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Part IV

Department of the Interior

Minerals Management Service

30 CFR Parts 202, et al.

Royalties on Gas, Gas Analysis Reports, Oil and Gas Production Measurement, Surface Commingling, and Security; Final Rule

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Parts 202, 216, and 250

RIN 1010–AC23

Royalties on Gas, Gas Analysis Reports, Oil and Gas Production Measurement, Surface Commingling, and Security

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This final rule amends MMS's regulations governing oil and gas operations in the Outer Continental Shelf (OCS) to update production measurement, surface commingling, and security requirements. It also amends the standards for reporting and paying royalties on gas. MMS needs this rule to implement a system to verify that gas sales are reported accurately.

EFFECTIVE DATES: July 13, 1998. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of July 13, 1998.

FOR FURTHER INFORMATION CONTACT: Sharon Buffington, Engineering and Research Branch, at (703) 787–1147.

SUPPLEMENTARY INFORMATION: On February 26, 1997, MMS published the proposed rule for 30 CFR part 250, Subpart L in the **Federal Register** (62 FR 8665). During the 90-day comment period that ended on May 27, 1997, MMS received comments from five organizations.

Similarly, on April 4, 1997, MMS published the proposed rule for 30 CFR parts 202 and 216 (62 FR 16121). During the 30-day comment period that ended on May 5, 1997, MMS did not receive any formal comments. This final rule combines both of these proposed rules. We have combined RIN numbers 1010–AB97 and 1010–AC23 and we are now using the most recent RIN 1010–AC23 for this rule. The rule is necessary to:

- Reflect current industry technology,
- Form the basis for a gas verification system (GVS), and
- Require tracking of gas lost or used on the lease.

The Response to Comments section discusses the comments that MMS received from the proposed rule on oil and gas production measurement, surface commingling, and security. We appreciate the suggestions and comments that we received.

Response to Comments

Section 250.181 Definitions

MMS received comments to revise the following definitions to make them clearer or to align them with industry use and standards. In many cases, we agreed and made the appropriate changes to the definition.

- *Allocation meter*—We revised the definition to make it clearer, but we did not align it with the standard industry definition because the term carries a different meaning for purposes of this subpart.
- *British Thermal Unit (Btu)*—We revised the definition to align it with text book use, but we did not add a requirement to use Gas Processors Association (GPA) standards to calculate the ideal heating value at this time. We are further analyzing the GPA standards.
- *Calibration*—We revised the definition for clarity. We also added a phrase to show that, in this subpart, calibration includes testing (verifying) and correcting (if necessary) a measuring device.
- *Fractional analysis*—We changed ''fractional'' to ''compositional'' analysis for clarity. However, we rejected the recommendation in the comments to state that it is always on a gas analysis report, because the compositional analyses may not be on that report.
- *Gas lost*—One commenter suggested that we define this term. We agree, and have added it to the final rule. Gas lost is gas that is neither sold nor used on the lease or unit nor used internally by the producer.
- *Gas allocation meter*—We deleted the definition because it is covered under the definition of allocation meter.
- *Gas meter*—We received a comment suggesting that we delete the term gas meter because it is not necessary. We agree and deleted it accordingly.
- *Gas processing plant and gas processing plant statement*—We revised the definitions for clarity. We received a comment to the effect that the inlet stream is not always measured for volume and quality and that the statement may be a large document. We will work with industry to get the information that we need in the most convenient format. Also, we do not expect to need more than a few gas processing plant statements per year. We are accounting for the cost in the information collection report.
- *Gas royalty meter malfunction*—We revised the definition for clarity.
- *Gas volume statement*—We revised the definition for clarity. We agree with comments to the effect that the owner of the meter is not always the transporter of the gas. We therefore eliminated the descriptive statement that the owner of the gas meter prepares the document.
- *Inventory tank*—We added the definition for inventory tank because we use it in this subpart.
- *Liquid hydrocarbon*—We revised the definition for clarity. Contrary to the suggestion of one commenter, we did not define liquid hydrocarbons as hydrocarbons that always pass through lease facilities, because the processing plants are sometimes located onshore and not on an OCS lease.
- *Natural gas*—We revised the definition of natural gas for clarity.
- *Operating meter*—We revised the definition to clarify that the term includes only royalty and allocation meters.
- *Pressure base and temperature base*—We revised the definitions to require that these bases be used for reporting quality as well as volume.
- *Prove*—We revised the definition to agree with industry standards.
- *Retrograde condensate*—We revised the definition to agree with industry standards and added the term ''pipeline'' condensate here and throughout this subpart.
- *Royalty meter*—We revised the definition for clarity and accuracy.
- *Royalty tank*—We added this definition because it was cited under § 250.182(l) and not previously defined.
- *You or your*—We changed the word ''contractor'' in this definition to ''lessees' representative'' because much of the work in this subpart is performed by the lessees' representative.

