03, Section 5; § 3175.118(c)(4), which requires the operator to maintain the gas under GPA 2198-03, Section 6; and § 3175.118(c)(5), which requires a GC to be calibrated if the composition of the calibration gas as determined by the GC varies from the certified composition of the calibration gas by more than the reproducibility values listed in GPA 2261-13, Section 10.

Section 3175.118(c)(5) (§ 3175.118(e) in the proposed rule) would have required a calibration of the GC if the repeatability identified in GPA 2261-00, Section 9, could not be achieved during a verification.

Numerous comments objected to this and said that the intent of the GPA standard cited was only for replication of the same sample. The BLM agrees with these comments and changed the wording to reference the “reproducibility” standard in GPA 2261-13, instead of the repeatability standard. The BLM believes this change is appropriate because it accounts for differences in analyzing the same sample between different laboratories. The different laboratories are, in this case, the laboratory from which the calibration gas originated and the laboratory receiving and testing the calibration gas. The BLM also updated the reference from GPA 2261-00 in the proposed rule to GPA 2261-13 in the final rule.

Section 3175.118(f) in the proposed rule, requiring a GC to be re-verified if a calibration was performed, was moved to § 3175.118(c)(6) in the final rule. The BLM did not receive any comments on this section.

The requirement in § 3175.118(h) of the proposed rule for all calibration gases to meet the standards of GPA 2198-03 was moved to § 3175.118(c)(2) of the final rule. The BLM did not receive any comments on this paragraph.

§ 3175.118(d)

Section 3175.118(d) requires documentation of the verification, calibration, and quality control process, which includes the requirements from § 3175.118(i) in the proposed rule. This section requires the documentation to be retained as required under the record-retention requirements in 43 CFR 3170.6 and provided to the BLM on request. For portable GCs, the rule (§ 3175.113(d)(4)) requires documentation to be available onsite. The purpose of the latter requirement is that it allows the BLM to inspect the verification documents while witnessing a spot sample that is taken with a portable GC. If the verification has not been performed in accordance with the requirements of § 3175.118(d), the GC cannot be used to analyze the sample.

The BLM added three new requirements to the documentation requirements in this section (proposed § 3175.118(i)). These new requirements will help ensure that operators are implementing the quality-control measures required in the final rule in lieu of the requirement in the proposed rule to use a different gas for verification than was used for calibration. Section 3175.118(d)(7)(ii) requires documentation that new calibration gas was authenticated under § 3175.118(c)(3), and § 3175.118(d)(7)(iii) requires documentation that calibration gas was maintained under § 3175.118(c)(4). Section 3175.118(d)(8) also requires the documentation to include the chromatograms generated during the verification process.

§ 3175.118(e)

The BLM received several comments stating that GPA 2261-13 is intended for analyses through hexanes-plus and should not be used for the extended analysis that the BLM is requiring under § 3175.119(b). The commenters recommended that the BLM incorporate by reference GPA 2286-14, which is used for extended analysis. The BLM agrees with these comments and added § 3175.118(e) to the final rule to require extended analyses to be taken in accordance with GPA 2286-14, which is incorporated by reference in the final rule. This paragraph allows the BLM to approve other methods as well.

§ 3175.119 – Components to analyze

Section 3175.119(a) of the final rule requires gas analyses through hexane+ (C_6+) for all low- and very-low-volume FMPs. For high- and very-high-volume FMPs where the concentration of C_6+ exceeds 0.5 mole percent, the operator has two options. One option (§ 3175.119(b)) is for the operator to take an extended analysis (through C_9+) every time the sample exceeds 0.5 mole percent of C_6+. The other option (§ 3175.119(c)) is for the operator to take periodic extended analyses and adjust the hexane-heptane-octane split (see § 3175.126(a)(3)) based on those periodic analyses to eliminate any heating value bias that may exist. The second option could be more attractive to operators of FMPs that consistently have concentrations of C_6+ in excess of 0.5 mole percent.

Analysis through C_6+ is common industry practice and does not represent a significant change from existing procedures. Although components heavier than hexane exist in gas streams, these components are typically included in the C_6+ concentration given by the GC by using an assumed split of hexane, heptane, and octane. Under proposed § 3175.126(a)(3), the heating value of C_6+ would have been derived from an assumed gas mixture consisting of 60 mole percent hexane, 30 mole percent heptane, and 10 mole percent octane. At concentrations of C_6+ below the 0.25 mole percent threshold given in proposed § 3175.119(b), the uncertainty due to the assumed gas mixture given in § 3175.126(a)(3) does not significantly contribute to the overall uncertainty in heating value and would not significantly affect royalty.

Proposed § 3175.119(b) would have required an extended analysis of the gas sample, through nonane+, if the concentration of C_6+ from the standard analysis is 0.25 mole percent or greater. As indicated in Table 1 to § 3175.110, this requirement does not apply to very-low-volume FMPs or low-volume FMPs. The threshold of 0.25 mole percent was derived through numerical simulation of the assumed composition of C_6+ (60 mole percent hexanes, 30 mole percent heptanes, and 10 mole percent octanes) compared to randomly generated values of hexanes, heptanes, octanes, and nonanes. The numerical simulation showed that the additional uncertainty of the fixed C_6+ mixture required in § 3175.126(a)(3) does not significantly add to the heating value uncertainties required in § 3175.31(b), until the mole percentage of C_6+ exceeds 0.25 mole percent. In the proposed rule, the BLM sought data that confirms or refutes the results of our numerical simulation. Specifically, we sought data comparing heating values determined with a C_6+ analysis with heating values of the same samples determined through an extended analysis.

The BLM received multiple comments objecting to the requirement to perform an extended analysis because, according to the commenters, extended analyses are expensive and provide little royalty or revenue benefit. The BLM received one comment that the 60-30-10 split of C_6+ approximates the result of a C_6+ analysis in a fair and equitable manner, and that the BLM should consider custom splits only in locations with high C_6+ concentrations.

One commenter indicated that the difference in heating value between a C_6+ analysis and an extended analysis is less than the accuracy of the GC, and therefore, is not significant. Several commenters submitted data showing the difference in heating value based on a C_6+ analysis and an extended analysis. The BLM analyzed these data and generated a graph showing the difference in heating value between a C_6+ analysis and an extended analysis as a function of the mole percentage of C_6+, assuming a 60-30-10 split of hexane, heptane, and octane, respectively (Figure 2).

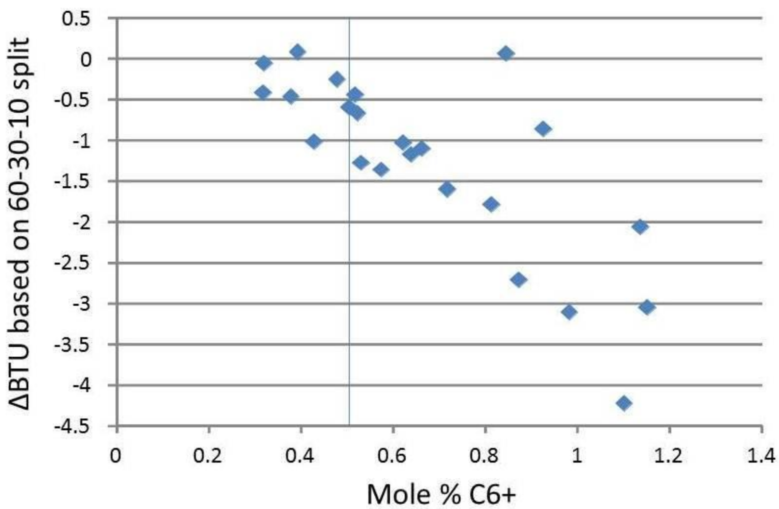

Figure 2

The BLM does not believe that Figure 2, generated from the data supplied by the commenters, supports the commenter's conclusions that the difference between an extended analysis and a C_6+ analysis is less than the accuracy of a GC and is not significant or necessary. To analyze these data, the BLM first determined whether the apparent bias in the data as the mole percent of C_6+ increases is statistically significant. To do this, the BLM used the reproducibility column from Table VI of GPA 2261-13, which gives an indication of the amount of deviation a given component will exhibit when a sample containing that component is analyzed at different laboratories. The BLM then applied these reproducibilities to an assumed gas analysis that resulted in a heating value similar to the heating values supplied by the commenter (approximately 1,119 Btu/scf) using a "Monte Carlo" methodology. From this analysis, the uncertainty in any given heating value is approximately ±2 Btu/scf at a 95 percent confidence level. The threshold of significance, using the definition provided in subpart 3170 is:

$$T_s = \sqrt{U_a^2 + U_b^2}$$

where:

T_s = threshold of significance

U_a = the uncertainty of data set a

U_b = the uncertainty of data set b

Because this analysis compares data points to each other, the uncertainty of both data sets “a” and “b” is ±2 Btu/scf, which yields a threshold of significance of ±2.8 Btu/scf. In other words, any difference between two data points that is greater than ±2.8 Btu/scf is statistically significant, and is outside the uncertainty associated with the gas chromatograph that derived these data points. From Figure 2, there are three points that fall outside of the ±2.8 Btu/scf threshold at the bottom right-hand part of the graph. These three points include three of the four highest mole percentages of C_6+ included in the data (1.0, 1.1, and 1.15 mole percent C_6+). As a result, the BLM concludes that the data presented by the commenters indicates a statistically significant bias associated with the assumed 60-30-10 split of C_6+ when the mole percent of C_6+ is 1.0 mole percent or higher. Therefore, the BLM disagrees with the comment that the difference in heating value between a C_6+ analysis and an extended analysis is less than the accuracy of the GC, and therefore it is not significant. The BLM did not make any changes to the rule based on these comments.

Commenters also made various suggestions regarding extended analysis that included not requiring an extended analysis in any circumstance and adjusting the C_6+ threshold for requiring an extended analysis to a higher percentage (suggested values ranged from 0.5 mole percent to 1.0 mole percent). The BLM agrees with the comments suggesting a different threshold and changed the threshold at which an extended analysis is required from 0.25 mole percent in the proposed rule to 0.50 mole percent in the final rule. Not only does Figure 2 show a bias in the heating value when the mole percent of C_6+ exceeds 1.0 mole percent (assuming a C_6+ split of 60-30-10 hexane, heptane, and octane, respectively), Figure 2 also suggests a correlation (correlation coefficient of 0.61) between the concentration of C_6+ and heating value.

The BLM notes that Figure 2 is based on one data set that contains a fairly narrow range of heating values (1,086 Btu/scf to 1,181 Btu/scf) and, as such, may not be representative of potential bias or correlations that exist outside of that heating value range. Based on the threshold of significance analysis describe above, the BLM agrees that the 0.25 mole percent threshold from the proposed rule is too low and most likely would be less than the uncertainty of most GCs. However, the BLM believes that a threshold of 1 mole percent of C_6+ is too high because the evidence supplied by one of the commenters (Figure 2) demonstrates that statistically significant bias is already present when the mole percent of C_6+ reaches 1 percent. As a result, the BLM raised the threshold to 0.5 mole percent of C_6+, which is one of the thresholds suggested by a commenter. The BLM believes that the 0.5 mole-percent threshold is a reasonable balance between ensuring that heating values are not biased and reducing the economic burden to operators associated with the 0.25 mole percent threshold in the proposed rule.

Several commenters suggested that instead of requiring an extended analysis every time the C_6+ analysis exceeds the threshold, the operator could periodically perform an extended analysis and, based on that analysis, could adjust the C_6+ split (hexane, heptane, and octane) to eliminate any bias. The BLM agrees with this comment and included a new § 3175.119(c) that will allow this in lieu of performing an extended analysis every time the mole percent exceeds the threshold. If the operator chooses this option, the new paragraph requires an extended analysis once per year for high-volume FMPs and twice per year for very-high-volume FMPs.

One commenter suggested basing the threshold on the Btu content in combination with the mole percentage of C_6+. The BLM analyzed the suggestion of basing the threshold on the Btu content rather than on the mole percentage of C_6+. Figure 3 shows the same data as in Figure 2, but plotted against heating value instead of the mole percentage of C_6+. Based on an analysis of Figure 3, the BLM believes the relationship between heating value difference and heating value (correlation coefficient of 0.24) is much less clear than the relationship between heating value difference and concentration of C_6+; therefore, the BLM did not adopt the suggestion to base the threshold on heating value.

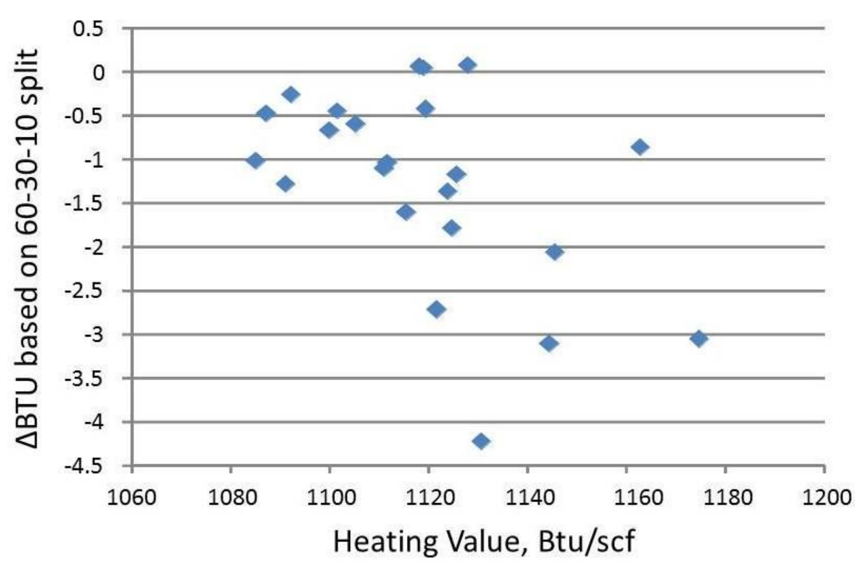

Figure 3

One commenter provided some cost data to show the additional cost of requiring extended analyses as compared to a standard C_6+ analysis. While the BLM acknowledges that extended analyses are more expensive than C_6+ analyses, the changes made to the final rule (increasing the threshold from 0.25 mole percent C_6+ to 0.50 mole percent C_6+ and allowing periodic extended analysis to adjust the hexane, heptane, octane split) will minimize these costs. In addition, the BLM considered these costs in determining the thresholds for the various flow-rate categories (see the BLM Threshold Analysis). However, in the Threshold Analysis, the cost of complying with the requirements in the final rule relating to volume measurement were higher than the cost of complying with the requirements in the final rule relating to heating value determination. Therefore, the thresholds are based on the cost of volume determination rather than on the costs of heating value determination. The BLM did not make any changes based on this comment.

Several commenters objected to the BLM simulation used to determine the 0.25 mole percent threshold and the significant variance in heating value which resulted from the simulation. Other commenters requested that the simulation be provided for review, and suggested further review prior to implementing this rule. Multiple commenters expressed concern over the availability or ability of many labs to provide the extended analysis, and whether measurement systems are able to handle the extended analysis input. The BLM did not make any changes to the rule based on these comments. The BLM did not provide the simulation because it only established the basis for the proposed threshold. The BLM specifically asked for data showing the difference between C_6+ analysis and an extended analysis as a function of the concentration of C_6+ and based the final threshold on this data. The BLM was unable to evaluate comments concerning the laboratory’s ability to perform C_6+ analysis, and those that contended measurement systems may not be able to take a C_6+ analysis as input, because the commenters did not supply data or rationale to support their comment. A comment also stated that low-volume and very-low-volume FMPs should be exempt from uncertainty of heating value, and that extended analysis should only be required once per year. Low- and very-low-volume FMPs were exempt from the extended analysis requirement in the proposed rule, and are still exempt in the final rule, as shown in Table 1 to § 3175.110. The BLM did change the rule by adding § 3175.119(c) which allows operators of high-volume FMPs the option of performing an extended analysis once per year; operators of very high-volume FMPs have the option of performing a semi-annual extended analysis.

§ 3175.120 – Gas analysis report requirements

Section 3175.120 establishes minimum standards for the information that must be included in a gas analysis report. This information allows the BLM to verify that the sampling and analysis comply with the requirements in § 3175.110, and enables the BLM to independently verify the heating value and relative density used for royalty determination.

Section 3175.120(a) establishes the minimum requirements for the information required in a gas analysis report. The BLM did not receive any comments on this paragraph.

Section 3175.120(b) requires that gas components not tested be annotated as such on the gas analysis report. It is common practice for industry to include a mole percentage for each component shown on a gas analysis report, even if there was no analysis run for that component. For example, the gas analysis report might indicate the mole percentage for hydrogen sulfide to be “0.00 percent,” when, in fact, the sample was not tested for hydrogen sulfide.

The BLM received several comments objecting to this requirement because they said it would take time and money to implement and may require reprogramming of some systems. For the following reasons, the BLM did not make any changes to the rule based on these comments. The BLM believes that the current practice of reporting zero concentration for untested components is misleading and potentially dangerous, especially for components such as hydrogen sulfide. For example, if a gas analysis report shows a concentration of zero for hydrogen sulfide, the person looking at the analysis could falsely conclude that there is no hydrogen sulfide present. This could have serious safety consequences. Unless an extended analysis is run, concentrations of hexanes, heptanes, octanes, and nonanes are not individually tested; however, many gas analyses report zero for these concentrations. Because the BLM is requiring extended analyses in some cases (see § 3175.119 (b)), the reporting of zero for hexanes, heptanes, octanes, and nonanes, when these components are not tested, is misleading because it could indicate that an extended analysis was run when it was not. Although the commenters did not quantify for the BLM the additional time and expense they would incur from this requirement, the BLM believes that it would be negligible. One commenter suggested that a blank or null entry of a component in a gas analysis could be used to indicate that it was not tested. While the BLM agrees with this comment, no changes were made to the rule because the suggestion would satisfy the requirement as written.

Section 3175.120(c) specifies that heating value and relative density must be calculated under API 14.5, while § 3175.120(d) specifies that supercompressibility be calculated under AGA Report No. 8. The BLM changed the reference from API 14.2 in the proposed rule to AGA Report No. 8 in the final rule because the BLM determined that the API 14.2 standard primarily referenced the AGA Report No. 8 standard. The BLM believes that the latter is the most appropriate source for the supercompressibility calculations.

One commenter stated that the rule needs to specify the version and date of API 14.5 and API 14.2, and went on to suggest that the BLM should adopt the new standards for calculating the thermodynamic properties of gas in 14.2.1 and 14.2. The BLM did not make any changes to the rule as a result of this comment because the incorporation by reference section of the rule (§ 3175.30) already specifies the version and date. The new version of API 14.2 that the commenter refers to is not yet publically available; therefore the BLM cannot incorporate it. As noted above, the BLM references AGA Report No. 8 in the final rule instead of API 14.2.

Proposed § 3175.120(e) would have required operators to submit all gas analysis reports to the BLM within 5 days of the due date for the sample. For high-volume and very-high-volume FMPs, the gas analyses would be used to calculate the required sampling frequencies under § 3175.115(c). Requiring the submission of all gas analyses allows the BLM to verify heating-value and relative-density calculations and it allows the BLM to determine operator compliance with other sampling requirements in proposed § 3175.110. The method of determining gas sampling frequency for high-volume and very-high-volume FMPs assumes a random data set. The intentional omission of valid gas analyses would invalidate this assumption and could result in a biased annual average heating value. This could be considered tampering with a measurement process under 43 CFR 3170.4.

The BLM received many comments objecting to the 5-day timeframe to submit gas analyses to the BLM. The comments stated that 5 days is not reasonable because of the process required to obtain the analysis, send it out to a laboratory, get it analyzed, and then evaluate the analysis. Commenters suggested timeframes ranging from 15 days to 30 days. The BLM agrees with these comments and changed the timeframe from 5 days to 15 days. The BLM believes that 15 days is a reasonable amount of time in which to obtain, analyze, evaluate, and submit the results to the BLM. The BLM did not opt for a longer period of time because this could cause confusion when, for example, the required sampling frequency is twice per month. In this case, a longer timeframe could result in overlapping periods of time.

One commenter questioned how an operator would meet the 5-day reporting timeframe in the proposed rule if the well is not flowing at the time the sample was due. The BLM addresses this situation in § 3175.113(a) of both the proposed and final rule. If the FMP is not flowing at the time the sample is due, the operator has 15 days from the resumption of flow to sample the FMP.

Proposed § 3175.120(f) would have required operators to submit all gas analysis reports to the BLM using the GARVS online computer system that the BLM is developing. Under the proposed rule, operators would have been required to submit all gas analyses electronically, unless the operator is a small business, as defined by the U.S. Small Business Administration, and does not have access to the Internet. The BLM received numerous comments on this requirement stating that the BLM should delay implementation of this requirement until GARVS is developed and the industry knows what the system requirements will be. The BLM agrees with this comment and is delaying this requirement for 2 years from the effective date of this rule. For further discussion of GARVS implementation, see the earlier discussion of § 3175.60.

§ 3175.121 – Effective date of a spot or composite gas sample

Proposed § 3175.121 would have established an effective date for the heating value and relative density determined from spot or composite sampling and analysis. Section 3175.121(a) establishes the effective date as the date on which the spot sample was taken unless it is otherwise specified on the gas analysis report. For example, industry will sometimes choose the first day of the month as the effective date to simplify accounting. While the BLM believes this is an acceptable practice, there is a need to place limits on the length of time between the sample date and the effective date based on inconsistencies found as part of the Gas Variability Study discussed earlier. Section 3175.121(b) establishes that the effective date can be no later than the first day of the month following the date on which the operator received the laboratory analysis of the sample. This accounts for the delay that often occurs between taking the sample, obtaining the analysis, and applying the results of the analysis. If, for example, a sample were taken toward the end of March, the results of the analysis may not be available until after the first of April. Section 3175.121(b) would allow the effective date to be the first of May. Based on the Gas Variability Study conducted by the BLM, the timing of the effective date of the sample is less important than the timing of the samples taken over the year.

Proposed § 3175.121(c) would have required the effective dates of a composite sample to coincide with the time that the sample cylinder was collecting samples. A composite sampling system takes small samples of gas over the course of a month or some other time period, and places each small sample into one cylinder. At the end of that time period, the cylinder contains a gas sample that is representative of the gas that flowed through the meter over that time period. Therefore, the proposed rule would have established the effective date as the date on which the composite sample cylinder was installed.

The BLM received multiple comments objecting to the requirement that the installation date of the composite sample cylinder should be the effective date of the sample. The commenters argued that sample cylinders on composite samplers are typically removed the last week of the month and the heating value and relative density from that sample are applied for the whole month. The new cylinder is installed immediately after the old cylinder is removed. If the effective date is the day the cylinder is installed, as required in the proposed rule, the heating value and relative density would be extrapolated back nearly a month. This, according to commenters, is not consistent with industry practice. The BLM agrees with these comments and made two changes to the rule as a result. First, the BLM changed the effective date for the composite sample from the first of the month that the sample cylinder was installed, to the first of the month that the sample cylinder was removed. Second, the BLM added language that allows the BLM to accept other methods, as long as they are specified on the gas analysis report.

The BLM received one comment suggesting that the proposed effective date of spot or composite gas sample would cause retroactive adjustments on past volumes, heating value and prior period corrections resulting in resubmission of OGORs, with little or no impact on royalty significance. In response to this comment, the BLM added § 3175.121(d) to clarify that the requirements of this section only apply to reports generated after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

§ 3175.125 – Calculation of heating value and volume

Section 3175.125(a) defines how the operator must calculate heating value. Section 3175.125(a)(1) and (2) define how to calculate the gross and real heating value. The calculation and reporting of gross and real heating value are standard industry practices.

Section 3175.125(b)(1) establishes a standard method for determining the average heating value to be reported for a lease, unit PA, or CA, when the lease, unit PA, or CA contains more than one FMP. Consistent with current ONRR guidance (Minerals Production Reporter Handbook, Release 1.0, 05/09/01, Glossary at 14), this method requires the use of a volume-weighted average heating value to be reported. Section 3175.125(b)(2) establishes a requirement for determining the average heating value of an FMP when the effective date of a gas analysis is other than the first of the month. This methodology also requires a volume-weighted average for determining the heating value to be reported. Although this is not specifically addressed in the Reporter Handbook, the method is consistent with the volume-weighted average proposed for multiple FMPs. The BLM did not receive any comments on this section.

§ 3175.126 – Reporting of heating value and volume

Section 3175.126 defines the conditions under which operators must report the heating value and volume for royalty purposes.

§ 3175.126(a)

The reporting of gross and real heating value in § 3175.126(a) is consistent with standard industry practice. The BLM did not receive any comments on this paragraph.

Section 3175.126(a)(1) requires operators to report the “dry” heating value (no water vapor) unless they make an onsite measurement of water vapor using a method approved by the BLM. This could be a change for some operators because gas sales contracts often call for “wet” or as-delivered heating values to be used. The BLM has determined that “wet” heating values almost always bias the heating value to the low side because the definition of “wet” heating value assumes the gas is saturated with water vapor at 14.73 psi and 60°F. If the actual flowing pressure of the gas is greater than 14.73 psi or the actual flowing temperature is less than 60°F, the use of a “wet” heating value will overstate the amount of water vapor that can be physically present, and, therefore, understate the heating value of the gas. Therefore, the BLM is requiring a “dry” heating value determination unless the actual amount of water vapor is physically measured and reported on the gas analysis report. This requirement is consistent with established BLM practice as reflected in BLM Washington Office Instruction Memorandum (IM) 2009-186, dated July 28, 2009.

The BLM would have considered allowing an adjustment in heating value for assumed water-vapor saturation at flowing pressure and temperature (sometimes referred to as “as delivered”) in the final rule if sufficient data had been presented in the public comments to determine under what flowing conditions the assumption is valid; however, no data were submitted with the public comments.

This section also defines the acceptable methods to measure water vapor: The BLM may approve a chilled mirror, a laser detection system, and other methods reviewed by the PMT and approved by the BLM. Stain tubes and other similar measurement methods are not allowed because of the high degree of uncertainty inherent in these devices.

The BLM received multiple comments objecting to the proposed requirement that heating value must be reported "dry." These comments indicate that "dry" Btu creates a bias, and recommend that the BLM adopt the water-vapor adjustment methods in GPA 2172. One commenter stated that water saturation was closer to as-delivered than dry. While the BLM agrees that most gas may have some degree of water saturation, the commenters did not submit any data to substantiate their argument that the gas is saturated or the degree to which the gas is saturated. The BLM received proprietary data from one operator outside of the comment period on the proposed rule that clearly show that gas is not consistently saturated with water vapor. According to this data, saturation levels range from 20 percent to 100 percent. Again, no data to the contrary was submitted by any of the commenters. Assuming that gas is always 100 percent saturated with water vapor would cause a bias in the reported heating value, which would result in the underpayment of royalty. The BLM does not contest that the requirement to report all heating values on a dry basis probably results in a bias as well. However, under paragraph (a)(1) of this section, industry has the option of measuring water vapor or developing other methods to remove this potential bias. The BLM would have no recourse for the low bias resulting from allowing operators to report on an as-delivered basis. The BLM did not make any changes to the rule as a result of these comments.

Several comments indicated that the water saturation levels on low pressure wells (e.g., coalbed methane wells) are nearly impossible to obtain with current technologies, and determining water saturation is prohibitively expensive in general gas analysis. One comment suggested that all wells should have water vapor content measured and that water vapor saturation should be measured on the same frequency as Btu determination.

The BLM is not requiring operators to measure water vapor; this is an economic decision the operator must make. If the operator believes that the additional royalty they are paying on a dry heating value is more than the cost of installing and operating water vapor measurement equipment, the operator would have an economic incentive to purchase the equipment. If the operator chooses not to install water vapor measuring equipment, then the public and Indian tribes will not suffer any financial loss as a result. In addition, the BLM does not require wellhead measurement, but measurement prior to removal or sales from the lease, unit PA, or CA, unless otherwise approved by the AO. Therefore, if an operator believes that wellhead measurement of water vapor is prohibitively expensive, the operator could combine the production from multiple wells within a lease, CA, or unit PA and measure the combined stream without needing approval from the BLM. The BLM did not make any changes to the rule as a result of these comments.

Other comments suggested that the BLM should accept the as-delivered basis until operators and the BLM can figure out a better way to estimate water vapor content, and that the presence of free water during an inspection indicates that the gas is saturated. The BLM rejects the idea of using the as-delivered basis as the default until the BLM and industry can figure out a better way to estimate water-vapor content. If the BLM were to accept the as-delivered basis as the default, industry would have no economic incentive to pursue more accurate measurement techniques. The BLM also rejects the notion that the presence of free water indicates the gas is saturated with water vapor. While that argument may be true at the time when the inspection was made, it is also possible that the free water will disappear when, for example, the temperature rises, thereby increasing the amount of water vapor the gas can hold. The BLM did not make any changes to the rule as a result of these comments.

One commenter requested more time to collect data. The BLM rejects the idea of granting more time for industry to collect data. The BLM has been publicly asking for water vapor data at API meetings for at least 6 years. The BLM did not make any changes to the rule as a result of this comment.

Another commenter expressed concerns over the conflict between BLM regulations requiring a dry heating value and State regulations requiring the heating value to be reported on some other basis. The BLM did not make any changes as a result of these comments. The BLM does not believe that the requirement to report a dry heating value conflicts with State regulations. The BLM understands that State reporting requirements may differ from the BLM and ONRR's requirements for reporting of Federal and Indian production. This difference is currently seen in reporting of gas volumes, in that some states require a pressure base of 15.05 psia, or 14.65 psia, whereas the BLM requirement is 14.73 psia. The BLM does not see this difference as a conflict, just a variable way to report heating value. The BLM did not make any changes to the rule as a result of this comment.

Section 3175.126(a)(2) requires the heating value to be reported at 14.73 psia and 60°F. This requirement is consistent with ONRR regulations at 30 CFR 1202.152(a)(1)(ii). The BLM received a comment cautioning that heating value and volume must be reported at the same pressure or temperature and objecting to the requirement to report heating value at any other standard (such as 14.73 psia and 60°F), than that specified in the sales contract. The BLM did not make any changes as a result of this comment. The BLM acknowledges that the volume and heating value reported on the monthly OGOR should be at the same pressure and temperature. ONRR requires that all volumes and heating value be reported at a standardized pressure of 14.73 psia and 60°F, even when this standard conflicts with the gas sales contract. Both the gas volume calculation methods (§§ 3175.94 and 3175.103) and the heating value calculation methods (see § 3175.126(a)(2)) require a base pressure of 14.73 psia and 60°F.

The composition of C_6+ that would have been required under the proposed rule for heating value and relative density calculation is given in § 3175.126(a)(3). This composition is based on examples shown in API 14.5, Annex B.

The BLM received one comment suggesting that if an operator has better data for this split, they should be able to use it, and requested an example of how the BLM would implement this. Another comment indicated that the "actual" composition, not the "deemed" composition should be used. The BLM agrees with these comments and added a paragraph to the final rule that would allow operators to use a hexane-heptane-octane split that is derived from an extended analysis taken under § 3175.119(c). In this scenario, operators would take periodic extended analyses when the composition of C6+ exceeds 0.50 mole percent, and use the actual extended analysis to derive a hexane-heptane-octane split that they would apply to the C6+ analyses until they took the next required extended analysis. For analyses that are 0.50 mole percent or less of C6+, the operator does not have to run an extended analysis and could use the 60-30-10 split in paragraph (a)(3)(i) of this section. See the discussion under § 3175.119(b) for a further discussion of the impact of C6+ on heating value.

One commenter requested the reference for using the 60-30-10 split. The BLM did not make any changes to the rule based on this comment. The reference for this split was given in the preamble to the proposed rule (see 80 FR 61678).

§ 3175.126(b)

Section 3175.126(b) describes the way in which gas volume must be reported by operators for royalty purposes. Section 3175.126(b)(1) prohibits the practice of adjusting volumes for assumed water vapor content, since this is currently done in some cases in lieu of adjusting the heating value for water vapor content. This results in the volume being underreported. The BLM would have considered allowing a volume adjustment for water vapor if sufficient data were submitted during the public comment period to support an adjustment, as discussed above. No data were submitted, however.

Section 3175.126(b)(2) will require the unedited volume on a QTR (EGM systems) or an integration statement (mechanical recorders) to match the volume reported for royalty purposes, unless edits to the data can be justified and documented by the operator. The BLM did not receive any comments on this paragraph.

§ 3175.126(c)

Proposed § 3175.126(c) would have established new requirements for edits and adjustments to volume or heating value. Section 3175.126(c)(1) would have set requirements as to how operators would adjust volumes and heating values if measuring equipment is out of service or malfunctioning. The BLM received several comments regarding the methodology required for error correction and/or adjustment of volume or heating value on a QTR. One comment indicated the methods were too prescriptive, and a second comment recommended adding wording to § 3175.126(c)(1)(i). The BLM agrees that the required methodology in proposed § 3175.126(c)(1)(i) and (ii) was too prescriptive, and determined that documentation required by § 3175.126(c)(2) and (3) allows adequate determination of the cause of the error and the adjustment methodology utilized to correct volume errors. Therefore, The BLM deleted § 3175.126(c)(1)(i) and (ii).

Section 3175.126(c)(2) requires documentation justifying all edits made to data affecting volumes or heating values reported on the OGORs. While the BLM recognizes that meter malfunctions and other factors can necessitate editing the data to obtain a more correct volume, this section requires operators to thoroughly justify and document the edits made. This includes QTRs and integration statements. The operator must retain the documentation as required under 43 CFR 3170.7 and submit it to the BLM upon request. The BLM did not receive any comments on this section.

Section 3175.126(c)(3) requires that any edited data be clearly identified on reports used to determine volumes or heating values reported on the OGORs and cross-referenced to the documentation required in § 3175.126(c)(2). This includes QTRs and integration statements. The BLM received one comment stating that the requirement to clearly identify all volumes that have been changed or edited would result in changes to industry accounting systems, and require the development of a new interface with OGOR comment reporting. The BLM did not make any changes as a result of this comment. The BLM does not intend to require “comments” on OGORs due to changes or edits to volumes and heating value. The intent of the requirement is to have the operator, purchaser, or transporter document changes, edits and provide justification. The operator must then maintain this documentation and make it available to the BLM upon request.

Section 3175.126(c)(4) requires OGORs submitted to ONRR to be amended when inaccuracies are discovered at an FMP. The BLM did not receive any comments on this paragraph, and made no changes in the final rule.

§ 3175.130 – Transducer testing protocol

Section 3175.130 establishes a testing protocol for differential-pressure, static-pressure, and temperature transducers used in conjunction with differential-flow meters at FMPs. This section was added to implement the requirements in § 3175.31(a) for flow-rate uncertainty limits. To determine flow-rate uncertainty, it is necessary to first determine the uncertainty of the variables that go into the calculation of the flow rate. For differential flow meters, these variables include differential pressure, static pressure, and flowing temperature. Transducers (secondary devices) derive these variables by measuring, among other things, the pressure drop created by the primary device (e.g., an orifice plate). Therefore, the uncertainty of these variables is dependent on the uncertainty of the transducer's ability to convert the physical parameters measured into a digital value that the flow computer can use to calculate flow rate and, ultimately, volume.

Currently, methods used to determine uncertainty (i.e., the BLM Uncertainty Calculator) rely on performance specifications published by the transducer manufacturers. However, the methods that manufacturers use to determine and report these performance specifications are typically proprietary, performed in-house, and the BLM cannot verify them. In addition, the BLM believes that there is little consistency among manufacturers regarding the standards and methods used to establish and report performance specifications.

The testing procedures in §§ 3175.131 through 3175.135 are based, in large part, on testing procedures published by the International Electrotechnical Commission (IEC). Some of these standards are already used by several transducer manufacturers; however it is unknown which manufacturers use which standards or to what extent they do so. Based on numerous comments received under § 3175.43, the BLM will mandate this protocol only for new transducers that are not used at FMPs by the effective date of this rule (see the discussion under § 3175.43).

Numerous comments suggested that the BLM eliminate this requirement and use existing American National Standards Institute (ANSI), International Society of Automation (ISA), National Fire Protection Association (NFPA), GPA, AGA, and API standards instead. The BLM did not make any changes to the rule based on these comments because the BLM is not aware of any standards for testing transducers specific to oil and gas operations.

One commenter asked if the BLM was intending to incorporate the draft API standards 22.4 (transducer testing protocol) and 22.5 (flow-computer software testing protocol) into the final rule. The BLM would have considered incorporating the draft API standards into the rule if they had been published in time. As an alternative, the BLM may seek to amend the regulations once the new API standards are published. The BLM participated in the working groups for both of the draft API standards and believes that, in general, the provisions of the draft standards would be beneficial in accomplishing the goals of a testing protocol. No changes to the proposed rule were made as a result of this comment.

Several comments stated that testing should be the responsibility of the manufacturer, not the operator, and that the BLM should use performance standards rather than require testing of components. See the response to these comments under § 3175.43.

One commenter suggested that the BLM only require testing of those transducers commonly used in the field. The BLM is only requiring testing of transducers that manufacturers or operators want to use on Federal and Indian leases. Therefore, if a manufacturer or operator wants to use a particular transducer, they must have it tested in accordance with this rule. The fact that the transducer is commonly or not commonly used has no bearing on the BLM's acceptance of transducers. The BLM did not make any changes to the rule in response to this comment.

§ 3175.131 – General requirements for transducer testing

Section 3175.131(a) establishes standards for test facilities qualified to perform the transducer-testing protocol. Proposed § 3175.130(a)(1) would have required tests to be carried out by a lab that is not affiliated with the manufacturer to avoid any real or perceived conflict of interest. Traceability to the NIST proposed in § 3175.131(a)(2) was based on IEC Standard 1298-1, section 7.1.

One comment expressed concerns that limiting the standards body to NIST would prevent the use of international labs. The BLM agrees with these comments and added a definition of qualified test facility that refers to NIST or an equivalent international standard.

Numerous comments suggested that the BLM allow in-house testing of transducers because sending transducers to an independent facility would be burdensome and cost prohibitive. In addition, the comments stated, there are very few independent facilities that could perform this testing and they would be overwhelmed by manufacturers trying to comply with this requirement, making it difficult to get the testing done in a timely manner. Some of the commenters suggested that the BLM should allow in-house facilities if they are certified by a national or international standards body such as NIST or ISO. The BLM agrees that transducer testing is specialized and there may not be many independent laboratories capable of performing these tests. Therefore, in the final rule, the BLM does not require this testing to be performed by an independent lab as long as it meets the definition of a "qualified test facility."

In general, the testing requirements in § 3175.131(c) through (h) are based on IEC standard 1298-1, Section 6.7. While the IEC does not specify the minimum number of devices required for a representative number, the BLM is requiring (in § 3175.131(b)(1)) that at least five transducers be tested to ensure testing of a statistically representative sample of the transducers coming off the assembly line. The BLM specifically requested comments on whether the testing of five transducers is a statistically representative sample. The BLM received no comments on paragraphs (c) through (h) of this section.

Section 3175.131(b) requires that the testing protocol be applied to each make, model, and URL of transducers used at FMPs, to ensure that any transducer with the potential to have unique performance characteristics is tested.

One commenter asked if an existing transmitter would have to be replaced if the model was not type tested. First, the requirement to type test transducers does not apply to very-low-volume or low-volume FMPs. Second, under the final rule, existing transducers at high- and very-high-volume FMPs would not have to be replaced as long as the operator or manufacturer submitted the test data the manufacturer used to derive their published performance specifications. The BLM did not make any changes to the rule as a result of these comments.

Two commenters expressed a concern that testing each model number could extend to tens of thousands of variations of transducers. The BLM agrees that there could be confusion over how many combinations of models need to be tested under this section and added language to § 3175.131(b) to clarify what constitutes a "model" (§ 3175.131(b)(3)) and how the testing applies to multi-variable transducers (§ 3175.131(b)(4)). The BLM is only concerned with testing aspects of a transducer that affect its performance. For example, one manufacturer makes the following models of a multi-variable transducer:

Base Model Number	**DP URL***	**SP URL****
3010	100"	150 psia
3020	400"	500 psia
3030	800"	1,500 psia
3040	1,200"	3,000 psia

*DP URL means the upper range limit for differential pressure
**SP URL means the upper range limit for static pressure

A 3-digit model number suffix that is added to each of the base model numbers indicates the output type (three possible combinations), the mounting type (four possible combinations), and the location of the static pressure sensor (two possible combinations). Assuming that the output type, mounting type, and static pressure sensor location do not affect the performance of the transducer, none of these combinations would have to be tested. In addition, language in the final rule clarifies that a particular cell only has to be tested once under the protocol. In this example, the operator or manufacturer would only have to test only eight ranges for this make and model (100", 400", 800", 1,200", 150 psia, 500 psia, 1,500 psia, and 3,000 psia).

Test equipment requirements for field calibrations are listed under § 3175.102(c). One commenter stated that the BLM should not require test equipment used to calibrate transducers in the field to meet the accuracy requirement in § 3175.131(d), which requires the test equipment to be four times more accurate than the equipment being tested. The test equipment accuracy requirements in § 3175.131(d) are specific to transducer type testing. The BLM did not make any changes to the rule in response to this comment.

§ 3175.132 – Testing of reference accuracy and 3175.133 – Testing of influence effects

Sections 3175.132 and 3175.133 establish specific testing requirements for reference accuracy and influence effects. These requirements are based on the following IEC standards: IEC 1298 1, IEC 1298-2, IEC 1298-3, and IEC 60770-1. The testing described in the proposed rule would have required a long-term stability test that would have cycled each transmitter through several influence effects over a period of 24 weeks.

Numerous comments expressed concern about the long-term stability test that would have been required in the proposed rule. The comments stated that this test would cost hundreds of thousands of dollars to perform for each make, model, and range tested, and that there are very few test facilities with the capability to perform this test. The BLM agrees with these comments and removed the requirement for a long term stability test in the final rule. However, removing this requirement raised issues about how the BLM would address long-term stability in the field. To address these issues, the BLM added § 3175.102(c)(3) that requires the operator to replace any transducer if, on two consecutive routine verifications, the as-found values were off by more than the manufacturer's specification for long-term stability, as adjusted for static pressure and ambient temperature. The BLM believes that this requirement will ensure that transducers that exhibit a high degree of drift are identified and replaced.

§ 3175.134 – Transducer test reporting

Section 3175.134 requires documentation of the transducer testing (under §§ 3175.131 through 3175.133 of this subpart) and the submission of the documentation to the PMT. The PMT will use the documentation to determine the uncertainty and influence effects of each make, model, and range of transducer tested. The BLM did not receive any comments on this section.

§ 3175.135 – Uncertainty determination

Section 3175.135 establishes a method of deriving reference uncertainty and quantifying influence effects from the tests required by this protocol. The methods for determining reference uncertainty are based on IEC Standard 1298-2, Section 4.1.7. While the IEC standards define the methods to be used for influence-effect testing, no specific methods are given to quantify the influence effects; therefore, the BLM developed statistical methods to determine zero-based effects and span-based effects. In addition, all uncertainty calculations use a “student t-distribution” to account for the small number of transducers of a particular make, model, URL, and turndown, to be tested. After a transducer has been tested under §§ 3175.131 through 3175.134, the PMT will review the results. Once the BLM approves the device, the BLM will list the approved transducers for use at FMPs (see § 3175.43), and list the make, model, URL, and turndown of approved transducers on the BLM website along with any operating limitations or other conditions. The BLM did not receive any comments on this section.

§ 3175.140 – Flow-computer software testing

Section 3175.140 provides that the BLM will approve a particular version of flow-computer software for use in a specific make and model of flow computer only if the testing is performed under the testing protocol in §§ 3175.141 through 3175.144, to ensure that calculations meet API standards. Unlike the testing protocol for transducers in § 3175.130, which is used to derive performance specifications, the testing protocol for flow computers includes pass-fail criteria. Testing is only required for those software revisions that affect volume or flow rate calculations, heating value, or the audit trail.

Numerous comments suggested that the BLM eliminate this requirement and use existing ANSI, ISA, NFPA, GPA, AGA, and API standards instead. One commenter asked if the BLM was intending to incorporate the draft API standards 22.4 (transducer testing protocol) and 22.5 (flow-computer software testing protocol) into the final rule. See the response to these comments under § 3175.130. The BLM did not make any changes to the rule in response to these comments.

One commenter stated that flow-computer testing will take 3 years to get approved. The BLM disagrees with this comment and did not make any changes to the rule. Assuming the manufacturers perform the testing in accordance with the requirements of this section and submit all required data to the PMT, the review process should be simple and fast.

One commenter stated that the BLM should use uncertainty performance standards instead of requiring testing under this section. The BLM established uncertainty performance goals in § 3175.30 of the proposed rule (§ 3175.31 in the final rule). However, the BLM does not believe that verifying the calculations done by EGM systems is an uncertainty issue. There is no reason that flow-computer software should not be able to accurately calculate the flow rate, volume, heating values, and other parameters, within a very small tolerance of the true values. If the flow-computer software calculates incorrect values, that miscalculation does not reflect uncertainty but bias, because the error in the EGM's software will systematically generate values that are too low (or too high). The BLM did not make any changes to the rule in response to this comment.

Several comments stated that the BLM should have provided the reference software for review. The BLM did not provide the reference software for review because it has not yet been developed. The BLM intends to work with API in developing reference software that is acceptable to all parties. Because the BLM delayed the implementation of the flow-computer software requirements by 2 years, there will be time to establish reference software. The BLM did not make any changes to the rule in response to this comment.

One commenter stated that there should be a process in place to avoid various companies having to test the same software. All software testing required under this section will be reviewed by the PMT. Once a software version is reviewed by the PMT and approved by the BLM, it will be posted on the BLM website and will be approved for use by anyone. This will avoid the potential for different companies having to test the same software. The BLM did not make any changes to the rule in response to this comment.

One commenter asked if a software version that is run in different flow computers would require separate tests for each flow computer under this section. The answer is yes.

Because of the potential for software to run differently on different hardware platforms, the BLM will approve software versions that are specific to a make and model of flow computer on which it was tested. Although no changes to the intent of the final rule were made as a result of this comment, the BLM did add some language to both this section and to § 3175.44 to clarify this intent.

§ 3175.141 – General requirements for flow-computer software testing

The testing procedures in this section are based, in large part, on a testing protocol in API 21.1, Annex E. Section 3175.141(a) requires that all testing be done by an independent laboratory to avoid any real or perceived conflict of interest in the testing.

Several commenters stated that the BLM should allow in-house testing of flow-computer software under this section. The BLM disagrees with these comments because independent testing prevents any real or perceived conflict of interest between the manufacturer and the testing process and it is in the public interest. The BLM is allowing in-house testing of transducers (§ 3175.131(a)) only because transducer testing requires highly specialized equipment that only manufacturers are likely to have and requiring transducer testing at an independent qualified test facility could create an economic burden and delays. However, flow-computer software testing does not require highly specialized equipment and can readily be done by many testing facilities. Because the commenters did not provide any compelling arguments as to why independent testing of flow-computer software is onerous, the BLM did not make any changes to the rule in response to these comments.

Section 3175.141(b)(1) requires that each make, model, and software version tested must be identical to the software version installed at an FMP. Section 3175.141(b)(2) requires that each software version be given a unique identifier, which must be part of the display (see § 3175.101(b)(4)) and the configuration log (see § 3175.104(b)(2)) to allow the BLM to verify that the software version has been tested under the protocol in this section.

One commenter asked how the BLM would handle software versions that do not require testing under this section. For example, if the manufacturer of an EGM system installs a new version of software that does not need to be tested under this section, the commenter asked how this version of the software would get on the approved software list. Although the details of this process will be resolved within the 2-year implementation timeframe that is part of the final rule (see § 3175.60(a)(4) and (b)(1)(iv)), the BLM added a phrase to § 3175.44(b)(2) that states that the operator or manufacturer must provide the BLM with a list of the software versions that do not require testing, along with a brief description of what changes were made from the previous version. If the PMT agrees, the PMT will confirm that the changes described by the manufacturer do not require testing, and then add the software version to the list of approved software versions.

One commenter asked who would determine whether a version of software needs to be tested under this section. The BLM will have to rely on the manufacturer to make that determination, although the process described in the previous paragraph will allow the PMT to verify that the software version did not need to be tested. The BLM did not make any changes to the rule in response to this comment.

Section 3175.141(c) provides that input variables may be either applied directly to the hardware registers or applied physically to a transducer. In the latter event, the values received by the hardware register from the transducer (which are subject to some uncertainty) must be recorded. The BLM did not receive any comments on this section.

Section 3175.141(d) establishes a pass-fail criterion for the software testing. The digital values obtained for the testing in §§ 3175.142 and 3175.143 are entered into BLM-approved reference software, and the resulting values of flow rate, volume, integral value, flow time, and averages of the live input variables are compared to the values determined from the software under test. A maximum allowable error of 50 parts per million (0.005 percent) is established in § 3175.141(d)(2). The BLM did not receive any comments on this section.

§ 3175.142 – Required static tests

Section 3175.142(a) sets out six required tests to ensure that the instantaneous flow rate is being properly calculated by the flow computer. The parameters for each of the six tests set out in Tables 1 and 2 to § 3175.142 are designed to test various aspects of the calculations, including supercompressibility, gas expansion, and discharge coefficient over a range of conditions that could be encountered in the field. The BLM did not receive any comments on this section.

Section 3175.142(b) tests the ability of the software to accurately accumulate volume, integral value, and flow time, and calculate average values of the live input variables over a period of time with fixed inputs applied. The BLM did not receive any comments on this section.

Section 3175.142(c) of the final rule requires that additional tests be performed that assess the ability of the event log to capture all required events, and the software's ability to handle inputs to a transducer that are beyond its calibrated span. Proposed §

3175.142(c)(3) would have required testing the ability of the software to record the length of any power outage that inhibited the computer's ability to collect and store live data. Based on comments received under § 3175.104(c)(1), the BLM eliminated the need for the event log to retain a record of all power outages that inhibit the meter's ability to collect and store new data. Therefore, the BLM removed the provision in this paragraph that would have required testing of this event-logging feature.

§ 3175.143 – Required dynamic tests

Section 3175.143 establishes required dynamic tests that test the ability of the software to accurately calculate volume, integral value, flow time, and averages of the live input variables under dynamic flowing conditions. The tests are designed to simulate extreme flowing conditions and include a square wave test, a sawtooth test, a random test, and a long-term volume accumulation test. A square wave test applies an input instantaneously, holds that input constant for a period of time and then returns the input to zero instantaneously. A sawtooth test increases an input over time until it reaches a maximum value, and then decreases that input over time until it reaches zero. A random test applies inputs randomly. The BLM did not receive any comments on this section.