Section 250.182 Liquid Hydrocarbon Measurement

- *(b)(1)(i)—We received a comment to add turbine meters in addition to the positive displacement meters referenced in the proposed rule. We also received a comment that coriolis meters might be used. We agree. We have therefore made more general requirements.*
- *(b)(1)(v)—We added that a sediment and water monitor must be located upstream of the divert valve to recognize this common industry practice.*
- *(b)(4)(i)*—We received a comment suggesting that we reference the industry standards for sampling. We agree and we revised the language accordingly.
- *(b)(4)(iii)*—We received a comment to be more specific about the sample probe location. We agree and made the suggested changes.
- *(c)*—We distinguished the requirements for run tickets that result from royalty meters from the requirements for run tickets pertaining to royalty tanks because they should be

treated slightly differently. We also reorganized this paragraph in order of importance.

• *(d)(4)*—We added a statement that allows for provings on a schedule that is different than monthly if the Regional Supervisor approves. This allows for unique situations that may occur.

• *(e)(1)*—We received a suggestion to require that the master meter be proved at several different rates to allow for the development of a meter factor curve. We realize that industry sometimes does this, and we will continue to evaluate this suggestion. We may address this, as well as technology advances, in a future rulemaking on gas measurement after the GVS is implemented.

• *(h)(1)*—We received a comment to change this phrase to the passive voice. MMS did not adopt this recommendation because we are trying to write in the active voice to clarify who must meet the requirement. We also received a comment to list the decimal value and the percentage for the differences in proof runs. We did not adopt this recommendation throughout because, in some cases, the output is an absolute number and in other cases the calculation leads to a percentage. We therefore, kept them separate.

• *(h)(2)*—We received a comment to change the language on the master meter proof runs to conform with industry standards. We have adopted the recommendation.

• *(i)(1)(i)*—We received a comment to add the term ''inspect'' before adjusting a meter to conform with industry standards. We agree, and we revised the language.

• *(i)(2)(iii)*—We changed the location of reporting unregistered production from the proving report to the run ticket because this is standard practice.

• *(k)(1)*—We agree with a comment to add the modifier ''proportional to flow'' to clarify the meaning of taking a sample continuously. Therefore, we revised the language.

• *(k)(6)*—We received a comment that adjusting and reproving the meter (if a meter factor differs from a previous meter factor by a specified percentage) is an accounting adjustment and not a physical one. The comment is not accurate. This provision refers to a physical adjustment of the meter.

• *(k)(7) and (k)(8)*—We received a comment to combine these statements. We have not combined them because another commenter recommended that we recognize that turbine meters cannot be adjusted. Combining the statements would not properly list the requirements for turbine meters. Also, paragraph (k)(8) discusses the required procedure when the meter factor differs by seven percent or more, in contrast to paragraph (k)(7)'s applicability to a meter factor difference of between two and seven percent. However, we have clarified the language to more precisely delineate the differences.

• *(k)(9)*—We added clarification that MMS may witness allocation meter provings. While this is not a change in policy, there seemed to be some question in the comments regarding whether MMS may witness allocation meter provings in addition to royalty meter provings.

• *(l)*—We separated tank facilities into ''royalty'' and ''inventory'' tank facilities because they should be treated differently.

Section 250.183 Gas Measurement

• *(b)*—We received a comment recommending that we include ''operators'' with ''lessees'' as parties who must meet this section's requirements. We agree. However, since the term '' you'' or ''your'' expressly includes operators and other lessee's representatives, this objective is accomplished by using the term ''you,'' which we have done throughout the final rule.

• *(b)(2)*—We received a comment to add the term ''verifiable'' instead of the word ''complete'' before ''measurement.'' We agree, and we modified the language.