§ 3175.144 – Flow-computer software test reporting

After a software version has been tested under §§ 3175.141 through 3175.143, the PMT would review the results and make a recommendation to the BLM. If the BLM determines that the test was successful, the BLM would approve the use of the software version and flow computer and would list the make and model of the flow computer, along with the software version tested, on the BLM website (see § 3175.44).

§ 3175.150 – Immediate Assessments

Section 3175.150 identifies violations that are subject to immediate assessments. The BLM received several comments in response to the proposed immediate assessments in § 3175.150. The commenters stated that the immediate assessments were not necessary and duplicative in that an operator could receive an assessment and, potentially, a civil penalty for the same infraction. The commenters further stated that there was an absence of due process in that these immediate assessments were based on "non-transparent rules" and a BLM internal Inspection and Enforcement Handbook, which has not yet been developed (See discussion of Inspection and Enforcement Handbook in section II.B of this preamble – General Overview of Comments Received). The commenter suggested that the proposed rule required perfection from the operators on items that are performed a thousand times a day. A few commenters suggested breaking the immediate assessment into a major and minor category with a $1,000 assessment for major violations and $250 for minor violations.

As discussed in the preamble to the proposed rule, the immediate assessments provided for in § 3175.150 are promulgated pursuant to the Secretary of the Interior's general rulemaking authority under the MLA (30 U.S.C. 189), as well as her specific authority to stipulate remedies for the breach of lease obligations (30 U.S.C. 188(a)). See 80 FR 61646, 61680 (Oct. 13, 2015).

Some commenters argued that the immediate assessments in § 3175.150 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 oil and gas operating 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. These leases incorporate the operating regulations by reference. Thus, the immediate assessments contained in the regulations act as "liquidated damages" owed by operators who 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.

Several commenters argued that the proposed revision of § 3175.150 exceeded the BLM's statutory authority under FOGRMA insofar as the proposed revision sought to impose immediate assessments on purchasers and transporters. Upon further review and analysis of FOGRMA and other authorities, the BLM has been persuaded to remove the immediate assessments on purchasers and transporters from the final rule.

One commenter stated that operators should be provided with a 1-year phase-in period before they could be assessed for violations. The BLM agrees with this comment, but did not make any changes because the phase-in periods given in § 3175.60 also applies to immediate assessments. The shortest phase-in period is 1 year for high- and very-high-volume FMPs, which is the same phase-in period requested by the commenter.

Some commenters asked that the final rule allow for administrative review of immediate assessments. The BLM always envisioned that immediate assessments would be subject to administrative review pursuant to 43 CFR 3170.8.

The BLM sought comment on whether the immediate assessments in proposed § 3175.150 should be higher or lower and what other factors the BLM should consider in setting these assessments. (See 80 FR 61646, 61680 (Oct. 13, 2015)). The BLM noted that it proposed assessment amounts that approximate the average cost to the agency of identifying and remediating the violations. Some commenters argued that the assessments should be increased to $15,000 per violation per day—a punitive amount that would deter noncompliance. However, as liquidated damages, these assessments should not be punitive; rather, these assessments should be designed to reasonably compensate the BLM for damages associated with the violations. (See 80 FR 61646, 61680 (Oct. 13, 2015), quoting 52 FR 5384, 5387 (Feb. 20, 1987)). Because the BLM is not persuaded that the proposed assessment amounts were inappropriate, the BLM has chosen to retain the proposed assessment amounts in the final rule.

Miscellaneous changes to other BLM regulations in 43 CFR Part 3160

As noted at the beginning of the Section-by-Section discussion of this preamble, this final rule also makes changes to certain provisions of 43 CFR part 3160. Specifically, the final rule makes changes to 43 CFR 3162.7-3, 3163.1, and 3164.1. While some of these changes have already been discussed in connection with other provisions of the final rule to which they relate, each one is also explained below.

1. Consistent with the proposed rule, the final rule revises § 3162.7-3, Measurement of gas, to reflect the fact that the standards governing oil and gas measurement are now found in subpart 3175.

2. Section 3163.1, Remedies for acts of noncompliance, is being revised, consistent with the proposed rule, in several respects. As explained in connection with § 3175.150 of this final rule, the BLM's existing regulations contain provisions authorizing the BLM to impose assessments on operators and operating rights owners for violations of lease terms and conditions or any other applicable law. These assessments are a form of

liquidated damages designed to capture the costs incurred by the BLM in identifying and responding to the violations. These assessments are not intended to be punitive and are distinct from any civil penalties or other remedies that may be sought in connection with any particular violation.

The existing regulations establish two categories of assessments. There is a general category, which authorizes assessments for major and minor violations. Those assessments may be imposed only after a written notice that provides a corrective or abatement period, subject to the limitations in existing paragraph (c) of § 3163.1. As explained in the preamble to the proposed rule and with respect to § 3175.150 of the final rule, there are also currently four specific violations where the BLM's existing rules authorize the imposition of immediate assessments. Through this final rule, the BLM is modifying the approach to assessments in its regulations.

Rather than having certain specific violations be subject to immediate assessments, while major and minor violations are only subject to assessments after notice and an opportunity to cure, this final rule revises § 3163.1 so that all assessments under that section may be imposed immediately, consistent with the purpose of those assessments. As explained in the preamble to the proposed rule, the BLM believes that for these assessments, which represent liquidated damages rather than punitive fines, the notice and opportunity to cure provided for in existing regulations is unnecessary and represents an inefficient allocation of the BLM's inspection resources. The BLM's regulations governing oil and gas operations are clear and provide operators and other parties with ample notice of their obligations. The BLM incurs inspection and enforcement costs every time an operator violates one of these regulations. The assessment merely compensates the BLM for those costs. Therefore, it is unnecessary to also provide an additional corrective or abatement period before imposing the assessment.

In addition to better reflecting the purpose for which these assessments were established, this change will also result in administrative efficiencies. Under the current regulations, the BLM has to first identify a violation; then, if the violation identified is not one of the small number of violations currently subject to an immediate assessment, the BLM has to issue a notice identifying the violation and specifying a corrective period. The BLM then has to follow up and determine whether corrective actions have been taken in response to the notice before an assessment can be imposed. All of these steps cause the BLM to incur additional costs and commit additional inspection resources.

Therefore, the final rule revises paragraphs (a)(1) and (2) to allow the BLM to impose fixed assessments of $1,000 on a per-violation, per-inspection basis for major violations, and $250 on a per-violation, per-inspection basis for minor violations. The revisions to paragraphs (a)(1) and (2) maintain the BLM's discretion to impose such assessments on a case-by-case basis. The revisions are also consistent with § 3175.150 because they increase the immediate assessment for major violations to $1,000, which is appropriate given the types of violations that would be considered major. These changes do not affect § 3163.1(a)(3) through (6).

In addition to revising the approach to assessments, this final rule also revises paragraph (a) to make it apply to "any person." Under this final rule, the civil assessments under § 3163.1 are no longer limited to operating rights owners and operators. This change enables the BLM to impose assessments directly on parties who contract with operating rights owners or operators to perform activities on Federal or

Indian leases that violate applicable regulations, lease terms, notices, or orders in performing those activities, and thereby cause the agency to incur the costs to detect and remedy those violations. While the operating rights owner or operator is responsible for violations committed by contractors, and therefore is subject to assessments for the contractor's non-compliance, the contractors themselves are also obligated to comply with applicable regulations, lease terms, notices, and orders.

The authority for these immediate assessments was discussed extensively in the preamble to the proposed rule in connection with proposed changes to §§ 3163.1 and 3175.150 and is not restated here. As explained there, the immediate assessments provided for in § 3163.1 are promulgated pursuant to the Secretary's general rulemaking authority under the MLA (30 U.S.C. 189), as well as her specific authority to stipulate remedies for the breach of lease obligations (30 U.S.C. 188(a)). See 80 FR 61646, 61680 (Oct. 13, 2015).

Paragraph (b) in the current regulations identifies specific serious violations for which immediate assessments are imposed upon discovery without exception. These are: (1) Failure to install a blowout preventer or other equivalent well control equipment; (2) Drilling without approval or causing surface disturbance on Federal or Indian surface preliminary to drilling without approval; and (3) Failure to obtain approval of a plan for well abandonment prior to commencement of such operations. Since these assessments are already imposed immediately, paragraph (b)'s approach to these assessments is retained; however, the final rule does make two revisions to paragraph (b).

First, it makes paragraph (b) consistent with the revised paragraph (a) and acknowledges that certain additional immediate assessments are identified in subparts 3173, 3174, and 3175.

Second, paragraph (b) is revised to make the first two assessments found in paragraph (b) flat assessments of $1,000 on a per-violation, per-inspection basis, instead of the current framework, which contemplates an assessment of $500 per day up to a maximum cap of $5,000. As explained in connection with § 3175.150, the BLM chose the $1,000 figure because it approximates the average cost to the agency to identify such violations. Section 3163.1(b)(3) is unchanged by this final rule.

Since the final rule shifts from assessments that accrue on a daily basis to ones that can be assessed on a per-violation, per-inspection basis, the daily limitations imposed by existing paragraph (c) are no longer necessary. Therefore, the final rule deletes paragraph (c). Similarly, existing paragraph (d), which provides that continued noncompliance subjects the operating rights owner or operator to civil penalties under § 3163.2 of this subpart, is also removed because the BLM determined that it was redundant and unnecessary. Continued noncompliance may subject a party to civil penalties under § 3163.2 and the statute that it implements (Section 109 of FOGRMA, 30 U.S.C. 1719) regardless of whether the assessment regulation so provides. As a result of these specific changes, the current paragraph (e) is re-designated as paragraph (c).

As for § 3175.150, some commenters asserted that the immediate assessments identified in the proposed rule were excessive, unnecessary, and duplicative in that an operator could receive an assessment and, potentially, a civil penalty under § 3163.2 for the same infraction. Other commenters express concern that there is an absence of due process in that these immediate assessments would be based on "non-transparent rules" and a BLM Internal Inspection and Enforcement Handbook, which has not yet been developed. The commenter suggested that the proposed rule required perfection from the operators on items that are performed a thousand times a day.

The BLM does not agree with these comments. The use of immediate assessments for breaches of the oil and gas operating 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. These leases incorporate the operating regulations by reference. Thus, the immediate assessments contained in the regulations act as "liquidated damages" owed by operators who 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.

Another commenter expressed concern about the effect of this change on the BLM's workload and staffing. Still another commenter asked the BLM to provide an economic justification for the shift in approach with respect to immediate assessments and inspection and enforcement more generally. All of these concerns have already been addressed in this preamble in Section II(B) – General Overview of Comments Received.

One commenter asserted that the BLM lacks authority over contractors. The BLM does not agree with this assertion. While the operating rights owner or operator is responsible (and liable for penalties) for violations committed by contractors, the contractors are also themselves subject to the requirements of certain statutes and regulations. As a result, the BLM is revising its regulations governing both assessments and civil penalties to enable the BLM to hold contractors directly responsible for violations they commit. This change also better reflects the current practice with respect to oilfield operations.

Some commenters asked that the final rule allow for administrative review of immediate assessments. The BLM always envisioned that immediate assessments would be subject to administrative review pursuant to 43 CFR 3170.8.

Some commenters argued that the assessments should be increased to $15,000 per violation per day—a punitive amount that would deter noncompliance. However, as explained above, the purpose of these assessments is to approximate the average cost to the BLM of identifying and remediating violations. As liquidated damages, these assessments should not be punitive, but rather, should be designed to reasonably compensate the BLM for damages associated with the violations. (See 80 FR 61646, 61680 (Oct. 13, 2015), quoting 52 FR 5384, 5387 (Feb. 20, 1987)). The BLM did not make any changes in response to these comments.

3. Section 3164.1, Onshore Oil and Gas Orders, the table will be revised to remove the reference to Order 5 because this proposed rule would replace Order 5.

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 October 13, 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 and gas 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 and gas 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 with respect to Order 5, that:

- The BLM's gas measurement rules are generally outdate and do not reflect modern measurement technologies or practices;
- There were not sufficient goals/requirements related to gas sampling, BTU sampling and reporting, and orifice plate and meter tube inspections; and
- Some BLM State offices have issued their own guidance, which lacks a national perspective, creating the potential for inconsistent application of requirements.

The final rule addresses these recommendations by specifically recognizing modern industry practices and measurement technologies with respect to each of these, while also updating relevant documentation and recordkeeping requirements in order to ensure that all production is properly accounted for.

IV. Procedural Matters

Executive Order 12866 and 13563, Regulatory Planning and Review

E.O. 12866 provides that the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and Budget will review all significant rules. OIRA has determined that this final rule is not significant because it will not have an annual effect on the economy of $100 million or more and does not raise novel legal or policy issues. E.O. 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system so that it promotes predictability, reduces uncertainty, and uses the best, most innovative, and least burdensome tools for achieving regulatory ends. The E.O. 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. We have developed this rulemaking consistent with these requirements.

Regulatory Flexibility Act

The BLM certifies that this final rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.). The Small Business Administration (SBA) has developed size standards to define small entities, and those size standards can be found at 13 CFR 121.201. Small entities for crude petroleum and natural gas extraction (North American Industrial Classification System or NAICS code 211111) are defined by the SBA regulations as a business concern, including an individual proprietorship, partnership, limited liability company, or corporation, with fewer than 1,250 employees.

U.S. Census data show that in 2013, of the 6,460 domestic firms involved in crude petroleum and natural gas extraction, 99 percent (or 6,370) had fewer than 500 employees. This means that all or nearly all U.S. firms involved in crude petroleum and natural gas extraction in 2013 fell within the SBA's size standard of fewer than 1,250 employees. 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 substantial number of small entities will be affected by the final rule. Using the best available data, the BLM estimates there are approximately 3,700 lessees and operators conducting gas operations on Federal and Indian lands that could be affected by the final rule.

In addition to determining whether a substantial number of small entities are likely to be affected by this rule, the BLM must also determine whether the rule is anticipated to have a significant economic impact on those small entities. On an ongoing basis, we estimate the changes will increase the regulated community's annual costs by about $12.1 million, or an average of about $3,300 per entity per year. There will also be an estimated $6.2 million, or $1,700 per entity per year, in additional royalty payments from operators to the BLM. However, these are considered transfer payments, and are thus not included in the estimate of the final rule's net economic impact. In addition to annual costs, there will be one-time costs associated with implementing the changes of as much as $23.3 million, or an average of approximately $6,300 per entity affected by the rule. These costs are phased in over a 3-year period, at an average cost of $7.8 million per year or $2,100 per entity per year. When these annualized one-time costs are combined with annual costs, industry's average annual cost is $19.9 million per year (or $5,400 per entity per year) for the first three years following enactment of the final rule, after which it experiences just the annual burden of $12.1 million or $3,300 per entity per year. For further information on these costs estimates, please see the Economic and Threshold Analysis prepared for this final rule.

Recognizing that the SBA definition for a small business for a crude petroleum and natural gas extraction firm is one with fewer than 1,250 employees, which represents a wide range of possible oil and gas producers, the BLM, as part of the Economic and Threshold Analysis conducted for this rulemaking, looked at income data for three different small-sized entities that currently hold Federal oil and gas leases that were issued in competitive lease sales. Using annual reports that these companies filed with the

U.S. Securities and Exchange Commission for 2012, 2013, and 2014, the BLM concluded that the one-time costs and the annual ongoing costs will result in a reduction in the profit margins of these entities ranging from 0.0005 percent to 0.5742 percent, with an average reduction of 0.0362 percent. Copies of the analysis can be obtained from the contact person listed above (see **FOR FURTHER INFORMATION CONTACT)**.

All of the provisions will apply to entities regardless of size. However, entities with the greatest activity (e.g., numerous FMPs) will likely experience the greatest increase in compliance costs.

Based on the available information, we conclude that the rule will not have a significant impact on a substantial number of small entities. 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.

This final rule will update and replace the requirements of Order 5 to ensure that gas produced from Federal and Indian oil and gas leases is accurately measured and accounted for. As explained in the Economic and Threshold Analysis, the rule will increase, by about $12.1 million annually ($3,300 per entity), the cost associated with the development and production of gas resources under Federal and Indian oil and gas leases, plus an estimated $6.2 million in increased royalty payments ($1,700 per entity) to the BLM that are considered transfer payments with no net economic impact. There will also be a one-time cost estimated to be $23.3 million, phased in over a 3-year period ($6,300 per entity). For the first 3 years following enactment of the final rule, annual plus annualized one-time cost average $19.9 million per year ($5,400 per entity). After the first 3 years, the estimated burden on industry is just the estimated annual cost of $12.1 million ($3,300 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

Under the Unfunded Mandates Reform Act (2 U.S.C. 1501 et seq.), we find that:

- This final rule will not "significantly or uniquely" affect small governments. A Small Government Agency Plan is unnecessary.
- This final rule will not include any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or greater in any single year.

The final rule is not a "significant regulatory action" under the Unfunded Mandates Reform Act. The changes in this final rule will not impose any requirements on any State or local governmental entity.

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

This rule will not have significant takings implications as defined under E.O. 12630. Therefore, a takings implication assessment is not required. This rule revises the minimum standards for accurate measurement and proper reporting of gas produced from Federal and Indian leases, unit PAs, and CAs by providing an improved system for production accountability by operators and lessees. Gas production from Federal and Indian leases is subject to lease terms that expressly require that lease activities be conducted in compliance with applicable Federal laws and regulations. The implementation of this rule will not impose requirements or limitations on private property use or require dedications or exactions from owners of private property, and as such, the rule is not a governmental action capable of interfering with constitutionally protected property rights. Therefore, the rule will not cause a taking of private property or require further discussion of takings implications under this E.O.

Executive Order 13132, Federalism

Under E.O. 13132, the BLM finds that the rule will not have significant Federalism implications. A Federalism assessment is not required. This rule will not change the role of or responsibilities among Federal, State, and local governmental entities. It does not relate to the structure and role of the States and would not have direct or substantive 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 will affect Indian tribes. In conformance with the Secretary's policy on tribal consultation, the BLM invited more than 175 tribal entities to tribal consultation meetings both before the rule was proposed and during the public comment period on the proposed rule. The consultations were held in both pre-publication and post-publication:

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, D.C. 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 as 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 addition, some tribes expressed concern about the cost of performing detailed meter tube inspections, the proposed requirement for the location of the sample probe because it would be contrary to API specification, the requirement to report a dry heating value when water vapor is known to be present, and the cost and benefit of requiring sample cylinders to be sealed after they are cleaned. 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 only. That said, the BLM will continue to consult with tribes on measurement issues that impact them and their resources. The BLM did make changes to the rule based on these and other comments received by industry. In response to the concern over the cost of performing detailed meter tube inspections, the BLM eliminated the requirement to perform routine detailed meter-tube inspections; these inspections will now only be triggered by a basic inspection that reveals the need to perform a detailed inspection. In addition, the detailed inspection will only be required on high- and very-high-volume FMPs under the final rule. The final rule also re-defined the thresholds separating low-, high-, and very-high-volume FMPs, which reduced the estimated percentage of high- and very-high-volume FMPs subject to detailed inspections from 22 percent under the proposed rule to 11 percent under the final rule.

In response to concerns expressed over the proposed requirement for the location of the sample probe, the BLM eliminated the proposed requirement and reverted to placing the sample probe as required by API standards. The BLM did not make any changes to the requirement in the proposed rule to report heating value on a dry basis because industry did not submit any data that would justify an alternative. On the contrary, the data that the BLM did receive indicated that the assumption of water vapor saturation as the basis for heating value, suggested by one tribal member, would result in under reporting of heating value. In response to concerns over the costs and benefits of the proposed requirement to seal sample cylinders after cleaning, the BLM determined that it was not a feasible requirement and deleted it in the final rule.

Executive Order 12988, Civil Justice Reform

Under E.O. 12988, we have determined that the rule will not unduly burden the judicial system and meets the requirements of Sections 3(a) and 3(b)(2) of the Order. We have reviewed the rule to eliminate drafting errors and ambiguity. It has been written to 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 rule will not impede facilitating cooperative conservation and takes appropriate account of the interests of persons with ownership or other legally recognized interests in land or other natural resources. The rulemaking process involved Federal, State, local and tribal governments, private for-profit and nonprofit institutions, other nongovernmental entities and individuals in the decision-making via the public comment process for the rule. The process ensured that the programs, projects, and activities are consistent with protecting public health and safety.

Paperwork Reduction Act

Overview

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. The PRA and OMB regulations (see 5 CFR 1320.3(c) and (k)) provide that collections of information include requests and requirements that an individual, partnership, or corporation obtain information, and report it to a Federal agency.

This final 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 1004-0210.

Summary

Title: Measurement of Gas.

Forms: None.

OMB Control Number: 1004-0210.

Description of Respondents: Holders of Federal and Indian (except Osage Tribe) oil and gas leases, operators, purchasers, transporters, any other person directly involved in producing, transporting, purchasing, or selling, including measuring, oil or gas through the point of royalty measurement or the point of first sale, and manufacturers of equipment or software used in measuring natural gas.

Abstract: This rule updates the BLM's regulations pertaining to gas measurement, taking into account changes in the gas industry's measurement technologies and standards. The information collection activities in this rule will assist the BLM in ensuring the accurate measurement and proper reporting of all gas removed or sold from Federal and Indian (except Osage Tribe) leases, units, unit participating areas, and areas subject to communitization agreements, by providing a system for production accountability by operators, lessees, purchasers, and transporters.

Frequency of Collection: On occasion, except for 43 CFR 3175.115 and 3175.120, which require submission of gas analysis reports at frequencies that vary from monthly to annually.

Obligation to Respond: Required to obtain or retain benefits.

Estimated Annual and Annualized Responses: 276,797.

Estimated Reporting and Recordkeeping “Hour” Burden: 77,950 hours.

Estimated Non-Hour Cost: $21,194,881in annual non-hour burdens for the first 3 years following the effective date of the final rule, and $19,495,765 in annual non-hour burdens after that.

Discussion of Information Collection Activities

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

Some of these information collection activities are usual and customary because they are required by gas sales contracts and/or industry standards. To the extent they are usual and customary, they are not “burdens” under the PRA (see 5 CFR 1320.3(b)(2)). To the extent these regulations increase the frequency of data gathering beyond what is usual and customary, or require more information than is usual and customary, the incremental burdens are included in the burdens disclosed here.

Where these regulations require operators to maintain records and submit information at the request of the BLM (usually during production audits), the burdens of disclosure to the respondent and to the Federal Government are included in the estimated burdens for "Required Recordkeeping and Records Submission" for 43 CFR 3170.7, a regulation that is part of the rulemaking for site security (RIN 1004-AE15, control no. 1004-0207). The recordkeeping burdens are included among the information collection activities for this rule.

The information collection activities in this rule can be organized in the following categories:

A. Testing of Makes and Models of Gas-Measurement Equipment;

B. Inspection and Verification; and

C. Determining and Reporting Volumes, Heating Value, and Relative Density

Each category is discussed below.

A. <u>Testing of Makes and Models of Gas-Measurement Equipment or Software</u>

Some provisions in the final rule provide for the listing of approved makes and models of gas-measurement equipment or software at www.blm.gov. They also provide for procedures that operators or manufacturers may use to seek approval of other makes and models. The operator or manufacturer arranges for testing of the equipment or software by a qualified testing facility. The testing is accomplished by comparing the requested equipment or software with reference standards specified in the regulations. Next, the operator or manufacturer submits a report to the BLM's PMT. The PMT, which consists of BLM employees who are experts in oil and gas measurement, acts as a central advisory body for reviewing and approving devices and software not specifically addressed and approved in these regulations. The report must show the results of the testing, as well as descriptions of the test set-up and procedures, qualifications of the test facility, and uncertainty analyses.

The PMT reviews the report, and then recommends that use of the device or software be approved, disapproved, or approved with conditions. Approval or approval with conditions by the PMT is a pre-requisite for BLM approval of a device or software that is not included on a list of approved makes and models in the regulations. These information collection activities assist the BLM in ensuring that the equipment and software used in gas measurement are in compliance with the relevant performance standards.

We estimate that a limited number of respondents will choose to seek approval of makes and models of equipment or software, and the frequency of such requests will be limited. For the most part, we anticipate one-time, start-up requests during the first 3 years after the effective date of the rule. We calculated cumulative burden estimates for these activities for the first 3 years after the effective date of the rule. We annualized these burden estimates for inclusion in the total estimated hour burdens of this rule.

Most of these procedures begin when the operator or manufacturer arranges for testing of the equipment or software by a qualified testing facility. Because the qualified testing facility will generally be a contractor, and not employees of a respondent, we estimated non-hour burdens for those procedures. The exception is the procedure for requesting approval of makes and models of transducers that are used before the effective date of this rule. For those makes and models, the final rule allows operators or manufacturers to submit existing test data in lieu of arranging for testing by a qualified testing facility. We estimate no non-hour burdens in those circumstances.

The information collection activities within this category are:

1. Transducers — Test Data Collection and Submission for Existing Makes and Models (43 CFR 3175.43 and 3175.130);
2. Transducers — Test Data Collection and Submission for Future Makes and Models (43 CFR 3175.43 and 3175.130);
3. Flow-Computer Software — Test Data Collection and Submission for Existing Makes and Models (43 CFR 3175.44 and 3175.140);
4. Flow-Computer Software — Test Data Collection and Submission for Future Makes and Models (43 CFR 3175.44 and 3175.140);
5. Isolating Flow Conditioners — Test Data Collection and Submission for Existing Makes and Models (43 CFR 3175.46);
6. Differential Primary Devices Other than Flange-Tapped Orifice Plates — Test Data Collection and Submission for Existing Makes and Models (43 CFR 3175.47);
7. Linear Measurement Devices — Test Data Collection and Submission for Existing Makes and Models (43 CFR 3175.48);
8. Linear Measurement Devices — Test Data Collection and Submission for Future Makes and Models (43 CFR 3175.48);

9. Accounting Systems — Test Data Collection and submission for Existing Makes and Models (43 CFR 3175.49); and
10. Accounting Systems — Test Data Collection and submission for Future Makes and Models (43 CFR 3175.49).

B. Inspection and Verification

Inspection and verification activities assist the BLM in ensuring that the equipment used to measure gas is in good working order. The information that is required in each "inspection" depends on what type of equipment must be examined. The information that is required in each "verification" is in accordance with the definition of that term at 43 CFR 3175.10(a): "The amount of error in a differential pressure, static pressure, or temperature transducer or element by comparing the readings of the transducer or element with the readings from a certified test device with known accuracy."

Virtually all gas contracts and industry standards require periodic removal and inspection of equipment that is used to measure and analyze the content of natural gas. To the extent these regulations increase the frequency of inspection beyond what is usual and customary, or require more information than is usual and customary, the incremental burdens are disclosed here. Where these regulations require operators to submit information at the request of the BLM (usually during production audits), the burdens to the respondent and to the Federal Government are included in the estimated burdens for "Required Recordkeeping and Records Submission" for 43 CFR 3170.7, a regulation that is part of the rulemaking for site security (RIN 1004-AE15, control no. 1004-0207).

The information collection activities within this category are:

1. Schedule of Basic Meter Tube Inspection (43 CFR 3175.80(h)(3));

2. Basic Inspection of Meter Tubes — Data Collection and Submission (43 CFR 3175.80(h)(5));
3. Detailed Inspection of Meter Tubes — Data Collection and Submission (43 CFR 3175.80(i) and (j));
4. Request for Extension of Time for a Detailed Meter Tube Inspection (43 CFR 1375.80(i));
5. Redundancy Verification Check for Electronic Gas Measurement Systems (43 CFR 3175.102(e)(2));
6. Notification of Verification (43 CFR 3175.92(e) and 3175.102(f));
7. Sample Cylinder Cleaning — Documentation (43 CFR 3175.113(c)(3));
8. Sample Separator Cleaning — Documentation (43 3175.113(d)(1));
9. Evacuation and Pre-charge for the Helium Pop Method — Documentation (43 CFR 3175.114(a)(2));
10. O-ring and Lubricant Composition for the Floating Piston Method — Documentation (43 CFR 3175.114(a)(3));
11. Schedule for Spot Sampling (43 CFR 3175.113(b));
12. Submission of On-line Gas Chromatograph Specifications (43 CFR 3175.117(c)); and
13. Gas Chromatograph Verification — Documentation (43 CFR 3175.118(d)).

C. Determining and Reporting Volumes, Heating Value, and Relative Density

Natural gas consists mainly of methane and also includes varying amounts of other hydrocarbons, nitrogen, and carbon dioxide. These regulations assist in determining what components are in samples of natural gas, and in what percentages. They also assist in determining the volumes of natural gas produced. These measurements are necessary for calculating royalties accurately.

The information collection activities within this category are:

1. Quantity Transaction Record (43 CFR 3175.104(a));
2. Configuration Log (43 CFR 3175.104(b)); and
3. Gas Analysis Report – Entry into Gas Analysis Reporting and Verification System (43 CFR 3175.120(f)).

Burden Estimates

The BLM estimates 276,797 responses, 77,950 hours, and $5,030,088 hour burdens annually for industry for the first three years after the rule is enacted and 276,720 responses, 76,340 hours, and $4,926,201 hour burdens annually for industry after that. These estimates include both annual estimates of recurring burdens and one-time burdens for initial implementation of the rule. The one-time burdens are shown as the average of the total burdens divided by three (i.e., spread over the next three years).

The burdens to respondents include time spent for compiling and preparing information. The frequency of response for each of the information collections is "on occasion," with the exception of 43 CFR 3175.120, which requires submission of gas analysis reports to the BLM within 15 days following due dates for spot samples as specified in § 3175.115:

- Gas spot samples at very-low-volume FMPs are required at least annually;
- Gas samples at low-volume FMPs are required at least every 6 months, and

- Spot samples at high- and very-high-volume FMPs are required at least every 3 months and every month, respectively, unless the BLM determines that more frequent analysis is required under § 3175.115(c).

The following table itemizes the hour burdens.

A. **Type of Response**	**B.** **Number of Responses**	**C.** **Hours Per Response**	**D.** **Total Hours**
Transducers – Test Data Collection and Submission for Existing Makes and Models 43 CFR 3175.43 and 3175.130 One-Time	100	15.5	1,550
Transducers – Test Data Collection and Submission for Future Makes and Models 43 CFR 3175.43 and 3175.130 Annual	1	15.5	15.5
Flow-Computer Software – Test Data Collection and Submission for Existing Makes and Models 43 CFR 3175.44 and 3175.140 One-Time	100	8.0	800.0
Flow-Computer Software – Test Data Collection and Submission for Future Makes and Models 43 CFR 3175.44 and 3175.140 Annual	20	8.0	160.0
Isolating Flow Conditioners — Test Data Collection and Submission for Existing Makes and Models 43 CFR 3175.46 One-Time	3	80.0	240.0
Differential Primary Devices Other than Flange-Tapped Orifice Plates – Test Data Collection and Submission for Existing Makes and Models 43 CFR 3175.47 One-Time	3	80.0	240.0
Linear Measurement Devices– Test Data Collection and Submission for Existing Makes and Models 43 CFR 3175.48 One-Time	5	80.0	400.0

A. Type of Response	B. Number of Responses	C. Hours Per Response	D. Total Hours
Linear Measurement Devices – Test Data Collection and Submission for Future Makes and Models 43 CFR 3175.48 Annual	1	80.0	80.0
Accounting Systems — Test Data Collection and Submission for Existing Makes and Models 43 CFR 3175.49 One-Time	20	80.0	1,600.0
Accounting Systems – Test Data Collection and Submission for Future Makes and Models 43 CFR 3175.49 Annual	2	80.0	160.0
Schedule of Basic Meter Tube Inspection 43 CFR 3175.80(h)(3) Annual	936	8.0	7,488.0
Basic Inspection of Meter Tubes – Data Collection and Submission 43 CFR 3175.80(h)(5) Annual	9,358	0.1	935.8
Detailed Inspection of Meter Tubes – Data Collection and Submission 43 CFR 3175.80(i) and (j) Annual	4,464	0.5	2,232.0
Request for Extension of Time for a Detailed Meter Tube Inspection 43 CFR 3175.80(i) Annual	1,116	0.5	558.0
Redundancy Verification Check for Electronic Gas Measurement Systems 43 CFR 3175.102(e)(2) Annual	1,000	0.5	500.0
Notification of Verification 3175.92(e) and 3175.102(f)) Annual	1,172	1.0	1,172.0
Sample Cylinder Cleaning – Documentation 43 CFR 3175.113(c)(3) Annual	75,731	0.1	7,573.1

A. Type of Response	B. Number of Responses	C. Hours Per Response	D. Total Hours
Sample Separator Cleaning – Documentation 43 CFR 3175.113(d)(1) Annual	7,573	0.1	757.3
Evacuation and Pre-charge for the Helium Pop Method – Documentation 43 CFR 3175.114(a)(2) Annual	7,573	0.1	757.3
O-ring and Lubricant Composition for the Floating Piston Method — Documentation 43 CFR 3175.114(a)(3) Annual	3,787	0.1	378.7
Schedule for Spot Sampling 43 CFR 3175.113(b) Annual	1,514	1.0	1,514.0
Submission of On-line Gas Chromatograph Specifications 43 CFR 3175.117(c) Annual	20	1.0	20.0
Quantity Transaction Record – Data Collection and Submission 43 CFR 3175.104(a) Annual	3,185	0.5	1,592.5
Configuration Log – Data Collection and Submission 43 CFR 3175.104(b) Annual	3,185	0.5	1,592.5
Gas Chromatograph Verification – Documentation 43 CFR 3175.118(d) Annual	2,461	0.5	1,230.5
Gas Analysis Report – Entry into Gas Analysis Reporting and Verification System 43 CFR 3175.120(f) Annual	153,621	0.3	47,622.5
Annual **One-time**	276,720 231		76,340 4,830
One-Time, Annualized* **Total, Annualized****	77 276,797		1,610 77,950

National Environmental Policy Act

The BLM prepared an environmental assessment (EA), a Finding of No Significant Impact (FONSI), and a Decision Record (DR) that concludes that the final rule will not constitute a major Federal action significantly affecting the quality of the human environment under Section 102(2)(C) of the National Environmental Policy Act (NEPA), 42 U.S.C. 4332(2)(C). Therefore, a detailed statement under NEPA is not required. Copies of the EA, FONSI, and DR are available for review and on file in the BLM Administrative Record at the address specified in the **ADDRESSES** section.

As explained in the EA, FONSI, and DR, the final rule will 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 final rule clarifies the acceptable methods for estimating and documenting reported volumes of gas when metering equipment is malfunctioning or out of service. The final rule also establishes new requirements for gas sampling, including sampling location and methods, sampling frequency, analysis methods, and the minimum number of components to be analyzed. Similarly, the final rule establishes new meter equipment, maintenance, inspection, and reporting standards. These changes will enhance the agency's ability to account for the gas produced from Federal and Indian lands, but should have minimal to no impact on the environment.

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 the impacts of three separate rulemakings, stating CEQ regulations that require connected actions to be evaluated in a single document. These commenters suggested that the BLM should prepare a single EIS to address all three rules.

The BLM did not make any changes in response to these comments. CEQ's NEPA regulations at 40 CFR 1508.18 do identify new or revised agency rules and regulations as an example of a Federal action, but new agency regulations that are procedural or administrative in nature are categorically excluded from NEPA review pursuant to 43 CFR 46.210(i). Nevertheless the BLM chose to complete an EA for the rule, to assess the potential environmental impacts of the few provisions that could result in on-the-ground changes to measurement facilities. As noted in the EA, the BLM concludes that those few provisions will not have a significant impact on the environment.

With respect to whether the three rulemakings to replace BLM’s existing Onshore Orders 3, 4, and 5 are connected actions for purposes of NEPA, the BLM does not agree with the commenter’s suggestion. While the BLM acknowledges that the rules are related and have been designed to work together, each rule is an independent and freestanding effort; none of the rules automatically triggers other actions that may impact the environment; none of the rules requires for its implementation that other actions be taken previously or simultaneously; and none depends on a larger action for its justification. Thus, the BLM reasonably decided to go forward with three EAs rather than a single overarching EIS.

With respect to economic impacts, the BLM has determined that the economic analysis referred to in this preamble and in the EA prepared for this rule adequately discloses that the rule will increase costs to operator, but that those increased costs will be small compared to the costs of operating an oil and gas well. Therefore, the BLM did not make any changes in response to that comments.

Other commenters stated the BLM did not adequately address potential surface impacts to private land, did not minimize surface impacts, did not address a reasonable range of alternatives, and did not adequately describe the Affected Environment. The BLM did not make any changes in response to these comments. The BLM anticipates that in the majority of cases, operators will use existing surface disturbances to come into compliance with the final rule, such as using existing well pad locations. Use of existing disturbance will minimize new surface construction and surface impacts. Since any new facilities will likely be constructed, relocated, or retrofitted on lease at an existing facility, the likelihood that the regulations will result in new impacts to private surface is low. In the rare instance new pipelines or other facilities prove to be necessary on private surface, BLM authorization for activities on split estate will include site-specific NEPA documentation, with appropriate project-level mitigation and best management practices. In short, surface disturbance on private lands is likely to be minimal, and any attempt to estimate these impacts at this time would be speculative.

Finally, commenters asserted that BLM did not satisfy its obligation under NEPA 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 are anticipated to be minimal. The EA, FONSI, and DR were updated to address these comments, but the revisions 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

This final rule will not have a significant adverse effect on the nation's energy supply, distribution or use, including a shortfall in supply or price increase. Changes in this final rule will strengthen the BLM's accountability requirements for operators under Federal and Indian oil and gas leases. As discussed above, these changes will prescribe specific requirements for production measurement, including sampling, measuring, and analysis protocol; categories of violations; and reporting requirements. The final rule also establishes specific requirements related to the physical makeup of meter components. All of the changes will increase the regulated community's annual costs by about $19.9 million in annual and annualized one-time costs (or $5,400 per entity per year) for the first 3 years after the final rule is enacted, and then $12.1 million, or an average of approximately $3,300 per entity per year after that plus an additional $6.2 million in royalty payments from industry to the BLM that are considered a transfer payment and thus not a net economic impact. Entities with the greatest activity (e.g., numerous FMPs) will incur higher costs. Additional information on these costs estimates can be found in the Economic and Threshold Analysis prepared for this final rule.

We expect that the final rule will not result in a net change in the quantity of oil and gas that is produced from oil and gas leases on Federal and Indian lands.

Information Quality Act

In developing this rule, we did not conduct or use a study, experiment, or survey requiring peer review under the Information Quality Act (Pub. L. No. 106-554, Appendix C Title IV, Section 515, 114 Stat. 2763A–153).

Authors

The principal authors of this rule are Richard Estabrook, Petroleum Engineer, BLM Washington Office; Rodney Brashear, Petroleum Engineer Technician, BLM Tres Rios Field Office; Jim Hutchinson, Assistant Field Manager, BLM Newcastle Field Office; Jeff Jette, Petroleum Engineering Technician, BLM Buffalo Field Office; Clifford Johnson of the BLM Vernal Field Office; Gary Roth, Petroleum Engineering Technician, BLM Buffalo Field Office; and Noell Sturdevant, I&E Coordinator, BLM New Mexico State Office. The team was assisted by Michael Wade, BLM Washington Office; Faith Bremner, Jean Sonneman, Joe Berry 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; John Barder, ONRR Denver Officer; Dylan Fuge, Counselor to the Director, BLM; Christopher Rhymes, Attorney Advisor, Office of the Solicitor, Department of the Interior; and Wanda Weatherford (formerly with BLM) 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 exploration, Oil and gas measurement, Penalties; 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 is revised 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 § 3162.7-3 to read as follows:

§ 3162.7-3 Measurement of gas.

All gas removed or sold from a lease, communitized area, or unit participating area must be measured under subpart 3175 of this chapter. All measurement must be on the lease, communitized area, or unit from which the gas originated and must not be commingled with gas originating from other sources unless approved by the authorized officer under subpart 3173 of this chapter.

3. Amend § 3163.1 by revising paragraphs (a) introductory text, (a)(1) and (2), (b) introductory text, (b)(1) and (2), removing paragraphs (c) and (d), redesignating paragraph (e) as paragraph (c), and revising newly redesignated paragraph (c) to read as follows:

§ 3163.1 Remedies for acts of noncompliance.

(a) Whenever any person fails or refuses to comply with the regulations in this part, the terms of any lease or permit, or the requirements of any notice or order, the authorized officer shall notify that person in writing of the violation or default.

(1) For major violations, the authorized officer may also subject the person to an assessment of $1,000 per violation, per inspection.

(2) For minor violations, the authorized officer may also subject the person to an assessment of $250 per violation, per inspection.

* * * * *

(b) Certain instances of noncompliance are violations of such a nature as to warrant the imposition of immediate major assessments upon discovery, as compared to those established by paragraph (a) of this section. Upon discovery the following violations, as well as the violations identified in subparts 3173, 3174, and 3175 of this chapter, will result in assessments in the specified amounts per violation, per inspection, without exception:

(1) For failure to install blowout preventer or other equivalent well control equipment, as required by the approved drilling plan, $1,000;

(2) For drilling without approval or for causing surface disturbance on Federal or Indian surface preliminary to drilling without approval, $1,000;

* * * * *

(c) On a case-by-case basis, the State Director may compromise or reduce assessments under this section. In compromising or reducing the amount of the assessment, the State Director will state in the record the reasons for such determination.

§ 3164.1 [Amended]

4. Amend § 3164.1, in paragraph (b), by removing the fifth entry in the chart.

PART 3170 – ONSHORE OIL AND GAS PRODUCTION

5. 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.

6. Add subpart 3175 to part 3170 to read as follows:

Subpart 3175 – Measurement of Gas

Sec.

§ 3175.10 Definitions and acronyms.

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

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

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

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

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

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

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

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

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

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

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

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

Configuration log means a list of all fixed or user-programmable parameters used by the flow computer that could affect the calculation or verification of flow rate, volume, or heating value.

Discharge coefficient means an empirically derived correction factor that is applied to the theoretical differential flow equation in order to calculate a flow rate that is within stated uncertainty limits.

Effective date of a spot or composite gas sample means the first day on which the relative density and heating value determined from the sample are used in calculating the volume and quality on which royalty is based.

Electronic gas measurement (EGM) means all of the hardware and software necessary to convert the static pressure, differential pressure, and flowing temperature developed as part of a primary device, to a quantity, rate, or quality measurement that is used to determine Federal royalty. For orifice meters, this includes the differential-pressure transducer, static-pressure transducer, flowing-temperature transducer, on-line gas chromatograph (if used), flow computer, display, memory, and any internal or external processes used to edit and present the data or values measured.

Element range means the difference between the minimum and maximum value that the element (differential-pressure bellows, static-pressure element, and temperature element) of a mechanical recorder is designed to measure.

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.

GPA (followed by a number) means a standard prescribed by the Gas Processors Association, with the number referring to the specific standard.

Heating value means the gross heat energy released by the complete combustion of one standard cubic foot of gas at 14.73 pounds per square inch absolute (psia) and 60° F.

Heating value variability means the deviation of previous heating values over a given time period from the average heating value over that same time period, calculated at a 95 percent confidence level. Unless otherwise approved by the BLM, variability is determined with the following equation:

$$V_{95\%} = 100 \times \frac{\sigma_{HV} \times 2.776}{\overline{HV}}$$

Where:

$V_{95\%}$ = heating value variability, %

σ_{HV} = standard deviation of the previous 5 heating values

2.776 = the "student-t" function for a probability of 0.05 and 4 degrees of freedom (degree of freedom is the number of samples minus 1)

$\overline{HV}$ = the average heating value over the time period used to determine the standard deviation

High-volume facility measurement point or high-volume FMP means any FMP that measures more than 200 Mcf/day, but less than or equal to 1,000 Mcf/day over the averaging period.

Hydrocarbon dew point means the temperature at which hydrocarbon liquids begin to form within a gas mixture. For the purpose of this regulation, the hydrocarbon dew point is the flowing temperature of the gas measured at the FMP, unless otherwise approved by the AO.

Integration means a process by which the lines on a circular chart (differential pressure, static pressure, and flowing temperature) used in conjunction with a mechanical chart recorder are re-traced or interpreted in order to determine the volume that is represented by the area under the lines. An integration statement documents the values determined from the integration.

Live input variable means a datum that is automatically obtained in real time by an EGM system.

Low-volume facility measurement point or low-volume FMP means any FMP that measures more than 35 Mcf/day, but less than or equal to 200 Mcf/day, over the averaging period.

Lower calibrated limit means the minimum engineering value for which a transducer was calibrated by certified equipment, either in the factory or in the field.

Mean means the sum of all the values in a data set divided by the number of values in the data set.

Mole percent means the number of molecules of a particular type that are present in a gas mixture divided by the total number of molecules in the gas mixture, expressed as a percentage.

Normal flowing point means the differential pressure, static pressure, and flowing temperature at which an FMP normally operates when gas is flowing through it.

Primary device means the volume-measurement equipment installed in a pipeline that creates a measureable and predictable pressure drop in response to the flow rate of fluid through the pipeline. It includes the pressure-drop device, device holder, pressure taps, required lengths of pipe upstream and downstream of the pressure-drop device, and any flow conditioners that may be used to establish a fully developed symmetrical flow profile.

Qualified test facility means a facility with currently certified measurement systems for mass, length, time, temperature, and pressure traceable to the NIST primary standards or applicable international standards approved by the BLM.

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

Reynolds number means the ratio of the inertial forces to the viscous forces of the fluid flow, and is defined as:

$$R_e = \frac{V\rho D}{\mu}$$

Where:

R_e = the Reynolds number
V = velocity
ρ = fluid density
D = inside meter tube diameter
μ = fluid viscosity

Redundancy verification means a process of verifying the accuracy of an EGM system by comparing the readings of two sets of transducers placed on the same primary device.

Secondary device means the differential-pressure, static-pressure, and temperature transducers in an EGM system, or a mechanical recorder, including the differential pressure, static pressure, and temperature elements, and the clock, pens, pen linkages, and circular chart.

Self-contained EGM system means an EGM system in which the transducers and flow computer are identified by a single make and model number from which the performance specifications for the transducers and flow computer are obtained. Any change to the make or model numbers of either a transducer or a flow computer within a self-contained EGM system changes the system to a component-type EGM system.

Senior fitting means a type of orifice plate holder that allows the orifice plate to be removed, inspected, and replaced without isolating and depressurizing the meter tube.

Standard cubic foot (scf) means a cubic foot of gas at 14.73 psia and 60° F.

Standard deviation means a measure of the variation in a distribution, and is equal to the square root of the arithmetic mean of the squares of the deviations of each value in the distribution from the arithmetic mean of the distribution.

Tertiary device means, for EGM systems, the flow computer and associated memory, calculation, and display functions.

Threshold of significance means the maximum difference between two data sets (a and b) that can be attributed to uncertainty effects. The threshold of significance is determined as follows:

$$T_s = \sqrt{U_a^2 + U_b^2}$$

Where:

T_s = Threshold of significance, in percent
U_a = Uncertainty (95 percent confidence) of data set a, in percent
U_b = Uncertainty (95 percent confidence) of data set b, in percent

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.

Turndown means a reduction of the measurement range of a transducer in order to improve measurement accuracy at the lower end of its scale. It is typically expressed as the ratio of the upper range limit to the upper calibrated limit.

Type test means a test on a representative number of a specific make, model, and range of a device to determine its performance over a range of operating conditions.

Uncertainty means the range of error that could occur between a measured value and the true value being measured, calculated at a 95 percent confidence level.

Upper calibrated limit means the maximum engineering value for which a transducer was calibrated by certified equipment, either in the factory or in the field.

Upper range limit (URL) means the maximum value that a transducer is designed to measure.

Verification means the process of determining the amount of error in a differential pressure, static pressure, or temperature transducer or element by comparing the readings of the transducer or element with the readings from a certified test device with known accuracy.

Very-low-volume facility measurement point or very-low-volume FMP means any FMP that measures 35 Mcf/day or less over the averaging period.

Very-high-volume facility measurement point or very-high-volume FMP means any FMP that measures more than 1,000 Mcf/day over the averaging period.

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

GARVS means the BLM's Gas Analysis Reporting and Verification System.

GC means gas chromatograph.

GPA means the Gas Processors Association.

Mcf means 1,000 standard cubic feet.

psia means pounds per square inch – absolute.

psig means pounds per square inch – gauge.

§ 3175.20 General requirements.

Measurement of all gas at an FMP must comply with the standards prescribed in this subpart, except as otherwise approved under § 3170.6 of this part.

§ 3175.30 Incorporation by reference.

(a) Certain material identified 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; and 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 Gas Association (AGA), 400 North Capitol Street, NW, Suite 450, Washington, DC 20001; telephone 202-824-7000.

(1) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Second Edition, September, 1985 (“AGA Report No. 3 (1985)”), IBR approved for §§ 3175.61(a) and (b), 3175.80(k), and 3175.94(a).

(2) AGA Transmission Measurement Committee Report No. 8, Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases; Second Edition, November 1992 (“AGA Report No. 8”), IBR approved for §§ 3175.103(a) and 3175.120(d).

(c) 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 14—Natural Gas Fluids Measurement, Section 1, Collecting and Handling of Natural Gas Samples for Custody Transfer; Seventh Edition, May 2016 (“API 14.1”), IBR approved for §§ 3175.112(b) and (c), 3175.113(c), and 3175.114(b).

(2) 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 § 3175.31(a) and Table 1 to § 3175.80.

(3) API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 2, Specification and Installation Requirements; Fifth Edition, March 2016 (“API 14.3.2”), IBR approved for §§ 3175.46(b) and (c), 3175.61(a), 3175.80(c) through (g) and (i) through (l), and Table 1 to § 3175.80.

(4) API MPMS Chapter 14, Section 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters, Part 3, Natural

Gas Applications; Fourth Edition, November 2013 (“API 14.3.3”), IBR approved for §§ 3175.94(a) and 3175.103(a).

(5) API MPMS Chapter 14, Natural Gas Fluids Measurement, Section 3, Concentric, Square-Edged Orifice Meters, Part 3, Natural Gas Applications, Third Edition, August, 1992 (“API 14.3.3 (1992)”), IBR approved for § 3175.61(b).

(6) API MPMS, Chapter 14, Section 5, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer; Third Edition, January 2009; Reaffirmed February 2014 (“API 14.5”), IBR approved for §§ 3175.120(c) and 3175.125(a).

(7) API MPMS Chapter 21, Section 1, Flow Measurement Using Electronic Metering Systems--Electronic Gas Measurement; Second Edition, February 2013 (“API 21.1”), IBR approved for Table 1 to § 3175.100, §§ 3175.101(e), 3175.102(a) and (c) through (e), 3175.103(b) and (c), and 3175.104(a) through (d).

(8) API MPMS Chapter 22—Testing Protocol, Section 2, Differential Pressure Flow Measurement Devices; First Edition, August 2005; Reaffirmed August 2012 (“API 22.2”), IBR approved for § 3175.47(b) through (d).

(d) Gas Processors Association (GPA), 6526 E. 60th Street, Tulsa, OK 74145; telephone 918-493-3872.

(1) GPA Standard 2166-05, Obtaining Natural Gas Samples for Analysis by Gas Chromatography Revised 2005 (“GPA 2166-05”), IBR approved for §§ 3175.113(c) and (d), 3175.114(a), and 3175.117(a).

(2) GPA Standard 2261-13, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography; Revised 2013 ("GPA 2261-13"), IBR approved for § 3175.118(a) and (c).

(3) GPA Standard 2198-03, Selection, Preparation, Validation, Care and Storage of Natural Gas and Natural Gas Liquids Reference Standard Blends; Revised 2003 ("GPA 2198-03"), IBR approved for § 3175.118(c).

(4) GPA Standard 2286-14, Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography; Revised 2014 ("GPA 2286-14"), IBR approved for § 3175.118(e).

(e) Pipeline Research Council International (PRCI), 3141 Fairview Park Dr., Suite 525, Falls Church, VA 22042; telephone 703-205-1600.

(1) PRCI Contract-NX-19, Manual for the Determination of Supercompressibility Factors for Natural Gas; December 1962 ("PRCI NX 19"), IBR approved for §3175.61(b).

(2) [Reserved]

Note to paragraphs (b) through (e): 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 Ave., Paramus, NJ 07652; telephone 201-986-1131; http://infostore.saiglobal.com/store/.

§ 3175.31 Specific performance requirements.

(a) Flow rate measurement uncertainty levels. (1) For high-volume FMPs, the measuring equipment must achieve an overall flow rate measurement uncertainty within ±3 percent.

(2) For very-high-volume FMPs, the measuring equipment must achieve an overall flow rate measurement uncertainty within ±2 percent.

(3) The determination of uncertainty is based on the values of flowing parameters (e.g., differential pressure, static pressure, and flowing temperature for differential meters or velocity, mass flow rate, or volumetric flow rate for linear meters) determined as follows, listed in order of priority:

(i) The average flowing parameters listed on the most recent daily QTR, if available to the BLM at the time of uncertainty determination; or

(ii) The average flowing parameters from the previous day, as required under § 3175.101(b)(4)(i) through (iii) (for differential meters).

(4) The uncertainty must be calculated under API 14.3.1, Section 12 (incorporated by reference, see § 3175.30) or other methods approved by the AO.

(b) Heating value uncertainty levels. (1) For high-volume FMPs, the measuring equipment must achieve an annual average heating value uncertainty within ±2 percent.

(2) For very-high-volume FMPs, the measuring equipment must achieve an annual average heating value uncertainty within ±1 percent.

(3) Unless otherwise approved by the AO, the average annual heating value uncertainty must be determined as follows:

$$U_{\overline{HV}} = 0.951 \times V_{95\%}\sqrt{\frac{1}{N}}$$

Where:

$U_{\overline{HV}}$ = average annual heating value uncertainty

$V_{95\%}$ = heating value variability

N = the number of samples taken per year (N = 1, 2, 4, 6, 12, or 26)

(c) Bias. For low-volume, high-volume, and very-high-volume FMPs, the measuring equipment used for either flow rate or heating value determination must achieve measurement without statistically significant bias.

(d) Verifiability. An operator may not use measurement equipment for which the accuracy and validity of any input, factor, or equation used by the measuring equipment to determine quantity, rate, or heating value are not independently verifiable by the BLM. Verifiability includes the ability to independently recalculate the volume, rate, and heating value based on source records and field observations.

§ 3175.40 Measurement equipment approved by standard or make and model.

The measurement equipment described in §§ 3175.41 through 3175.49 is approved for use at FMPs under the conditions and circumstances stated in those sections, provided it meets or exceeds the minimum standards prescribed in this subpart.

§ 3175.41 Flange-tapped orifice plates.

Flange-tapped orifice plates that are constructed, installed, operated, and maintained in accordance with the standards in § 3175.80 are approved for use.

§ 3175.42 Chart recorders.

Chart recorders used in conjunction with approved differential-type meters that are installed, operated, and maintained in accordance with the standards in § 3175.90 are approved for use for low-volume and very-low-volume FMPs only, and are not approved for high-volume or very-high-volume FMPs.

§ 3175.43 Transducers.

(a) A transducer of a specific make, model, and URL is approved for use in conjunction with differential meters for high-volume or very-high-volume FMPs if it meets the following requirements:

(1) It has been type-tested under § 3175.130;

(2) The documentation required in § 3175.134 has been submitted to the PMT; and

(3) It has been approved by the BLM and placed on the list of type-tested equipment maintained at www/blm.gov.

(b) A transducer of a specific make, model, and URL, in use at an FMP before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], is approved for continued use if:

(1) Data supporting the published performance specification of the transducer are submitted to the PMT in lieu of the documentation required in paragraph (a)(2) of this section; and

(2) It has been approved by the BLM and placed on the list of type-tested equipment maintained at www.blm.gov.

(c) All transducers are approved for use at very-low- and low-volume FMPs.

§ 3175.44 Flow-computer software.

(a) A flow computer of a particular make and model, and equipped with a particular software version, is approved for use at high- and very-high-volume FMPs if the flow computer and software version meet the following requirements:

(1) The documentation required in § 3175.144 has been submitted to the PMT;

(2) The PMT has determined that the flow computer and software version passed the type-testing required in § 3175.140, except as provided in paragraph (b) of this section; and

(3) The BLM has approved the flow computer and software version and has placed them on the list of approved equipment maintained at www.blm.gov.

(b) Software versions (high- and very-high-volume FMPs). (1) Software revisions that affect or have the potential to affect determination of flow rate, determination of volume, determination of heating value, or data or calculations used to verify flow rate, volume, or heating value must be type-tested under § 3175.140.

(2) Software revisions that do not affect or have the potential to affect the determination of flow rate, determination of volume, determination of heating value, or data and calculations used to verify flow rate, volume, or heating value are not required to be type-tested, however, the operator must provide the BLM with a list of these software versions and a brief description of what changes were made from the previous version. (The software manufacturer may provide such information instead of the operator.)

(c) Software versions (low- and very-low-volume FMPs). All software versions are approved for use at low- and very-low-volume FMPs, unless otherwise required by the BLM.

§ 3175.45 Gas chromatographs.

GCs that meet the standards in §§ 3175.117 and 3175.118 for determining heating value and relative density are approved for use.

§ 3175.46 Isolating flow conditioners.

The BLM will list on www.blm.gov the make, model, and size of isolating flow conditioner that is approved for use in conjunction with a flange-tapped orifice plate, so long as the isolating flow conditioner is installed, operated, and maintained in compliance with the requirements of this section. Approval of a particular make and model is obtained as prescribed in this section.

(a) All testing required under this section must be performed at a qualified test facility not affiliated with the flow-conditioner manufacturer.

(b) The operator or manufacturer must test the flow conditioner under API 14.3.2, Annex D (incorporated by reference, see § 3175.30) and submit all test data to the BLM.

(c) The PMT will review the test data to ensure that the device meets the requirements of API 14.3.2, Annex D (incorporated by reference, see § 3175.30) and make a recommendation to the BLM to either approve use of the device, disapprove use of the device, or approve it with conditions for its use.

(d) If approved, the BLM will add the approved make and model, and any applicable conditions of use, to the list maintained at www.blm.gov.

§ 3175.47 Differential primary devices other than flange-tapped orifice plates.

A make, model, and size of differential primary device listed at www.blm.gov is approved for use if it is installed, operated, and maintained in compliance with any applicable conditions of use identified on www.blm.gov for that device. Approval of a particular make and model is obtained as follows:

(a) All testing required under this section must be performed at a qualified test facility not affiliated with the primary device manufacturer.

(b) The primary device must be tested under API 22.2 (incorporated by reference, see § 3175.30).

(c) The operator must submit to the BLM all test data required under API 22.2 (incorporated by reference, see § 3175.30). (The manufacturer of the primary device may submit such information instead of the operator.)

(d) The PMT will review the test data to ensure that the primary device meets the requirements of API 22.2 (incorporated by reference, see § 3175.30) and § 3175.31(c) and (d) and make a recommendation to the BLM to either approve use of the device, disapprove use of the device, or approve its use with conditions.

(e) If the primary device is approved by the BLM, the BLM will add the approved make and model, and any applicable conditions of use, to the list maintained at www.blm.gov.

§ 3175.48 Linear measurement devices.

A make, model, and size of linear measurement device listed at www.blm.gov is approved for use if it is installed, operated, and maintained in compliance with any conditions of use identified on www.blm.gov for that device. Approval of a particular make and model is obtained as follows:

(a) The linear measurement device must be tested at a qualified test facility not affiliated with the linear-measurement-device manufacturer;

(b) The operator or manufacturer must submit to the BLM all test data required by the PMT;

(c) The PMT will review the test data to ensure that the linear measurement device meets the requirements of § 3175.31(c) and (d) and make a recommendation to the BLM to either approve use of the device, disapprove use of the device, or approve its use with conditions; and

(d) If the linear measurement device is approved, the BLM will add the approved make and model, and any applicable conditions of use, to the list maintained at www.blm.gov.

§ 3175.49 Accounting systems.

An accounting system with a name and version listed at www.blm.gov is approved for use in reporting logs and records to the BLM. The approval is specific to those makes and models of flow computers for which testing demonstrates compatibility. Approval for a particular name and version of accounting system used with a particular make and model of flow computer is obtained as follows:

(a) For daily QTRs (see § 3175.104(a)), an operator or vendor must submit daily QTRs to the BLM both from the accounting system and directly from the flow computer for at least 6 consecutive monthly reporting periods;

(b) For hourly QTRs (see § 3175.104(a)), an operator must submit hourly QTRs to the BLM both from the accounting system and directly from the flow computer for at least 15 consecutive daily reporting periods. (A vendor may submit such information on behalf of an operator);

(c) For configuration logs (see § 3175.104(b)), an operator must submit at least 10 configuration logs to the BLM taken at random times covering a span of at least 6 months both from the accounting system and directly from the flow computer. (A vendor may submit such information on behalf of an operator);

(d) For event logs (see § 3175.104(c)), an operator must submit an event log to the BLM containing at least 50 events both from the accounting system and directly from the flow computer. (A vendor may submit such information on behalf of an operator);

(e) For alarm logs (see § 3175.104(d)), an operator must submit an alarm log to the BLM containing at least 50 alarm conditions both from the accounting system and directly from the flow computer (a vendor may submit such information on behalf of an operator);

(f) The BLM may require additional tests and records that may be necessary to determine that the software meets the requirements of § 3175.104(a);

(g) The records retrieved directly from the flow computer in paragraphs (a) through (d) of this section must be unedited;

(h) The records retrieved from the accounting system in paragraphs (a) through (d) must include both edited and unedited versions; and

(i) The BLM will approve the accounting system name and version for use with the make and model of flow computer used for comparison, and add the system name and version to the list of approved systems maintained at www.blm.gov if:

(1) The BLM compares the records retrieved directly from the flow computer with the unedited records from the accounting system and there are no significant discrepancies; and

(2) The BLM compares the records retrieved directly from the flow computer with the edited records from the accounting system and all changes are clearly indicated, the reason for each change is indicated or is available upon request, and the edited version is clearly distinguishable from the unedited version.

§ 3175.60 Timeframes for compliance.

(a) New FMPs. (1) Except as allowed in paragraphs (a)(2) through (4) of this section, the measuring procedures and equipment installed at any FMP on or after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] must comply with all of the requirements of this subpart upon installation.

(2) The gas analysis reporting requirements of § 3175.120(e) and (f) will begin on January 17, 2019.

(3) High- and very-high-volume FMPs must comply with the sampling frequency requirements of § 3175.115(b) starting on January 17, 2019. Between [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] and January 17, 2019, the initial sampling frequencies required at high- and very-high-volume FMPs are those listed in Table 1 to § 3175.110.

(4) Equipment approvals required in §§ 3175.43, 3175.44, and 3175.46 through 3175.49 will be required after January 17, 2019.

(b) Existing FMPs. (1) Except as allowed in § 3175.61, measuring procedures and equipment at any FMP in place before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] must comply with the requirements of this subpart within the timeframes specified in this paragraph (b).

(2) High- and very-high-volume FMPs must comply with:

(i) All of the requirements of this subpart except as specified in paragraphs (b)(2)(ii) and (iii) of this section by January 17, 2018;

(ii) The gas analysis reporting requirements of § 3175.120(e) and (f) starting on January 17, 2019; and

(iii) Equipment approvals required in §§ 3175.43, 3175.44, and 3175.46 through 3175.49 starting on January 17, 2019.

(3) Low-volume FMPs must comply with all of the requirements of this subpart by January 17, 2019.

(4) Very-low-volume FMPs must comply with all of the requirements of this subpart by January 17, 2020.

(c) During the phase-in timeframes in paragraph (b) of this section, measuring procedures and equipment in place before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] must comply with the requirements in place prior to the issuance of this rule, including Onshore Oil and Gas Order No. 5, Measurement of Gas, and applicable NTLs, COAs, and written orders.

(d) Onshore Oil and Gas Order No. 5, Measurement of Gas, statewide NTLs, variance approvals, and written orders that establish requirements or standards related to gas measurement and that are in effect on [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] are rescinded as of:

(1) January 17, 2018 for high-volume and very-high-volume FMPs;

(2) January 17, 2019 for low-volume FMPs; and

(3) January 17, 2020 for very-low-volume FMPs.

§ 3175.61 Grandfathering.

(a) Meter tubes. Meter tubes installed at high- and low-volume FMPs before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] are exempt from the meter tube requirements of API 14.3.2, Subsection 6.2 (incorporated by reference, see § 3175.30), and § 3175.80(f) and (k). For high-volume

FMPs, the BLM will add an uncertainty of ±0.25 percent to the discharge coefficient uncertainty when determining overall meter uncertainty under § 3175.31(a), unless the PMT reviews, and the BLM approves, data showing otherwise. Meter tubes grandfathered under this section must still meet the following requirements:

(1) Orifice plate eccentricity must comply with AGA Report No. 3 (1985), Section 4.2.4 (incorporated by reference, see § 3175.30).

(2) Meter tube construction and condition must comply with AGA Report No. 3 (1985), Section 4.3.4 (incorporated by reference, see § 3175.30).

(3) <u>Meter tube lengths</u>. (i) Meter tube lengths must comply with AGA Report No. 3 (1985), Section 4.4 (dimensions "A" and "A'" from Figures 4-8) (incorporated by reference, see § 3175.30).

(ii) If the upstream meter tube contains a 19-tube bundle flow straightener or isolating flow conditioner, the installation must comply with § 3175.80(g);

(b) <u>EGM software</u>. (1) EGM software installed at very-low-volume FMPs before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] is exempt from the requirements in § 3175.103(a)(1). However, flow-rate calculations must still be calculated in accordance with AGA Report No. 3 (1985), Section 6, or API 14.3.3 (1992), and supercompressibility calculations must still be calculated in accordance with PRCI NX 19 (all incorporated by reference, see § 3175.30).

(2) EGM software installed at low-volume FMPs before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] is exempt from the requirements at § 3175.103(a)(1)(i) if the differential-pressure to static-pressure ratio, based on the monthly average differential pressure and static pressure, is less than the

value of “x_i” shown in API 14.3.3 (1992), Annex G, Table G.1 (incorporated by reference, see § 3175.30). However, flow-rate calculations must still be calculated in accordance with API 14.3.3 (1992) (incorporated by reference, see § 3175.30).

§ 3175.70 Measurement location.

(a) Commingling and allocation. Gas produced from a lease, unit PA, or CA may not be commingled with production from other leases, unit PAs, CAs, or non-Federal properties before the point of royalty measurement, unless prior approval is obtained under 43 CFR subpart 3173.

(b) Off-lease measurement. Gas must be measured on the lease, unit, or CA unless approval for off-lease measurement is obtained under 43 CFR subpart 3173.

§ 3175.80 Flange-tapped orifice plates (primary devices).

Except as stated in this section, as prescribed in Table 1 to this section, or grandfathered under § 3175.61, the standards and requirements in this section apply to all flange-tapped orifice plates (Note: The following table lists the standards in this subpart and the API standards that the operator must follow to install and maintain flange-tapped orifice plates. A requirement applies when a column is marked with an “x” or a number.).

Table 1 to § 3175.80: Standards for Flange-Tapped Orifice Plates

Standards for Flange-Tapped Orifice Plates					
Subject	Reference (API standards incorporated by reference, see § 3175.30)	VL	L	H	VH
Fluid conditions	API 14.3.1, Subsection 4.1	n/a	x	x	x
Orifice plate construction and condition	API 14.3.2, Section 4	x	x	x	x
Orifice plate eccentricity and perpendicularity[2]	API 14.3.2, Subsection 6.2	n/a	x	x	x

Beta ratio range	Paragraph (a) of this section	n/a	x	x	x
Minimum orifice size	§ 3175.80(b)	n/a	n/a	x	x
New FMP orifice plate inspection[1]	§ 3175.80(c)	n/a	x	x	x
Routine orifice plate inspection frequency, in months[1]	§ 3175.80(d)	12	6	3	1
Documentation of orifice plate inspection	§ 3175.80(e)	x	x	x	x
Meter tube construction and condition[2]	§ 3175.80(f)	n/a	x	x	x
Flow conditioners including 19-tube bundles	§ 3175.80(g)	n/a	x	x	x
Basic meter tube inspection frequency, in years[1]	§ 3175.80(h)	n/a	5	2	1
Detailed meter tube inspection[1]	§ 3175.80(i)	n/a	x	x	x
Documentation of detailed meter tube inspection	§ 3175.80(j)	n/a	n/a	x	x
Meter tube length[2]	§ 3175.80(k)	n/a	x	x	x
Thermometer wells	§ 3175.80(l)	n/a	x	x	x
Sample probe location	§ 3175.80(m)	n/a	x	x	x

VL=Very-low-volume FMP; L=Low-volume FMP; H=High-volume FMP; VH=Very-high-volume FMP
[1] = Immediate assessment for non-compliance under § 3175.150
[2] = Applies to all very-high-volume FMPs and meter tubes installed at low- and high-volume FMPs after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. See § 3175.61 for requirements pertaining to meter tubes installed at low- and high-volume FMPs before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

(a) The Beta ratio must be no less than 0.10 and no greater than 0.75.

(b) The orifice bore diameter must be no less than 0.45 inches.

(c) For FMPs measuring production from wells first coming into production, or from existing wells that have been re-fractured (including FMPs already measuring production from one or more other wells), the operator must inspect the orifice plate upon installation and then every 2 weeks thereafter. If the inspection shows that the orifice plate does not comply with API 14.3.2, Section 4 (incorporated by reference, see § 3175.30), the operator must replace the orifice plate. When the inspection shows that the orifice plate complies with API 14.3.2, Section 4 (incorporated by reference, see §

3175.30), the operator thereafter must inspect the orifice plate as prescribed in paragraph (d) of this section.

(d) The operator must pull and inspect the orifice plate at the frequency (in months) identified in Table 1 to this section. The operator must replace orifice plates that do not comply with API 14.3.2, Section 4 (incorporated by reference, see § 3175.30), with an orifice plate that does comply with these standards.

(e) The operator must retain documentation for every plate inspection and must include that documentation as part of the verification report (see § 3175.92(d) for mechanical recorders, or § 3175.102(e) for EGM systems). The operator must provide that documentation to the BLM upon request. The documentation must include:

(1) The information required in § 3170.7(g) of this part;

(2) Plate orientation (bevel upstream or downstream);

(3) Measured orifice bore diameter;

(4) Plate condition (compliance with API 14.3.2, Section 4 (incorporated by reference, see § 3175.30));

(5) The presence of oil, grease, paraffin, scale, or other contaminants on the plate;

(6) Time and date of inspection; and

(7) Whether or not the plate was replaced.

(f) Meter tubes must meet the requirements of API 14.3.2, Subsections 5.1 through 5.4 (incorporated by reference, see § 3175.30).

(g) If flow conditioners are used, they must be either isolating-flow conditioners approved by the BLM and installed under BLM requirements (see § 3175.46) or 19-tube-bundle flow straighteners constructed in compliance with API 14.3.2, Subsections 5.5.2

through 5.5.4, and located in compliance with API 14.3.2, Subsection 6.3 (incorporated by reference, see § 3175.30).

(h) Basic meter tube inspection. The operator must:

(1) Perform a basic inspection of meter tubes within the timeframe (in years) specified in Table 1 to this section;

(2) Conduct a basic inspection that is able to identify obstructions, pitting, and buildup of foreign substances (e.g., grease and scale);

(3) Notify the AO at least 72 hours in advance of performing a basic inspection or submit a monthly or quarterly schedule of basic inspections to the AO in advance;

(4) Conduct additional inspections, as the AO may require, if warranted by conditions, such as corrosive or erosive-flow (e.g., high H_2S or CO_2 content) or signs of physical damage to the meter tube;

(5) Maintain documentation of the findings from the basic meter tube inspection including:

(i) The information required in § 3170.7(g) of this part;

(ii) The time and date of inspection;

(iii) The type of equipment used to make the inspection; and

(iv) A description of findings, including location and severity of pitting, obstructions, and buildup of foreign substances; and

(6) Complete the first inspection after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER] within the timeframes (in years) given in Table 1 to this section.

(i) Detailed meter tube inspection. (1) Within 30 days of a basic inspection that indicates the presence of pitting, obstructions, or a buildup of foreign substances, the operator must:

(i) For low-volume FMPs, clean the meter tube of obstructions and foreign substances;

(ii) For high- and very-high-volume FMPs, physically measure and inspect the meter tube to determine if the meter tube complies with API 14.3.2, Subsections 5.1 through 5.4 and API 14.3.2, Subsection 6.2 (incorporated by reference, see § 3175.30), or the requirements under § 3175.61(a), if the meter tube is grandfathered under § 3175.61(a). If the meter tube does not comply with the applicable standards, the operator must repair the meter tube to bring the meter tube into compliance with these standards or replace the meter tube with one that meets these standards; or

(iii) Submit a request to the AO for an extension of the 30-day timeframe, justifying the need for the extension.

(2) For all high- and very-high volume FMPs installed after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER], the operator must perform a detailed inspection under paragraph (i)(1)(ii) of this section before operation of the meter. The operator may submit documentation showing that the meter tube complies with API 14.3.2, Subsections 5.1 through 5.4 (incorporated by reference, see § 3175.30) in lieu of performing a detailed inspection.

(3) The operator must notify the AO at least 24 hours before performing a detailed inspection.

(j) The operator must retain documentation of all detailed meter tube inspections, demonstrating that the meter tube complies with API 14.3.2, Subsections 5.1 through 5.4

(incorporated by reference, see § 3175.30), and showing all required measurements. The operator must provide such documentation to the BLM upon request for every meter-tube inspection. Documentation must also include the information required in § 3170.7(g) of this part.

(k) Meter tube lengths. (1) Meter-tube lengths and the location of 19-tube-bundle flow straighteners, if applicable, must comply with API 14.3.2, Subsection 6.3 (incorporated by reference, see § 3175.30).

(2) For Beta ratios of less than 0.5, the location of 19-tube bundle flow straighteners installed in compliance with AGA Report No. 3 (1985), Section 4.4 (incorporated by reference, see § 3175.30), also complies with the location of 19-tube bundle flow straighteners as required in paragraph (k)(1) of this section.

(3) If the diameter ratio (β) falls between the values in Tables 7, 8a, or 8b of API 14.3.2, Subsection 6.3 (incorporated by reference, see § 3175.30), the length identified for the larger diameter ratio in the appropriate Table is the minimum requirement for meter-tube length and determines the location of the end of the 19-tube-bundle flow straightener closest to the orifice plate. For example, if the calculated diameter ratio is 0.41, use the table entry for a 0.50 diameter ratio.

(l) Thermometer wells. (1) Thermometer wells used for determining the flowing temperature of the gas as well as thermometer wells used for verification (test well) must be located in compliance with API 14.3.2, Subsection 6.5 (incorporated by reference, see § 3175.30).

(2) Thermometer wells must be located in such a way that they can sense the same flowing gas temperature that exists at the orifice plate. The operator may accomplish

this by physically locating the thermometer well(s) in the same ambient temperature conditions as the primary device (such as in a heated meter house) or by installing insulation and/or heat tracing along the entire meter run. If the operator chooses to use insulation to comply with this requirement, the AO may prescribe the quality of the insulation based on site specific factors such as ambient temperature, flowing temperature of the gas, composition of the gas, and location of the thermometer well in relation to the orifice plate (i.e., inside or outside of a meter house).

(3) Where multiple thermometer wells have been installed in a meter tube, the flowing temperature must be measured from the thermometer well closest to the primary device.

(4) Thermometer wells used to measure or verify flowing temperature must contain a thermally conductive liquid.

(m) The sampling probe must be located as specified in § 3175.112(b).

§ 3175.90 Mechanical recorder (secondary device).

(a) The operator may use a mechanical recorder as a secondary device only on very-low-volume and low-volume FMPs.

(b) Table 1 to this section lists the standards that the operator must follow to install, operate, and maintain mechanical recorders. A requirement applies when a column is marked with an “x” or a number.

Table 1 to § 3175.90: Standards for Mechanical Recorders

Standards for Mechanical Recorders			
Subject	Reference	VL	L
Applications for use	Paragraph (a) of this section	x	x
Manifolds and gauge/impulse lines	§ 3175.91(a)	n/a	x
Differential-pressure pen position	§ 3175.91(b)	n/a	x

Flowing temperature recording	§ 3175.91(c)	n/a	x
On-site data requirements	§ 3175.91(d)	x	x
Operating within the element ranges	§ 3175.91(e)	x	x
Verification after installation or following repair[1]	§ 3175.92(a)	x	x
Routine verification and verification frequency, in months[1]	§ 3175.92(b)	6	3
Routine verification procedures	§ 3175.92(c)	x	x
Documentation of verification	§ 3175.92(d)	x	x
Notification of verification	§ 3175.92(e)	x	x
Volume correction	§ 3175.92(f)	n/a	x
Test equipment recertification	§ 3175.92(g)	x	x
Integration statement requirements	§ 3175.93	x	x
Volume determination	§ 3175.94(a)	x	x
Atmospheric pressure	§ 3175.94(b)	x	x
VL=Very-low-volume FMP; L=Low-volume FMP [1] = Immediate assessment for non-compliance under § 3175.150			

§ 3175.91 Installation and operation of mechanical recorders.

(a) Gauge lines connecting the pressure taps to the mechanical recorder must:

(1) Have a nominal diameter of not less than 3/8 inch, including ports and valves;

(2) Be sloped upwards from the pressure taps at a minimum pitch of 1 inch per foot of length with no visible sag;

(3) Be the same internal diameter along their entire length;

(4) Not include tees, except for the static-pressure line;

(5) Not be connected to more than one differential-pressure bellows and static-pressure element, or to any other device; and

(6) Be no longer than 6 feet.

(b) The differential-pressure pen must record at a minimum reading of 10 percent of the differential-pressure-bellows range for the majority of the flowing period. This requirement does not apply to inverted charts.

(c) The flowing temperature of the gas must be continuously recorded and used in the volume calculations under § 3175.94(a)(1).

(d) The following information must be maintained at the FMP in a legible condition, in compliance with § 3170.7(g) of this part, and accessible to the AO at all times:

(1) Differential-pressure-bellows range;

(2) Static-pressure-element range;

(3) Temperature-element range;

(4) Relative density (specific gravity) of the gas;

(5) Static-pressure units of measure (psia or psig);

(6) Meter elevation;

(7) Meter-tube inside diameter;

(8) Primary device type;

(9) Orifice-bore or other primary-device dimensions necessary for device verification, Beta- or area-ratio determination, and gas-volume calculation;

(10) Make, model, and location of approved isolating flow conditioners, if used;

(11) Location of the downstream end of 19-tube-bundle flow straighteners, if used;

(12) Date of last primary-device inspection; and

(13) Date of last meter verification.

(e) The differential pressure, static pressure, and flowing temperature elements must be operated between the lower- and upper-calibrated limits of the respective elements.

§ 3175.92 Verification and calibration of mechanical recorders.

(a) Verification after installation or following repair. (1) Before performing any verification of a mechanical recorder required in this part, the operator must perform a leak test. The verification must not proceed if leaks are present. The leak test must be conducted in a manner that will detect leaks in the following:

(i) All connections and fittings of the secondary device, including meter manifolds and verification equipment;

(ii) The isolation valves; and

(iii) The equalizer valves.

(2) The operator must adjust the time lag between the differential- and static-pressure pens, if necessary, to be 1/96 of the chart rotation period, measured at the chart hub. For example, the time lag is 15 minutes on a 24-hour test chart and 2 hours on an 8-day test chart.

(3) The meter's differential pen arc must be able to duplicate the test chart's time arc over the full range of the test chart, and must be adjusted, if necessary.

(4) The as-left values must be verified in the following sequence against a certified pressure device for the differential-pressure and static-pressure elements (if the static-pressure pen has been offset for atmospheric pressure, the static-pressure element range is in psia):

(i) Zero (vented to atmosphere);

(ii) 50 percent of element range;

(iii) 100 percent of element range;

(iv) 80 percent of element range;

(v) 20 percent of element range; and

(vi) Zero (vented to atmosphere).

(5) The following as-left temperatures must be verified by placing the temperature probe in a water bath with a certified test thermometer:

(i) Approximately 10° F below the lowest expected flowing temperature;

(ii) Approximately 10° F above the highest expected flowing temperature; and

(iii) At the expected average flowing temperature.

(6) If any of the readings required in paragraph (a)(4) or (5) of this section vary from the test device reading by more than the tolerances shown in Table 1 to this section, the operator must replace and verify the element for which readings were outside the applicable tolerances before returning the meter to service.

Table 1 to § 3175.92: Mechanical Recorder Tolerances

Mechanical Recorder Tolerances	
Element	Allowable Error
Differential Pressure	±0.5%
Static Pressure	±1.0%
Temperature	±2° F

(7) If the static-pressure pen is offset for atmospheric pressure:

(i) The atmospheric pressure must be calculated under appendix A to this subpart; and

(ii) The pen must be offset prior to obtaining the as-left verification values required in paragraph (a)(4) of this section.

(b) Routine verification frequency. The differential pressure, static pressure, and temperature elements must be verified under the requirements of this section at the frequency specified in Table 1 to § 3175.90, in months.

(c) Routine verification procedures. (1) Before performing any verification required in this part, the operator must perform a leak test in the manner required under paragraph (a)(1) of this section.

(2) No adjustments to the pens or linkages may be made until an as-found verification is obtained. If the static pen has been offset for atmospheric pressure, the static pen must not be reset to zero until the as-found verification is obtained.

(3) The operator must obtain the as-found values of differential and static pressure against a certified pressure device at the readings listed in paragraph (a)(4) of this section, with the following additional requirements:

(i) If there is sufficient data on site to determine the point at which the differential and static pens normally operate, the operator must also obtain an as-found value at those points;

(ii) If there is not sufficient data on site to determine the points at which the differential and static pens normally operate, the operator must also obtain as-found values at 5 percent of the element range and 10 percent of the element range; and

(iii) If the static-pressure pen has been offset for atmospheric pressure, the static-pressure element range is in units of psia.

(4) The as-found value for temperature must be taken using a certified test thermometer placed in a test thermometer well if there is flow through the meter and the meter tube is equipped with a test thermometer well. If there is no flow through the

meter or if the meter is not equipped with a test thermometer well, the temperature probe must be verified by placing it along with a test thermometer in an insulated water bath.

(5) The element undergoing verification must be calibrated according to manufacturer specifications if any of the as-found values determined under paragraph (c)(3) or (4) of this section are not within the tolerances shown in Table 1 to this section, when compared to the values applied by the test equipment.

(6) The operator must adjust the time lag between the differential- and static-pressure pens, if necessary, to be 1/96 of the chart rotation period, measured at the chart hub. For example, the time lag is 15 minutes on a 24-hour test chart and 2 hours on an 8-day test chart.

(7) The meter's differential pen arc must be able to duplicate the test chart's time arc over the full range of the test chart, and must be adjusted, if necessary.

(8) If any adjustment to the meter was made, the operator must perform an as-left verification on each element adjusted using the procedures in paragraphs (c)(3) and (4) of this section.

(9) If, after an as-left verification, any of the readings required in paragraph (c)(3) or (4) of this section vary by more than the tolerances shown in Table 1 to this section when compared with the test-device reading, any element which has readings that are outside of the applicable tolerances must be replaced and verified under this section before the operator returns the meter to service.

(10) If the static-pressure pen is offset for atmospheric pressure:

(i) The atmospheric pressure must be calculated under appendix A to this subpart; and

(ii) The pen must be offset prior to obtaining the as-left verification values required in paragraph (c)(3) of this section.

(d) The operator must retain documentation of each verification, as required under § 3170.7(g) of this part, and submit it to the BLM upon request. This documentation must include:

(1) The time and date of the verification and the prior verification date;

(2) Primary-device data (meter-tube inside diameter and differential-device size and Beta or area ratio) if the orifice plate is pulled and inspected;

(3) The type and location of taps (flange or pipe, upstream or downstream static tap);

(4) Atmospheric pressure used to offset the static-pressure pen, if applicable;

(5) Mechanical recorder data (make, model, and differential pressure, static pressure, and temperature element ranges);

(6) The normal operating points for differential pressure, static pressure, and flowing temperature;

(7) Verification points (as-found and applied) for each element;

(8) Verification points (as-left and applied) for each element, if a calibration was performed;

(9) Names, contact information, and affiliations of the person performing the verification and any witness, if applicable; and

(10) Remarks, if any.

(e) Notification of verification. (1) For verifications performed after installation or following repair, the operator must notify the AO at least 72 hours before conducting the verifications.

(2) For routine verifications, the operator must notify the AO at least 72 hours before conducting the verification or submit a monthly or quarterly verification schedule to the AO in advance.

(f) If, during the verification, the combined errors in as-found differential pressure, static pressure, and flowing temperature taken at the normal operating points tested result in a flow-rate error greater than 2 percent or 2 Mcf/day, whichever is greater, the volumes reported on the OGOR and on royalty reports submitted to ONRR must be corrected beginning with the date that the inaccuracy occurred. If that date is unknown, the volumes must be corrected beginning with the production month that includes the date that is half way between the date of the last verification and the date of the current verification. For example: Meter verification determined that the meter was reading 4 Mcf/day high at the normal operating points. The average flow rate measured by the meter is 90 Mcf/day. There is no indication of when the inaccuracy occurred. The date of the current verification was December 15, 2015. The previous verification was conducted on June 15, 2015. The royalty volumes reported on OGOR B that were based on this meter must be corrected for the 4 Mcf/day error back to September 15, 2015.

(g) Test equipment used to verify or calibrate elements at an FMP must be certified at least every 2 years. Documentation of the recertification must be on-site during all verifications and must show:

(1) Test equipment serial number, make, and model;

(2) The date on which the recertification took place;

(3) The test equipment measurement range; and

(4) The uncertainty determined or verified as part of the recertification.

§ 3175.93 Integration statements.

An unedited integration statement must be retained and made available to the BLM upon request. The integration statement must contain the following information:

(a) The information required in § 3170.7(g) of this part;

(b) The name of the company performing the integration;

(c) The month and year for which the integration statement applies;

(d) Meter-tube inside diameter (inches);

(e) The following primary device information, as applicable:

(i) Orifice bore diameter (inches); or

(ii) Beta or area ratio, discharge coefficient, and other information necessary to calculate the flow rate;

(f) Relative density (specific gravity);

(g) CO_2 content (mole percent);

(h) N_2 content (mole percent);

(i) Heating value calculated under § 3175.125 (Btu/standard cubic feet);

(j) Atmospheric pressure or elevation at the FMP;

(k) Pressure base;

(l) Temperature base;

(m) Static-pressure tap location (upstream or downstream);

(n) Chart rotation (hours or days);

(o) Differential-pressure bellows range (inches of water);

(p) Static-pressure element range (psi); and

(q) For each chart or day integrated:

(i) The time and date on and time and date off;

(ii) Average differential pressure (inches of water);

(iii) Average static pressure;

(iv) Static-pressure units of measure (psia or psig);

(v) Average temperature (° F);

(vi) Integrator counts or extension;

(vii) Hours of flow; and

(viii) Volume (Mcf).

§ 3175.94 Volume determination.

(a) The volume for each chart integrated must be determined as follows:

$$V = IMV \times IV$$

Where:

V = reported volume, Mcf
IMV = integral multiplier value, as calculated under this section
IV = the integral value determined by the integration process (also known as the "extension," "integrated extension," and "integrator count")

(1) If the primary device is a flange-tapped orifice plate, a single IMV must be calculated for each chart or chart interval using the following equation:

$$IMV = 7709.61 \frac{C_d Y d^2}{\sqrt{1-\beta^4}} \sqrt{\frac{Z_b}{G_r Z_f T_f}}$$

Where:

C_d = discharge coefficient or flow coefficient, calculated under API 14.3.3 or AGA Report No. 3 (1985), Section 5 (incorporated by reference, see § 3175.30)

β = Beta ratio.
Y = gas expansion factor, calculated under API 14.3.3, Subsection 5.6 or AGA Report No. 3 (1985), Section 5 (incorporated by reference, see § 3175.30)
d = orifice diameter, in inches
Z_b = supercompressibility at base pressure and temperature
G_r = relative density (specific gravity)
Z_f = supercompressibility at flowing pressure and temperature
T_f = average flowing temperature, in degrees Rankine

(2) For other types of primary devices, the IMV must be calculated using the equations and procedures recommended by the PMT and approved by the BLM, specific to the make, model, size, and area ratio of the primary device being used.

(3) Variables that are functions of differential pressure, static pressure, or flowing temperature (e.g., C_d, Y, Z_f) must use the average values of differential pressure, static pressure, and flowing temperature as determined from the integration statement and reported on the integration statement for the chart or chart interval integrated. The flowing temperature must be the average flowing temperature reported on the integration statement for the chart or chart interval being integrated.

(b) Atmospheric pressure used to convert static pressure in psig to static pressure in psia must be determined under appendix A to this subpart.

§ 3175.100 Electronic gas measurement (secondary and tertiary device).

Except as stated in this section, as prescribed in Table 1 to this section, or grandfathered under § 3175.61, the standards and requirements in this section apply to all EGM systems used at FMPs (Note: The following table lists the standards in this subpart and the API standards that the operator must follow to install and maintain EGM systems. A requirement applies when a column is marked with an “x” or a number.).

Table 1 to § 3175.100: Standards for Electronic Gas Measurement Systems

Standards for Electronic Gas Measurement Systems					
Subject	Reference (API standards incorporated by reference, see § 3175.30)	VL	L	H	VH
EGM system commissioning	API 21.1, Subsection 7.3	n/a	x	x	x
Access and data security	API 21.1, Section 9	x	x	x	x
No-flow cutoff	API 21.1, Subsection 4.4.5	x	x	x	x
Manifolds and gauge lines	§ 3175.101(a)	n/a	x	x	x
Display requirements	§ 3175.101(b)	x	x	x	x
On-site information	§ 3175.101(c)	x	x	x	x
Operating within the calibrated limits	§ 3175.101(d)	n/a	x	x	x
Flowing-temperature measurement	§ 3175.101(e)	n/a	x	x	x
Verification after installation or following repair[1]	§ 3175.102(a)	x	x	x	x
Routine verification frequency, in months[1]	§ 3175.102(b)	12	6	3	3
Routine verification procedures	§ 3175.102(c)	x	x	x	x
Redundancy verification	§ 3175.102(d)	x	x	x	x
Documentation of verification	§ 3175.102(e)	x	x	x	x
Notification of verification	§ 3175.102(f)	x	x	x	x
Volume correction	§ 3175.102(g)	n/a	x	x	x
Test-equipment requirements	§ 3175.102(h)	x	x	x	x
Flow-rate calculation[2]	§ 3175.103(a)	x	x	x	x
Atmospheric pressure	§ 3175.103(b)	x	x	x	x
Volume calculation	§ 3175.103(c)	x	x	x	x
QTR requirements	§ 3175.104(a)	x	x	x	x
Configuration log requirements	§ 3175.104(b)	x	x	x	x
Event log	§ 3175.104(c)	x	x	x	x
Alarm log	§ 3175.104(d)	x	x	x	x
Accounting systems	§ 3175.104(e)	x	x	x	x

VL=Very-low-volume FMP; L=Low-volume FMP; H=High-volume FMP; VH=Very-high-volume FMP,
[1] = Immediate assessment for non-compliance under § 3175.150
[2] = Applies to all high- and very-high-volume FMPs and FMPs installed at low- and very-low-volume FMPs after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]. See § 3175.61 for requirements pertaining to FMPs installed at low- and very-low-volume FMPs before [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

§ 3175.101 Installation and operation of electronic gas measurement systems.

(a) Manifolds and gauge lines connecting the pressure taps to the secondary device must:

(1) Have a nominal diameter of not less than 3/8-inch, including ports and valves;

(2) Be sloped upwards from the pressure taps at a minimum pitch of 1 inch per foot of length with no visible sag;

(3) Have the same internal diameter along their entire length;

(4) Not include tees except for the static-pressure line;

(5) Not be connected to any other devices or more than one differential pressure and static-pressure transducer. If the operator is employing redundancy verification, two differential pressure and two static-pressure transducers may be connected; and

(6) Be no longer than 6 feet.

(b) Each FMP must include a display, which must:

(1) Be readable without the need for data-collection units, laptop computers, a password, or any special equipment;

(2) Be on site and in a location that is accessible to the AO;

(3) Include the units of measure for each required variable;

(4) Display the software version and previous-day's volume, as well as the following variables consecutively:

(i) Current flowing static pressure with units (psia or psig);

(ii) Current differential pressure (inches of water);

(iii) Current flowing temperature (° F); and

(iv) Current flow rate (Mcf/day or scf/day); and

(5) Either display or post on site and accessible to the AO an hourly or daily QTR (see § 3175.104(a)) no more than 31 days old showing the following information:

(i) Previous-period (for this section, previous period means at least 1 day prior, but no longer than 1 month prior) average differential pressure (inches of water);

(ii) Previous-period average static pressure with units (psia or psig); and

(iii) Previous-period average flowing temperature (° F).

(c) The following information must be maintained at the FMP in a legible condition, in compliance with § 3170.7(g) of this part, and accessible to the AO at all times:

(1) The unique meter ID number;

(2) Relative density (specific gravity);

(3) Elevation of the FMP;

(4) Primary device information, such as orifice bore diameter (inches) or Beta or area ratio and discharge coefficient, as applicable;

(5) Meter-tube mean inside diameter;

(6) Make, model, and location of approved isolating flow conditioners, if used;

(7) Location of the downstream end of 19-tube-bundle flow straighteners, if used;

(8) For self-contained EGM systems, make and model number of the system;

(9) For component-type EGM systems, make and model number of each transducer and the flow computer;

(10) URL and upper calibrated limit for each transducer;

(11) Location of the static-pressure tap (upstream or downstream);

(12) Last primary-device inspection date; and

(13) Last secondary device verification date.

(d) The differential pressure, static pressure, and flowing temperature transducers must be operated between the lower and upper calibrated limits of the transducer. The BLM may approve the differential pressure to exceed the upper calibrated limit of the differential-pressure transducer for brief periods in plunger lift operations; however, the differential pressure may not exceed the URL.

(e) The flowing temperature of the gas must be continuously measured and used in the flow-rate calculations under API 21.1, Section 4 (incorporated by reference, see § 3175.30).

§ 3175.102 Verification and calibration of electronic gas measurement systems.

(a) Transducer verification and calibration after installation or repair. (1) Before performing any verification required in this section, the operator must perform a leak test in the manner prescribed in § 3175.92(a)(1).

(2) The operator must verify the points listed in API 21.1, Subsection 7.3.3 (incorporated by reference, see § 3175.30), by comparing the values from the certified test device with the values used by the flow computer to calculate flow rate. If any of these as-left readings vary from the test equipment reading by more than the tolerance determined by API 21.1, Subsection 8.2.2.2, Equation 24 (incorporated by reference, see § 3175.30), then that transducer must be replaced and the new transducer must be tested under this paragraph.

(3) For absolute static-pressure transducers, the value of atmospheric pressure used when the transducer is vented to atmosphere must be calculated under appendix A to this subpart, measured by a NIST-certified barometer with a stated accuracy of ±0.05 psi or better, or obtained from an absolute-pressure calibration device.

(4) Before putting a meter into service, the differential-pressure transducer must be tested at zero with full working pressure applied to both sides of the transducer. If the absolute value of the transducer reading is greater than the reference accuracy of the transducer, expressed in inches of water column, the transducer must be re-zeroed.

(b) Routine verification frequency. (1) If redundancy verification under paragraph (d) of this section is not used, the differential pressure, static pressure, and temperature transducers must be verified under the requirements of paragraph (c) of this section at the frequency specified in Table 1 to § 3175.100, in months; or

(2) If redundancy verification under paragraph (d) of this section is used, the differential pressure, static pressure, and temperature transducers must be verified under the requirements of paragraph (d) of this section. In addition, the transducers must be verified under the requirements of paragraph (c) of this section at least annually.

(c) Routine verification procedures. Verifications must be performed according to API 21.1, Subsection 8.2 (incorporated by reference, see § 3175.30), with the following exceptions, additions, and clarifications:

(1) Before performing any verification required under this section, the operator must perform a leak test consistent with § 3175.92(a)(1).

(2) An as-found verification for differential pressure, static pressure and temperature must be conducted at the normal operating point of each transducer.

(i) The normal operating point is the mean value taken over a previous time period not less than 1 day or greater than 1 month. Acceptable mean values include means weighted based on flow time and flow rate.

(ii) For differential and static-pressure transducers, the pressure applied to the transducer for this verification must be within five percentage points of the normal operating point. For example, if the normal operating point for differential pressure is 17 percent of the upper calibrated limit, the normal point verification pressure must be between 12 percent and 22 percent of the upper calibrated limit.

(iii) For the temperature transducer, the water bath or test thermometer well must be within 20° F of the normal operating point for temperature.

(3) If any of the as-found values are in error by more than the manufacturer's specification for stability or drift -- as adjusted for static pressure and ambient temperature -- on two consecutive verifications, that transducer must be replaced prior to returning the meter to service.

(4) If a transducer is calibrated, the as-left verification must include the normal operating point of that transducer, as defined in paragraph (c)(2) of this section.

(5) The as-found values for differential pressure obtained with the low side vented to atmospheric pressure must be corrected to working-pressure values using API 21.1, Annex H, Equation H.1 (incorporated by reference, see § 3175.30).

(6) The verification tolerance for differential and static pressure is defined by API 21.1, Subsection 8.2.2.2, Equation 24 (incorporated by reference, see § 3175.30). The verification tolerance for temperature is equivalent to the uncertainty of the temperature transmitter or 0.5 °F, whichever is greater.

(7) All required verification points must be within the verification tolerance before returning the meter to service.

(8) Before putting a meter into service, the differential-pressure transducer must be tested at zero with full working pressure applied to both sides of the transducer. If the absolute value of the transducer reading is greater than the reference accuracy of the transducer, expressed in inches of water column, the transducer must be re-zeroed.

(d) Redundancy verification procedures. Redundancy verifications must be performed as required under API 21.1, Subsection 8.2 (incorporated by reference, see § 3175.30), with the following exceptions, additions, and clarifications:

(1) The operator must identify which set of transducers is used for reporting on the OGOR (the primary transducers) and which set of transducers is used as a check (the check set of transducers);

(2) For every calendar month, the operator must compare the flow-time linear averages of differential pressure, static pressure, and temperature readings from the primary transducers with those from the check transducers;

(3)(i) If for any transducer the difference between the averages exceeds the tolerance defined by the following equation:

$$Tolerance = \sqrt{A_p^2 + A_c^2}$$

Where:

A_p is the reference accuracy of the primary transducer and

A_c is the reference accuracy of the check transducer.

(ii) The operator must verify both the primary and check transducer under paragraph (c) of this section within the first 5 days of the month following the month in which the redundancy verification was performed. For example, if the redundancy verification for

March reveals that the difference in the flow-time linear averages of differential pressure exceeded the verification tolerance, both the primary and check differential-pressure transducers must be verified under paragraph (c) of this section by April 5th.

(e) The operator must retain documentation of each verification for the period required under § 3170.7 of this part, including calibration data for transducers that were replaced, and submit it to the BLM upon request.

(1) For routine verifications, this documentation must include:

(i) The information required in § 3170.7(g) of this part;

(ii) The time and date of the verification and the last verification date;

(iii) Primary device data (meter-tube inside diameter and differential-device size, Beta or area ratio);

(iv) The type and location of taps (flange or pipe, upstream or downstream static tap);

(v) The flow computer make and model;

(vi) The make and model number for each transducer, for component-type EGM systems;

(vii) Transducer data (make, model, differential, static, temperature URL, and upper calibrated limit);

(viii) The normal operating points for differential pressure, static pressure, and flowing temperature;

(ix) Atmospheric pressure;

(x) Verification points (as-found and applied) for each transducer;

(xi) Verification points (as-left and applied) for each transducer, if calibration was performed;

(xii) The differential device inspection date and condition (e.g., clean, sharp edge, or surface condition);

(xiii) Verification equipment make, model, range, accuracy, and last certification date;

(xiv) The name, contact information, and affiliation of the person performing the verification and any witness, if applicable; and

(xv) Remarks, if any.

(2) For redundancy verification checks, this documentation must include;

(i) The information required in § 3170.7(g) of this part;

(ii) The month and year for which the redundancy check applies;

(iii) The makes, models, upper range limits, and upper calibrated limits of the primary set of transducers;

(iv) The makes, models, upper range limits, and upper calibrated limits of the check set of transducers;

(v) The information required in API 21.1, Annex I (incorporated by reference, see § 3175.30);

(vii) The tolerance for differential pressure, static pressure, and temperature as calculated under paragraph (d)(2) of this section; and

(viii) Whether or not each transducer required verification under paragraph (c) of this section.

(f) Notification of verification. (1) For verifications performed after installation or following repair, the operator must notify the AO at least 72 hours before conducting the verifications.

(2) For routine verifications, the operator must notify the AO at least 72 hours before conducting the verification or submit a monthly or quarterly verification schedule to the AO in advance.

(g) If, during the verification, the combined errors in as-found differential pressure, static pressure, and flowing temperature taken at the normal operating points tested result in a flow-rate error greater than 2 percent or 2 Mcf/day, whichever is greater, the volumes reported on the OGOR and on royalty reports submitted to ONRR must be corrected beginning with the date that the inaccuracy occurred. If that date is unknown, the volumes must be corrected beginning with the production month that includes the date that is half way between the date of the last verification and the date of the present verification. See the example in § 3175.92(f).

(h) Test equipment requirements. (1) Test equipment used to verify or calibrate transducers at an FMP must be certified at least every 2 years. Documentation of the certification must be on site and made available to the AO during all verifications and must show:

(i) The test equipment serial number, make, and model;

(ii) The date on which the recertification took place;

(iii) The range of the test equipment; and

(iv) The uncertainty determined or verified as part of the recertification.

(2) Test equipment used to verify or calibrate transducers at an FMP must meet the following accuracy standards:

(i) The accuracy of the test equipment, stated in actual units of measure, must be no greater than 0.5 times the reference accuracy of the transducer being verified, also stated in actual units of measure; or

(ii) The equipment must have a stated accuracy of at least 0.10 percent of the upper calibrated limit of the transducer being verified.

§ 3175.103 Flow rate, volume, and average value calculation.

(a) The flow rate must be calculated as follows:

(1) For flange-tapped orifice plates, the flow rate must be calculated under:

(i) API 14.3.3, Section 4 and API 14.3.3, Section 5 (incorporated by reference, see § 3175.30); and

(ii) AGA Report No. 8 (incorporated by reference, see § 3175.30), for supercompressibility.

(2) For primary devices other than flange-tapped orifice plates, for which there are no industry standards, the flow rate must be calculated under the equations and procedures recommended by the PMT and approved by the BLM, specific to the make, model, size, and area ratio of the primary device used.

(b) Atmospheric pressure used to convert static pressure in psig to static pressure in psia must be determined under API 21.1, Subsection 8.3.3 (incorporated by reference, see § 3175.30).

(c) Hourly and daily gas volumes, average values of the live input variables, flow time, and integral value or average extension as required under § 3175.104 must be determined under API 21.1, Section 4 and API 21.1, Annex B (incorporated by reference, see § 3175.30).

§ 3175.104 Logs and records.

(a) The operator must retain, and submit to the BLM upon request, the original, unaltered, unprocessed, and unedited daily and hourly QTRs, which must contain the information identified in API 21.1, Subsection 5.2 (incorporated by reference, see § 3175.30), with the following additions and clarifications:

(1) The information required in § 3170.7(g) of this part;

(2) The volume, flow time, and integral value or average extension must be reported to at least 5 decimal places. The average differential pressure, static pressure, and temperature as calculated in § 3175.103(c), must be reported to at least three decimal places; and

(3) A statement of whether the operator has submitted the integral value or average extension.

(b) The operator must retain, and submit to the BLM upon request, the original, unaltered, unprocessed, and unedited configuration log, which must contain the information specified in API 21.1, Subsection 5.4 (including the flow-computer snapshot report in API 21.1, Subsection 5.4.2), and API 21.1, Annex G (incorporated by reference, see § 3175.30), with the following additions and clarifications:

(1) The information required in § 3170.7(g) of this part;

(2) Software/firmware identifiers under API 21.1, Subsection 5.3 (incorporated by reference, see § 3175.30);

(3) For very-low-volume FMPs only, the fixed temperature, if not continuously measured (˚F); and

(4) The static-pressure tap location (upstream or downstream).

(c) The operator must retain, and submit to the BLM upon request, the original, unaltered, unprocessed, and unedited event log. The event log must comply with API 21.1, Subsection 5.5 (incorporated by reference, see § 3175.30), with the following additions and clarifications: The event log must have sufficient capacity and must be retrieved and stored at intervals frequent enough to maintain a continuous record of events as required under § 3170.7 of this part, or the life of the FMP, whichever is shorter.

(d) The operator must retain an alarm log and provide it to the BLM upon request. The alarm log must comply with API 21.1, Subsection 5.6 (incorporated by reference, see § 3175.30).

(e) Records may only be submitted from accounting system names and versions and flow computer makes and models that have been approved by the BLM (see § 3175.49).

§ 3175.110 Gas sampling and analysis.

Except as stated in this section or as prescribed in Table 1 to this section, the standards and requirements in this section apply to all gas sampling and analyses. (Note: The following table lists the standards in this subpart and the API standards that the operator must follow to take a gas sample, analyze the gas sample, and report the findings of the gas analysis. A requirement applies when a column is marked with an "x" or a number.)

Table 1 to § 3175.110: Gas Sampling and Analysis

Gas Sampling and Analysis					
Subject	Reference	VL	L	H	VH
Methods of sampling	§ 3175.111(a)	x	x	x	x
Heating requirements	§ 3175.111(b)	x	x	x	x
Samples taken from probes	§ 3175.112(a)	n/a	x	x	x
Location of sample probe	§ 3175.112(b)	n/a	x	x	x
Sample probe design and type	§ 3175.112(c)	n/a	x	x	x

Sample tubing	§ 3175.112(d)	n/a	x	x	x
Spot sample while flowing	§ 3175.113(a)	x	x	x	x
Notification of spot samples	§ 3175.113(b)	x	x	x	x
Sample cylinder requirements	§ 3175.113(c)	x	x	x	x
Spot sampling using portable GCs	§ 3175.113(d)	x	x	x	x
Allowable methods of spot sampling	§ 3175.114(a)	x	x	x	x
Low pressure sampling	§ 3175.114(b)	x	x	x	x
Spot sampling frequency, low- and very-low-volume FMPs (in months)[1]	§ 3175.115(a)	12	6	n/a	n/a
Initial spot sampling frequency, high- and very-high-volume FMPs (in months)[1]	§ 3175.115(a)	n/a	n/a	3	1
Adjustment of spot sampling frequencies, high- and very-high-volume FMPs	§ 3175.115(b)	n/a	n/a	x	x
Maximum time between samples	§ 3175.115(c)	x	x	x	x
Installation of composite sampler or on-line GC	§ 3175.115(d)	x	x	x	x
Removal of composite sampler or on-line GC	§ 3175.115(e)	x	x	x	x
Composite sampling methods	§ 3175.116	x	x	x	x
On-line gas chromatographs	§ 3175.117	x	x	x	x
Gas chromatograph requirements	§ 3175.118	x	x	x	x
Minimum components to analyze	§ 3175.119(a)	x	x	x	x
Extended analysis	§ 3175.119(b) and (c)	n/a	n/a	x	x
Gas analysis report requirements	§ 3175.120	x	x	x	x
Effective date of spot and composite samples	§ 3175.121	x	x	x	x
VL=Very-low-volume FMP; L=Low-volume FMP; H=High-volume FMP; VH=Very-high-volume FMP, [1] = Immediate assessment for non-compliance under § 3175.150					

§ 3175.111 General sampling requirements.

(a) Samples must be taken by one of the following methods:

(1) Spot sampling under §§ 3175.113 through 3175.115;

(2) Flow-proportional composite sampling under § 3175.116; or

(3) On-line gas chromatograph under § 3175.117.

(b) At all times during the sampling process, the minimum temperature of all gas sampling components must be the lesser of:

(1) The flowing temperature of the gas measured at the time of sampling; or

(2) 30° F above the calculated hydrocarbon dew point of the gas.

§ 3175.112 Sampling probe and tubing.

(a) All gas samples must be taken from a sample probe that complies with the requirements of paragraphs (b) and (c) of this section.

(b) Location of sample probe. (1) The sample probe must be located in the meter tube in accordance with API 14.1, Subsection 6.4.2 (incorporated by reference, see § 3175.30), and must be the first obstruction downstream of the primary device.

(2) The sample probe must be exposed to the same ambient temperature as the primary device. The operator may accomplish this by physically locating the sample probe in the same ambient temperature conditions as the primary device (such as in a heated meter house) or by installing insulation and/or heat tracing along the entire meter run. If the operator chooses to use insulation to comply with this requirement, the AO may prescribe the quality of the insulation based on site specific factors such as ambient temperature, flowing temperature of the gas, composition of the gas, and location of the sample probe in relation to the orifice plate (i.e., inside or outside of a meter house).

(c) Sample probe design and type. (1) Sample probes must be constructed from stainless steel.

(2) If a regulating type of sample probe is used, the pressure-regulating mechanism must be inside the pipe or maintained at a temperature of at least 30° F above the hydrocarbon dew point of the gas.

(3) The sample probe length must be the shorter of:

(i) The length necessary to place the collection end of the probe in the center one third of the pipe cross-section; or

(ii) The recommended length of the probe in Table 1 in API 14.1, Subsection 6.4 (incorporated by reference, see § 3175.30).

(4) The use of membranes, screens, or filters at any point in the sample probe is prohibited.

(d) Sample tubing connecting the sample probe to the sample container or analyzer must be constructed of stainless steel or nylon 11.

§ 3175.113 Spot samples – general requirements.

(a) If an FMP is not flowing at the time that a sample is due, a sample must be taken within 15 days after flow is re-initiated. Documentation of the non-flowing status of the FMP must be entered into GARVS as required under § 3175.120(f).

(b) The operator must notify the AO at least 72 hours before obtaining a spot sample as required by this subpart, or submit a monthly or quarterly schedule of spot samples to the AO in advance of taking samples.

(c) Sample cylinder requirements. Sample cylinders must:

(1) Comply with API 14.1, Subsection 9.1 (incorporated by reference, see § 3175.30);

(2) Have a minimum capacity of 300 cubic centimeters; and

(3) Be cleaned before sampling under GPA 2166-05, Appendix A (incorporated by reference, see § 3175.30), or an equivalent method. The operator must maintain documentation of cleaning (see § 3170.7), have the documentation available on site during sampling, and provide it to the BLM upon request.

(d) Spot sampling using portable gas chromatographs. (1) Sampling separators, if used, must:

(i) Be constructed of stainless steel;

(ii) Be cleaned under GPA 2166-05, Appendix A (incorporated by reference, see § 3175.30), or an equivalent method, prior to sampling. The operator must maintain documentation of cleaning (see § 3170.7), have the documentation available on site during sampling, and provide it to the BLM upon request; and

(iii) Be operated under GPA 2166-05, Appendix B.3 (incorporated by reference, see § 3175.30).

(2) The sample port and inlet to the sample line must be purged using the gas being sampled before completing the connection between them.

(3) The portable GC must be operated, verified, and calibrated under § 3175.118.

(4) The documentation of verification or calibration required in § 3175.118(d) must be available for inspection by the BLM at the time of sampling.

(5) Minimum number of samples and analyses. (i) For low- and very-low-volume FMPs, at least three samples must be taken and analyzed;

(ii) For high-volume FMPs, samples must be taken and analyzed until the difference between the maximum heating value and minimum heating value calculated from three consecutive analyses is less than or equal to 16 Btu/scf;

(iii) For very-high-volume FMPs, samples must be taken and analyzed until the difference between the maximum heating value and minimum heating value calculated from three consecutive analyses is less than or equal to 8 Btu/scf.

(6) The heating value and relative density used for OGOR reporting must be:

(i) The mean heating value and relative density calculated from the three analyses required in paragraph (d)(5) of this section;

(ii) The median heating value and relative density calculated from the three analyses required in paragraph (d)(5) of this section; or

(iii) Any other method approved by the BLM.

§ 3175.114 Spot samples – allowable methods.

(a) Spot samples must be obtained using one of the following methods:

(1) Purging - fill and empty method. Samples taken using this method must comply with GPA 2166-05, Section 9.1 (incorporated by reference, see § 3175.30);

(2) Helium "pop" method. Samples taken using this method must comply with GPA 2166-05, Section 9.5 (incorporated by reference, see § 3175.30). The operator must maintain documentation demonstrating that the cylinder was evacuated and pre-charged before sampling and make the documentation available to the AO upon request;

(3) Floating piston cylinder method. Samples taken using this method must comply with GPA 2166-05, Sections 9.7.1 to 9.7.3 (incorporated by reference, see § 3175.30). The operator must maintain documentation of the seal material and type of lubricant used and make the documentation available to the AO upon request;

(4) Portable gas chromatograph. Samples taken using this method must comply with § 3175.118; or

(5) Other methods approved by the BLM (through the PMT) and posted at www.blm.gov.

(b) If the operator uses either a purging - fill and empty method or a helium "pop" method, and if the flowing pressure at the sample port is less than or equal to 15 psig, the operator may also employ a vacuum-gathering system. Samples taken using a vacuum-gathering system must comply with API 14.1, Subsection 11.10 (incorporated by reference, see § 3175.30), and the samples must be obtained from the discharge of the vacuum pump.

§ 3175.115 Spot samples - frequency.

(a) Unless otherwise required under paragraph (b) of this section, spot samples for all FMPs must be taken and analyzed at the frequency (once during every period, stated in months) prescribed in Table 1 to § 3175.110.

(b) After the time frames listed in paragraph (b)(1) of this section, the BLM may change the required sampling frequency for high-volume and very-high-volume FMPs if the BLM determines that the sampling frequency required in Table 1 in § 3175.110 is not sufficient to achieve the heating value uncertainty levels required in § 3175.31(b).

(1) Timeframes for implementation. (i) For high-volume FMPs, the BLM may change the sampling frequency no sooner than 2 years after the FMP begins measuring gas or January 19, 2021, whichever is later; and

(ii) For very-high-volume FMPs, the BLM may change the sampling frequency or require compliance with paragraph (b)(5) of this section no sooner than 1 year after the FMP begins measuring gas or January 17, 2020, whichever is later.

(2) The BLM will calculate the new sampling frequency needed to achieve the heating value uncertainty levels required in § 3175.31(b). The BLM will base the sampling frequency calculation on the heating value variability. The BLM will notify the operator of the new sampling frequency.

(3) The new sampling frequency will remain in effect until the heating value variability justifies a different frequency.

(4) The new sampling frequency will not be more frequent than once every 2 weeks nor less frequent than once every 6 months.

(5) For very-high-volume FMPs, the BLM may require the installation of a composite sampling system or on-line GC if the heating value uncertainty levels in § 3175.31(b) cannot be achieved through spot sampling. Composite sampling systems or on-line gas chromatographs that are installed and operated in accordance with this section comply with the uncertainty requirement of § 3175.31(b)(2).

(c) The time between any two samples must not exceed the timeframes shown in Table 1 to this section.

<u>Table 1 to § 3175.115</u>: Maximum Time Between Samples

Maximum Time Between Samples	
If the required sampling frequency is once during every:	Then the maximum time between samples (in days) is:
2 weeks	18
Month	45
2 months	75
3 months	105
6 months	195

12 months	380

(d) If a composite sampling system or an on-line GC is installed under § 3175.116 or § 3175.117, either on the operator’s own initiative or in response to a BLM order for a very-high-volume FMP under paragraph (b)(5) of this section, it must be installed and operational no more than 30 days after the due date of the next sample.

(e) The required sampling frequency for an FMP at which a composite sampling system or an on-line gas chromatograph is removed from service is prescribed in paragraph (a) of this section.

§ 3175.116 Composite sampling methods.

(a) Composite samplers must be flow-proportional.

(b) Samples must be collected using a positive-displacement pump.

(c) Sample cylinders must be sized to ensure the cylinder capacity is not exceeded within the normal collection frequency.

§ 3175.117 On-line gas chromatographs.

(a) On-line GCs must be installed, operated, and maintained under GPA 2166-05, Appendix D (incorporated by reference, see § 3175.30), and the manufacturer’s specifications, instructions, and recommendations.

(b) The GC must comply with the verification and calibration requirements of § 3175.118. The results of all verifications must be submitted to the AO upon request.

(c) Upon request, the operator must submit to the AO the manufacturer’s specifications and installation and operational recommendations.

§ 3175.118 Gas chromatograph requirements.

(a) All GCs must be installed, operated, and calibrated under GPA 2261-13 (incorporated by reference, see § 3175.30).

(b) Samples must be analyzed until the un-normalized sum of the mole percent of all gases analyzed is between 97 and 103 percent.

(c) A GC may not be used to analyze any sample from an FMP until the verification meets the standards of this paragraph (c).

(1) GCs must be verified under GPA 2261-13, Section 6 (incorporated by reference, see § 3175.30), not less than once every 7 days.

(2) All gases used for verification and calibration must meet the standards of GPA 2198-03, Sections 3 and 4 (incorporated by reference, see § 3175.30).

(3) All new gases used for verification and calibration must be authenticated prior to verification or calibration under the standards of GPA 2198-03, Section 5 (incorporated by reference, see § 3175.30).

(4) The gas used to calibrate a GC must be maintained under Section 6 of GPA 2198-03 (incorporated by reference, see § 3175.30).

(5) If the composition of the gas used for verification as determined by the GC varies from the certified composition of the gas used for verification by more than the reproducibility values listed in GPA 2261-13, Section 10 (incorporated by reference, see § 3175.30), the GC must be calibrated under GPA 2261-13, Section 6 (incorporated by reference, see § 3175.30).

(6) If the GC is calibrated, it must be re-verified under paragraph (c)(5) of this section.

(d) The operator must retain documentation of the verifications for the period required under § 3170.6 of this part, and make it available to the BLM upon request. The documentation must include:

(1) The components analyzed;

(2) The response factor for each component;

(3) The peak area for each component;

(4) The mole percent of each component as determined by the GC;

(5) The mole percent of each component in the gas used for verification;

(6) The difference between the mole percents determined in paragraphs (d)(4) and (5) of this section, expressed in relative percent;

(7) Evidence that the gas used for verification and calibration:

(i) Meets the requirements of paragraph (c)(2) of this section, including a unique identification number of the calibration gas used, the name of the supplier of the calibration gas, and the certified list of the mole percent of each component in the calibration gas;

(ii) Was authenticated under paragraph (c)(3) of this section prior to verification or calibration, including the fidelity plots; and

(iii) Was maintained under paragraph (c)(4) of this section, including the fidelity plot made as part of the calibration run;

(8) The chromatograms generated during the verification process;

(9) The time and date the verification was performed; and

(10) The name and affiliation of the person performing the verification.

(e) Extended analyses must be taken in accordance with GPA 2286-14 (incorporated by reference, see § 3175.30) or other method approved by the BLM.

§ 3175.119 Components to analyze.

(a) The gas must be analyzed for the following components:

(1) Methane;

(2) Ethane;

(3) Propane;

(4) Iso Butane;

(5) Normal Butane;

(6) Pentanes;

(7) Hexanes + (C_6+);

(8) Carbon dioxide; and

(9) Nitrogen.

(b) When the concentration of C_6+ exceeds 0.5 mole percent, the following gas components must also be analyzed:

(1) Hexanes;

(2) Heptanes;

(3) Octanes; and

(4) Nonanes +.

(c) In lieu of testing each sample for the components required under paragraph (b) of this section, the operator may periodically test for these components and adjust the assumed C_6+ composition to remove bias in the heating value (see § 3175.126(a)(3)). The C_6+ composition must be applied to the mole percent of C_6+ analyses until the next analysis is done under paragraph (b) of this section. The minimum analysis frequency for the components listed in paragraph (b) of this section is as follows:

(1) For high-volume FMPs, once per year; and

(2) For very-high-volume FMPs, once every 6 months.

§ 3175.120 Gas analysis report requirements.

(a) The gas analysis report must contain the following information:

(1) The information required in § 3170.7(g) of this part;

(2) The date and time that the sample for spot samples was taken or, for composite samples, the date the cylinder was installed and the date the cylinder was removed;

(3) The date and time of the analysis;

(4) For spot samples, the effective date, if other than the date of sampling;

(5) For composite samples, the effective start and end date;

(6) The name of the laboratory where the analysis was performed;

(7) The device used for analysis (i.e., GC, calorimeter, or mass spectrometer);

(8) The make and model of analyzer;

(9) The date of last calibration or verification of the analyzer;

(10) The flowing temperature at the time of sampling;

(11) The flowing pressure at the time of sampling, including units of measure (psia or psig);

(12) The flow rate at the time of sampling;

(13) The ambient air temperature at the time of sampling;

(14) Whether or not heat trace or any other method of heating was used;

(15) The type of sample (i.e., spot-cylinder, spot-portable GC, composite);

(16) The sampling method if spot-cylinder (e.g., fill and empty, helium pop);

(17) A list of the components of the gas tested;

(18) The un-normalized mole percents of the components tested, including a summation of those mole percents;

(19) The normalized mole percent of each component tested, including a summation of those mole percents;

(20) The ideal heating value (Btu/scf);

(21) The real heating value (Btu/scf), dry basis;

(22) The hexane+ split, if applicable;

(23) The pressure base and temperature base;

(24) The relative density; and

(25) The name of the company obtaining the gas sample.

(b) Components that are listed on the analysis report, but not tested, must be annotated as such.

(c) The heating value and relative density must be calculated under API 14.5 (incorporated by reference, see § 3175.30).

(d) The base supercompressibility must be calculated under AGA Report No. 8 (incorporated by reference, see § 3175.30).

(e) The operator must submit all gas analysis reports to the BLM within 15 days of the due date for the sample as specified in § 3175.115.

(f) Unless a variance is granted, the operator must submit all gas analysis reports and other required related information electronically through the GARVS. The BLM will grant a variance to the electronic-submission requirement only in cases where the operator demonstrates that it is a small business, as defined by the U.S. Small Business Administration, and does not have access to the Internet.

§ 3175.121 Effective date of a spot or composite gas sample.

(a) Unless otherwise specified on the gas analysis report, the effective date of a spot sample is the date on which the sample was taken.

(b) The effective date of a spot gas sample may be no later than the first day of the production month following the operator's receipt of the laboratory analysis of the sample.

(c) Unless otherwise specified on the gas analysis report, the effective date of a composite sample is the first of the month in which the sample was removed.

(d) The provisions of this section apply only to OGORs, QTRs, and gas sample reports generated after [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER].

§ 3175.125 Calculation of heating value and volume

(a) The heating value of the gas sampled must be calculated as follows:

(1) Gross heating value is defined by API 14.5, Subsection 3.7 (incorporated by reference, see § 3175.30) and must be calculated under API 14.5, Subsection 7.1 (incorporated by reference, see § 3175.30); and

(2) Real heating value must be calculated by dividing the gross heating value of the gas calculated under paragraph (a)(1) of this section by the compressibility factor of the gas at 14.73 psia and 60° F.

(b) Average heating value determination. (1) If a lease, unit PA, or CA has more than one FMP, the average heating value for the lease, unit PA, or CA for a reporting month must be the volume-weighted average of heating values, calculated as follows:

$$\overline{HV} = \frac{\sum_{i=1}^{i=n}\left(HV_i \times V_i\right)}{\sum_{i=1}^{i=n} V_i}$$

Where:

$\overline{HV}$ = the average heating value for the lease, unit PA, or CA, for the reporting month, in Btu/scf
HV_i = the heating value for FMP_i, during the reporting month (see § 3175.120(b)(2) if an FMP has multiple heating values during the reporting month), in Btu/scf
V_i = the volume measured by FMPi, during the reporting month, in Btu/scf
Subscript i represents each FMP for the lease, unit PA, or CA
n = the number of FMPs for the lease, unit PA, or CA

(2) If the effective date of a heating value for an FMP is other than the first day of the reporting month, the average heating value of the FMP must be the volume-weighted average of heating values, determined as follows:

$$HV_i = \frac{\sum_{j=1}^{j=m}\left(HV_{i,j} \times V_{i,j}\right)}{\sum_{j=1}^{j=m} V_{i,j}}$$

Where:

HV_i = the heating value for FMP_i, in Btu/scf
$HV_{i,j}$ = the heating value for FMP_i, for partial month j, in Btu/scf
$V_{i,j}$ = the volume measured by FMP_i, for partial month j, in Btu/scf
Subscript i represents each FMP for the lease, unit PA, or CA
Subscript j represents a partial month for which heating value $HV_{i,j}$ is effective

m = the number of different heating values in a reporting month for an FMP

(c) The volume must be determined under § 3175.94 (mechanical recorders) or § 3175.103(c) (EGM systems).

§ 3175.126 Reporting of heating value and volume.

(a) The gross heating value and real heating value, or average gross heating value and average real heating value, as applicable, derived from all samples and analyses must be reported on the OGOR in units of Btu/scf under the following conditions:

(1) Containing no water vapor ("dry"), unless the water vapor content has been determined through actual on-site measurement and reported on the gas analysis report. The heating value may not be reported on the basis of an assumed water-vapor content. Acceptable methods of measuring water vapor are:

(i) Chilled mirror;

(ii) Laser detectors; and

(iii) Other methods approved by the BLM;

(2) Adjusted to a pressure of 14.73 psia and a temperature of 60° F; and

(3) For samples analyzed under § 3175.119(a), and notwithstanding any provision of a contract between the operator and a purchaser or transporter, the composition of hexane+ is deemed to be:

(i) 60 percent n-hexane, 30 percent n-heptane, and 10 percent n-octane; or

(ii) The composition determined under § 3175.119(c).

(b) The volume for royalty purposes must be reported on the OGOR in units of Mcf as follows:

(1) The volume must not be adjusted for water-vapor content or any other factors that are not included in the calculations required in § 3175.94 or § 3175.103; and

(2) The volume must match the monthly volume(s) shown in the unedited QTR(s) or integration statement(s) unless edits to the data are documented under paragraph (c) of this section.

(c) Edits and adjustments to reported volume or heating value. (1) If for any reason there are measurement errors stemming from an equipment malfunction that results in discrepancies to the calculated volume or heating value of the gas, the volume or heating value reported during the period in which the volume or heating value error persisted must be estimated.

(2) All edits made to the data before the submission of the OGOR must be documented and include verifiable justifications for the edits made. This documentation must be maintained under § 3170.7 of this part and must be submitted to the BLM upon request.

(3) All values on daily and hourly QTRs that have been changed or edited must be clearly identified and must be cross referenced to the justification required in paragraph (c)(2) of this section.

(4) The volumes reported on the OGOR must be corrected beginning with the date that the inaccuracy occurred. If that date is unknown, the volumes must be corrected beginning with the production month that includes the date that is half way between the date of the previous verification and the most recent verification date.

§ 3175.130 Transducer testing protocol.

The BLM will approve a particular make, model, and range of differential-pressure, static-pressure, or temperature transducer for use in an EGM system only if the testing performed on the transducer met all of the standards and requirements stated in §§ 3175.131 through 3175.135.

§ 3175.131 General requirements for transducer testing.

(a) All testing must be performed by a qualified test facility.

(b) Number and selection of transducers tested. (1) A minimum of five transducers of the same make, model, and URL, selected at random from the stock used to supply normal field operations, must be type-tested.

(2) The serial number of each transducer selected must be documented. The date, location, and batch identifier, if applicable, of manufacture must be ascertainable from the serial number.

(3) For the purpose of this section, the term “model” refers to the base model number on which the BLM determines the transducer performance. For example: A manufacturer makes a transmitter with a model number 1234-XYZ, where “1234” identifies the transmitter cell, “X” identifies the output type, “Y” identifies the mounting type, and “Z” identifies where the static pressure is taken. The testing under this section would only be required on the base model number (“1234”), assuming that “X”, “Y”, or “Z” does not affect the performance of the transmitter.

(4) For multi-variable transducers, each cell URL must be tested only once under this section. For example: A manufacturer of a transducer measuring both differential and static pressure makes a model with available differential-pressure URLs of 100 inches, 500 inches, and 1,000 inches, and static-pressure URLs of 250 psia, 1,000 psia, and 2,500 psia. Although there are nine possible combinations of differential-pressure and static-pressure URLs, only six tests are required to cover each cell URL.

(c) Test conditions – general. The electrical supply must meet the following minimum tolerances:

(1) Rated voltage: ±1 percent uncertainty;

(2) Rated frequency: ±1 percent uncertainty;

(3) Alternating current harmonic distortion: Less than 5 percent; and

(4) Direct current ripple: Less than 0.10 percent uncertainty.

(d) The input and output (if the output is analog) of each transducer must be measured with equipment that has a published reference uncertainty less than or equal to 25 percent of the published reference uncertainty of the transducer under test across the measurement range common to both the transducer under test and the test instrument. Reference uncertainty for both the test instrument and the transducer under test must be expressed in the units the transducer measures to determine acceptable uncertainty. For example, if the transducer under test has a published reference uncertainty of ±0.05 percent of span, and a span of 0 to 500 psia, then this transducer has a reference accuracy of ±0.25 psia (0.05 percent of 500 psia). To meet the requirements of this paragraph (d), the test instrument in this example must have an uncertainty of ±0.0625 psia or less (25 percent of ±0.25 psia).

(e) If the manufacturer's performance specifications for the transducer under test include corrections made by an external device (such as linearization), then the external device must be tested along with the transducer and be connected to the transducer in the same way as in normal field operations.

(f) If the manufacturer specifies the extent to which the measurement range of the transducer under test may be adjusted downward (i.e., spanned down), then each test required in §§ 3175.132 and 3175.133 must be carried out at least at both the URL and the minimum upper calibrated limit specified by the manufacturer. For upper calibrated limits between the maximum and the minimum span that are not tested, the BLM will use the greater of the uncertainties measured at the maximum and minimum spans in determining compliance with the requirements of § 3175.31(a).

(g) After initial calibration, no calibration adjustments to the transducer may be made until all required tests in §§ 3175.132 and 3175.133 are completed.

(h) For all of the testing required in §§ 3175.132 and 3175.133, the term “tested for accuracy” means a comparison between the output of the transducer under test and the test equipment taken as follows:

(1) The following values must be tested in the order shown, expressed as a percent of the transducer span:

(i) (Ascending values) 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, and 100; and

(ii) (Descending values) 100, 90, 80, 70, 60, 50, 40, 30, 20, 10, and 0.

(2) If the device under test is an absolute-pressure transducer, the “0” values listed in paragraphs (h)(1)(i) and (ii) of this section must be replaced with “atmospheric pressure at the test facility;”

(3) Input approaching each required test point must be applied asymptotically without overshooting the test point;

(4) The comparison of the transducer and the test equipment measurements must be recorded at each required point; and

(5) For static-pressure transducers, the following test point must be included for all tests:

(i) For gauge-pressure transducers, a gauge pressure of -5 psig; and

(ii) For absolute-pressure transducers, an absolute pressure of 5 psia.

§ 3175.132 Testing of reference accuracy.

(a) The following reference test conditions must be maintained for the duration of the testing:

(1) Ambient air temperature must be between 59° F and 77° F and must not vary over the duration of the test by more than ±2° F;

(2) Relative humidity must be between 45 percent and 75 percent and must not vary over the duration of the test by more than ±5 percent;

(3) Atmospheric pressure must be between 12.46 psi and 15.36 psi and must not vary over the duration of the test by more than ±0.2 psi;

(4) The transducer must be isolated from any externally induced vibrations;

(5) The transducer must be mounted according to the manufacturer’s specifications in the same manner as it would be mounted in normal field operations;

(6) The transducer must be isolated from any external electromagnetic fields; and

(7) For reference accuracy testing of differential-pressure transducers, the downstream side of the transducer must be vented to the atmosphere.

(b) Before reference testing begins, the following pre-conditioning steps must be followed:

(1) After power is applied to the transducer, it must be allowed to stabilize for at least 30 minutes before applying any input pressure or temperature;

(2) The transducer must be exercised by applying three full-range traverses in each direction; and

(3) The transducer must be calibrated according to manufacturer specifications if a calibration is required or recommended by the manufacturer.

(c) Immediately following preconditioning, the transducer must be tested at least three times for accuracy under § 3175.131(h). The results of these tests must be used to determine the transducer's reference accuracy under § 3175.135.

§ 3175.133 Testing of influence effects.

(a) General requirements. (1) Reference conditions (see § 3175.132), with the exception of the influence effect being tested under this section, must be maintained for the duration of these tests.

(2) After completing the required tests for each influence effect under this section, the transducer under test must be returned to reference conditions and tested for accuracy under § 3175.132.

(b) Ambient temperature. (1) The transducer's accuracy must be tested at the following temperatures (^{0} F): +68, +104, +140, + 68, 0, -4, -40, +68.

(2) The ambient temperature must be held to ±4° F from each required temperature during the accuracy test at each point.

(3) The rate of temperature change between tests must not exceed 2° F per minute.

(4) The transducer must be allowed to stabilize at each test temperature for at least 1 hour.

(5) For each required temperature test point listed in this paragraph, the transducer must be tested for accuracy under § 3175.131(h).

(c) Static-pressure effects (differential-pressure transducers only). (1) For single-variable transducers, the following pressures must be applied equally to both sides of the transducer, expressed in percent of maximum rated working pressure: 0, 50, 100, 75, 25, 0.

(2) For multivariable transducers, the following pressures must be applied equally to both sides of the transducer, expressed in percent of the URL of the static-pressure transducer: 0, 50, 100, 75, 25, 0.

(3) For each point required in paragraphs (c)(1) and (2) of this section, the transducer must be tested for accuracy under § 3175.131(h).

(d) <u>Mounting position effects</u>. The transducer must be tested for accuracy at four different orientations under § 3175.131(h) as follows:

(1) At an angle of -10° from a vertical plane;

(2) At an angle of +10° from a vertical plane;

(3) At an angle of -10° from a vertical plane perpendicular to the vertical plane required in paragraphs (d)(1) and (2) of this section; and

(4) At an angle of +10° from a vertical plane perpendicular to the vertical plane required in paragraphs (d)(1) and (2) of this section.

(e) <u>Over-range effects</u>. (1) A pressure of 150 percent of the URL, or to the maximum rated working pressure of the transducer, whichever is less, must be applied for at least 1 minute.

(2) After removing the applied pressure, the transducer must be tested for accuracy under § 3175.131(h).

(3) No more than 5 minutes must be allowed between performing the procedures described in paragraphs (e)(1) and (2) of this section.

(f) Vibration effects. (1) An initial resonance test must be conducted by applying the following test vibrations to the transducer along each of the three major axes of the transducer while measuring the output of the transducer with no pressure applied:

(i) The amplitude of the applied test frequency must be at least 0.35mm below 60 Hertz (Hz) and 49 meter per second squared (m/s^2) above 60 Hz; and

(ii) The applied frequency must be swept from 10 Hz to 2,000 Hz at a rate not greater than 0.5 octaves per minute.

(2) After the initial resonance search, an endurance conditioning test must be conducted as follows:

(i) Twenty frequency sweeps from 10 Hz to 2,000 Hz to 10 Hz must be applied to the transducer at a rate of 1 octave per minute, repeated for each of the 3 major axes; and

(ii) The measurement of the transducer's output during this test is unnecessary.

(3) A final resonance test must be conducted under paragraph (f)(1) of this section.

§ 3175.134 Transducer test reporting.

(a) Each test required by §§ 3175.131 through 3175.133 must be fully documented by the test facility performing the tests. The report must indicate the results for each required test and include all data points recorded.

(b) The report must be submitted to the PMT. If the PMT determines that all testing was completed as required by §§ 3175.131 through 3175.133, it will make a recommendation that the BLM approve the transducer make, model, and range, along with the reference uncertainty, influence effects, and any operating restrictions, and posts them to the BLM's website at www.blm.gov as an approved device.

§ 3175.135 Uncertainty determination.

(a) Reference uncertainty calculations for each transducer of a given make, model, URL, and turndown must be determined as follows (the result for each transducer is denoted by the subscript i):

(1) Maximum error (E_i). The maximum error for each transducer is the maximum difference between any input value from the test device and the corresponding output from the transducer under test for any required test point, and must be expressed in percent of transducer span.

(2) Hysteresis (H_i). The testing required in § 3175.132 requires at least three pairs of tests using both ascending test points (low to high) and descending test points (high to low) of the same value. Hysteresis is the maximum difference between the ascending value and the descending value for any single input test value of a test pair. Hysteresis must be expressed in percent of span.

(3) Repeatability (R_i). The testing required under § 3175.132 requires at least three pairs of tests using both ascending test points (low to high) and descending test points (high to low) of the same value. Repeatability is the maximum difference between the value of any of the three ascending test points for a given input value or of the three descending test points for a given value. Repeatability must be expressed in percent of span.

(b) Reference uncertainty of a transducer. The reference uncertainty of each transducer of a given make, model, URL, and turndown ($U_{r,i}$) must be determined as follows:

$$U_{r,i} = \sqrt{E_i^2 + H_i^2 + R_i^2}$$

Where E_i, H_i, and R_i, are described in paragraph (a) of this section. Reference uncertainty is expressed in percent of span.

(c) Reference uncertainty for the make, model, URL, and turndown of a transducer (U_r) must be determined as follows:

$$U_r = \sigma \times t_{dist}$$

Where:

σ = the standard deviation of the reference uncertainties determined for each transducer ($U_{r,i}$)

t_{dist} = the "t-distribution" constant as a function of degrees of freedom (n-1) and at a 95 percent confidence level, where n = the number of transducers of a specific make, model, URL, and turndown tested (minimum of 5)

(d) Influence effects. The uncertainty from each influence effect required to be tested under § 3175.133 must be determined as follows:

(1) Zero-based errors of each transducer. Zero-based errors from each influence test must be determined as follows:

$$E_{zero,n,i} = \frac{\Delta Z_{n,i}}{span \times M_n} \times 100$$

Where:

subscript i represents the results for each transducer tested of a given make, model, URL, and turndown

subscript n represents the results for each influence effect test required under § 3175.133

$E_{zero,n,i}$ = Zero-based error for influence effect n, for transducer i, in percent of span per increment of influence effect

M_n = the magnitude of influence effect n (e.g., 1,000 psi for static-pressure effects, 50° F for ambient temperature effects)

And:

$$\Delta Z_{n,i} = Z_{n,i} - Z_{ref,i}$$

Where:

$Z_{n,i}$ = the average output from transducer i with zero input from the test device, during the testing of influence effect n

$Z_{ref,i}$ = the average output from transducer i with zero input from the test device, during reference testing.

(2) Span-based errors of each transducer. Span-based errors from each influence effect must be determined as follows:

$$E_{span,n,i} = \left(\frac{S_{n,i} - \Delta Z_{n,i}}{span} - 1 \right) \times \frac{100}{M_n}$$

Where:

$E_{span,n,i}$ = Span-based error for influence effect n, for transducer i, in percent of reading per increment of influence effect

$S_{n,i}$ = the average output from transducer i, with full span applied from the test device, during the testing for influence effect n.

(3) Zero- and span-based errors due to influence effects for a make, model, URL, and turndown of a transducer must be determined as follows:

$$E_{z,n} = \sigma_{z,n} \times t_{dist}$$

$$E_{s,n} = \sigma_{s,n} \times t_{dist}$$

Where:

$E_{z,n}$ = the zero-based error for a make, model, URL, and turndown of transducer, for influence effect n, in percent of span per unit of magnitude for the influence effect

$E_{s,n}$ = the span-based error for a make, model, URL, and turndown of transducer, for influence effect n, in percent of reading per unit of magnitude for the influence effect

$\sigma_{z,n}$ = the standard deviation of the zero-based differences from the influence effect tests under § 3175.133 and the reference uncertainty tests, in percent

$\sigma_{s,n}$ = the standard deviation of the span-based differences from the influence effect tests under § 3175.133 and the reference uncertainty tests, in percent

t_{dist} = the "t-distribution" constant as a function of degrees of freedom (n-1) and at a 95 percent confidence level, where n = the number of transducers of a specific make, model, URL, and turndown tested (minimum of 5).

§ 3175.140 Flow-computer software testing.

The BLM will approve a particular version of flow-computer software for use in a specific make and model of flow computer only if the testing performed on the software meets all of the standards and requirements in §§ 3175.141 through 3175.144. Type-testing is required for each software version that affects the calculation of flow rate, volume, heating value, live input variable averaging, flow time, or the integral value. Software updates or changes that do not affect these items do not require BLM approval.

§ 3175.141 General requirements for flow-computer software testing.

(a) Test facility. All testing must be performed by a qualified test facility not affiliated with the flow-computer manufacturer.

(b) Selection of flow-computer software to be tested. (1) Each software version tested must be identical to the software version installed at FMPs for normal field operations.

(2) Each software version must have a unique identifier.

(c) Testing method. Input variables may be either:

(1) Applied directly to the hardware registers; or

(2) Applied physically to a transducer. If input variables are applied physically to a transducer, the values received by the hardware registers from the transducer must be recorded.

(d) Pass-fail criteria. (1) For each test listed in §§ 3175.142 and 3175.143, the value(s) required to be calculated by the software version under test must be compared to the value(s) calculated by BLM-approved reference software, using the same digital input for both.

(2) The software under test may be used at an FMP only if the difference between all values calculated by the software version under test and the reference software is less than 50 parts per million (0.005 percent) and the results of the tests required in §§ 3175.142 and 3175.143 are satisfactory to the PMT. If the test results are satisfactory, the BLM will identify the software version tested as acceptable for use on its website at www.blm.gov.

§ 3175.142 Required static tests.

(a) Instantaneous flow rate. The instantaneous flow rates must meet the criteria in § 3175.141(d) for each test identified in Table 1 to this section, using the gas compositions identified in Table 2 to this section, as prescribed in Table 1 to this section.

Table 1 to § 3175.142: Required Inputs for Static Testing

Required Inputs for Static Testing							
Test	Pipe inside diameter (inches)	Orifice diameter (inches)	Differential pressure (inches of water)	Static pressure (psia)	Flowing temperature (° F)	Composition (see Table 2 to § 3175.142)	Static Tap location
1	2.067	0.500	1	15	40	Table 2, Column 1	Up
2		1.500	800	140	80	Table 2, Column 2	Down
3	6.065	1.000	100	1000	-40	Table 2, Column 1	Up
4		4.000	50	500	150	Table 2, Column 1	Down
5	4.026	1.000	100	1000	-40	Table 2, Column 2	Down
6		3.000	50	500	150	Table 2, Column 2	Up

Table 2 to § 3175.142: Required Compositions for Static Testing

Required Compositions for Static Testing		
Component	Composition (mole percent)	
	Composition Column 1	Composition Column 2
Methane	92.0000	76.0000
Ethane	3.3000	8.3000
Propane	1.5000	3.6000
i-Butane	0.4900	0.9000
n-Butane	0.3600	1.5000
i-Pentane	0.4000	1.0000
n-Pentane	0.3000	0.5000
n-Hexane	0.3000	0.8000
n-Heptane	0.2000	0.3000
n-Octane	0.1000	0.2000
n-Nonane	0.0500	0.1000
Carbon dioxide	0.8000	5.3000
Nitrogen	0.2000	1.4000
Helium	0.0000	0.0500
Oxygen	0.0000	0.0300
Hydrogen sulfide	0.0000	0.0200

(b) Sums and averages. (1) Fixed input values from test 2 in Table 1 to this section must be applied for a period of at least 24 hours.

(2) At the conclusion of the 24-hour period, the following hourly and daily values must meet the criteria in § 3175.141(d):

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(c) Other tests. The following additional tests must be performed on the flow-computer software:

(1) Each parameter of the configuration log must be changed to ensure the event log properly records the changes according to the variables listed in § 3175.104(c); and

(2) Inputs simulating a 15 percent and 150 percent over-range of the differential and static-pressure transducer's calibrated span must be entered to verify that the over-range condition triggers an alarm or an entry in the event log.

§ 3175.143 Required dynamic tests.

(a) Square wave test. The pressures and temperatures must be applied to the software revision under test for at least 60 minutes as follows:

(1) Differential pressure. The differential pressure must be cycled from a low value, below the no-flow cutoff, to a high value of approximately 80 percent of the upper calibrated limit of the differential-pressure transducer. The cycle must approximate a square wave pattern with a period of 60 seconds, and the maximum and minimum values must be the same for each cycle;

(2) Static pressure. The static pressure must be cycled between approximately 20 percent and approximately 80 percent of the upper calibrated limit of the static-pressure transducer in a square wave pattern identical to the cycling pattern used for the differential pressure. The maximum and minimum values must be the same for each cycle;

(3) Temperature. The temperature must be cycled between approximately 20° F and approximately 100° F in a square wave pattern identical to the cycling pattern used for

the differential pressure. The maximum and minimum values must be the same for each cycle; and

(4) At the conclusion of the 1-hour period, the following hourly values must meet the criteria in § 3175.141(d):

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(b) Sawtooth test. The pressures and temperatures must be applied to the software revision under test for 24 hours as follows:

(1) Differential pressure. The differential pressure must be cycled from a low value, below the no-flow cutoff, to a high value of approximately 80 percent of the maximum value of differential pressure for which the flow computer is designed. The cycle must approximate a linear sawtooth pattern between the low value and the high value and there must be 3 to 10 cycles per hour. The no-flow period between cycles must last approximately 10 percent of the cycle period;

(2) Static pressure. The static pressure must be cycled between approximately 20 percent and approximately 80 percent of the maximum value of static pressure for which the flow computer is designed. The cycle must approximate a linear sawtooth pattern between the low value and the high value and there must be 3 to 10 cycles per hour;

(3) Temperature. The temperature must be cycled between approximately 20° F and approximately 100° F. The cycle should approximate a linear sawtooth pattern between the low value and the high value and there must be 3 to 10 cycles per hour; and

(4) At the conclusion of the 24-hour period, the following hourly and daily values must meet the criteria in § 3175.141(d):

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(c) Random test. The pressures and temperatures must be applied to the software revision under test for 24 hours as follows:

(1) Differential pressure. Differential-pressure random values must range from a low value, below the no-flow cutoff, to a high value of approximately 80 percent of the upper calibrated limit of the differential-pressure transducer. The no-flow period between cycles must last for approximately 10 percent of the test period;

(2) Static pressure. Static-pressure random values must range from a low value of approximately 20 percent of the upper calibrated limit of the static-pressure transducer, to a high value of approximately 80 percent of the upper calibrated limit of the static-pressure transducer;

(3) Temperature. Temperature random values must range from approximately 20° F to approximately 100° F; and

(4) At the conclusion of the 24-hour period, the following hourly values must meet the criteria in § 3175.141(d):

(i) Volume;

(ii) Integral value;

(iii) Flow time;

(iv) Average differential pressure;

(v) Average static pressure; and

(vi) Average flowing temperature.

(d) Long-term volume accumulation test. (1) Fixed inputs of differential pressure, static pressure, and temperature must be applied to the software version under test to simulate a flow rate greater than 500,000 Mcf/day for a period of at least 7 days.

(2) At the end of the 7-day test period, the accumulated volume must meet the criteria in § 3175.141(d).

§ 3175.144 Flow-computer software test reporting.

(a) The test facility performing the tests must fully document each test required by §§ 3175.141 through 3175.143. The report must indicate the results for each required test and include all data points recorded.

(b) The report must be submitted to the AO by the operator or the manufacturer. If the PMT determines all testing was completed as required by this section, it will make a recommendation that the BLM approve the software version and post it on the BLM's website at www.blm.gov as approved software.

§ 3175.150 Immediate assessments.

(a) Certain instances of noncompliance warrant the imposition of immediate assessments upon discovery. Imposition of any of these assessments does not preclude other appropriate enforcement actions.

(b) The BLM will issue the assessments for the violations listed as follows:

Table 1 to § 3175.150: Violations Subject to an Immediate Assessment

Violations Subject to an Immediate Assessment	
Violation:	Assessment amount per violation:
1. New FMP orifice plate inspections were not conducted as required by § 3175.80(c).	$1,000
2. Routine FMP orifice plate inspections were not conducted as required by § 3175.80(d).	$1,000
3. Basic meter-tube inspections were not conducted as required by § 3175.80(h).	$1,000
4. Detailed meter-tube inspections were not conducted as required by § 3175.80(i).	$1.000
5. An initial mechanical-recorder verification was not conducted as required by § 3175.92(a).	$1,000
6. Routine mechanical-recorder verifications were not conducted as required by § 3175.92(b).	$1,000
7. An initial EGM-system verification was not conducted as required by § 3175.102(a).	$1,000
8. Routine EGM-system verifications were not conducted as required by § 3175.102(b).	$1,000
9. Spot samples for low-volume and very-low-volume FMPs were not taken as required by § 3175.115(a).	$1,000
10. Spot samples for high- and very-high-volume FMPs were not taken as required by § 3175.115(a) and (b).	$1,000

Appendix A to Subpart 3175 – Table of Atmospheric Pressures

Elevation (ft msl)	Atmos. Pressure (psi)	Elevation (ft msl)	Atmos. Pressure (psi)	Elevation (ft msl)	Atmos. Pressure (psi)
0	14.70	**4,000**	12.70	**8,000**	10.92
100	14.64	4,100	12.65	8,100	10.88
200	14.59	4,200	12.60	8,200	10.84
300	14.54	4,300	12.56	8,300	10.80
400	14.49	4,400	12.51	8,400	10.76
500	14.43	4,500	12.46	8,500	10.72
600	14.38	4,600	12.42	8,600	10.68
700	14.33	4,700	12.37	8,700	10.63
800	14.28	4,800	12.32	8,800	10.59
900	14.23	4,900	12.28	8,900	10.55
1,000	14.17	**5,000**	12.23	**9,000**	10.51
1,100	14.12	5,100	12.19	9,100	10.47
1,200	14.07	5,200	12.14	9,200	10.43
1,300	14.02	5,300	12.10	9,300	10.39
1,400	13.97	5,400	12.05	9,400	10.35
1,500	13.92	5,500	12.01	9,500	10.31
1,600	13.87	5,600	11.96	9,600	10.27
1,700	13.82	5,700	11.92	9,700	10.23
1,800	13.77	5,800	11.87	9,800	10.19
1,900	13.72	5,900	11.83	9,900	10.15
2,000	13.67	**6,000**	11.78	**10,000**	10.12
2,100	13.62	6,100	11.74	10,100	10.08
2,200	13.57	6,200	11.69	10,200	10.04
2,300	13.52	6,300	11.65	10,300	10.00
2,400	13.47	6,400	11.61	10,400	9.96
2,500	13.42	6,500	11.56	10,500	9.92
2,600	13.37	6,600	11.52	10,600	9.88
2,700	13.32	6,700	11.48	10,700	9.84
2,800	13.27	6,800	11.43	10,800	9.81
2,900	13.22	6,900	11.39	10,900	9.77
3,000	13.17	**7,000**	11.35	**11,000**	9.73
3,100	13.13	7,100	11.30	11,100	9.69

3,200	13.08	7,200	11.26	11,200	9.65
3,300	13.03	7,300	11.22	11,300	9.62
3,400	12.98	7,400	11.18	11,400	9.58
3,500	12.93	7,500	11.13	11,500	9.54
3,600	12.89	7,600	11.09	11,600	9.50
3,700	12.84	7,700	11.05	11,700	9.47
3,800	12.79	7,800	11.01	11,800	9.43
3,900	12.74	7,900	10.97	11,900	9.39

ft msl = feet above mean sea level

Calculated as:

$$P_{atm} = 14.696 \times (1 - 0.00000686\ E)^{5.25577}$$

Where:

P_{atm} is atmospheric pressure, psi
E is meter elevation, feet above mean sea level

From: U.S. Standard Atmosphere, 1976, U.S. Government Printing Office, Washington, D.C., 1976.

[FR Doc. 2016-25410 Filed: 11/16/2016 8:45 am; Publication Date: 11/17/2016]