• *(b)(3)*—We received a comment to add the phrase that measurement components ''should demonstrate consistent levels of accuracy throughout the system'' instead of ''compatible with their connected systems.'' We added the phrase with the exception of the ''should.'' MMS regulations are replacing forms of ''shall'' with ''must.''

• *(b)(4)*—We received comments saying that real time data should be displayed at the flow computer only. We agree, and we eliminated the phrase in the second sentence and referenced the industry standards.

• *(b)(5)*—We received comments saying that using on-line chromatographic analyzers is not necessary and not an industry practice because spot samples are sometimes taken. We agree, and we modified the language to reflect this. However, we did not restrict it to royalty sales meters because, like the current requirements on gas measurement, this also applies to allocation meters. However, less than 10 percent of the approved meters are allocation meters. Also, because MMS does not want to burden industry with additional sampling requirements, we changed the requirement from ''monthly'' to at least ''every 6 months'' to correspond with current industry practice.

• *(b)(6)*—MMS may need to see the gas quality information gathered from sampling; therefore, we added a reporting requirement on gas sampling information that is already available to the lessee. However, we anticipate that we will only occasionally request the information.

• *(b)(7)*—We added that the standard conditions for reporting gross heating value reflect the same degree of water saturation as in the gas volume to agree with Royalty Management regulations. We understand that this is standard industry practice.

• *(b)(8)*—We received a comment that we need to clarify that we will accept copies of the gas volume statements. We agree, and we made this change. We also received a comment that it is unclear as to how and when the statements will be requested, and if this is a limited sampling program. The Regional Supervisor will request, from the lessee or the lessees' representative, a sampling of the statements, at various times during the year, covering the previous month. We expect the emphasis to be on OCS gas royalty meters.

• *(b)(9)*—We received comments saying that the data that the Regional Supervisor may request in this requirement is too open ended. We agree, and we modified the language accordingly. We recognize that occasionally the data that we need concerning volume and quality dispositions may not be on the gas volume statement; therefore, this requirement is meant to encompass that data. We also modified the Information Collection Request to reflect that, at first, this data may take longer to retrieve than we originally estimated. However, we feel that this will become routine after the first few submittals.

• *(c)(1)*—We received a comment saying that we should not change the current rates for calibrations. However, a monthly calibration is needed to ensure that the meters stay accurate, so we have not made the recommended change.

• *(c)(2)*—We received a comment saying that we should add ''test (verify), repair, or/and calibrate the meter.'' We agree that these are the steps; however, our definition of calibration includes these steps so we changed the language to say ''calibrate each meter by using the manufacturer's specifications.''

• *(c)(3)*—We deleted the reference to specific meter types because other meters may be used. We also recognize that, as the commenter said, gas turbine meters are not customarily calibrated but are subject to operational testing. In addition, we added that the calibration should be as close as possible to the average hourly rate because we received a comment that the flow rate may be beyond the control of those responsible for calibration. We also received a comment that a meter factor curve should be allowed because it will increase accuracy. We are still evaluating this comment and we will analyze it for use in future rulemakings.

• *(c)(4)*—We received a comment that we should delete the term ''test data.'' We agree, and we changed the language to require that calibration reports, rather than test data, be retained.

• *(c)(5)*—We received a comment that MMS should witness only OCS royalty meter calibrations so we should change the rule to reflect this. We disagree. MMS may witness any calibrations for OCS royalty or allocation meters as defined in this subpart. In fact, the requirements in § 250.183 apply to both OCS gas royalty and allocation meters. This is not a change from the current requirements or the current policy. However, less than 10 percent of the approved meters are allocation meters. Inspections are needed if royalty is affected.

• *(d)*—We received a comment to add ''out of calibration or'' before ''malfunctioning'' because orifice meters are referred to as ''out of calibration.'' We agree, and we made the change. We also received a comment that a meter malfunction is when it is not operating within contractual tolerances. We agree, and we revised the language and the definition.

• *(d)(1)*—We received a comment that the requirement to calibrate gas meters should only refer to royalty meters. We disagree. Gas allocation meters must also be calibrated. This is not a change from current requirements.

• *(d)(2)(i)*—One commenter recommended removing the statement that MMS ''does not require retroactive volume adjustments for allocation beyond 21 days'' that was made in the proposed rule after the requirement to calculate the volume adjustment for the determinable period of a calibration error. The commenter felt that the quoted statement would hinder industry in obtaining monetary adjustments from purchasers for periods longer than 21 days for which adjustments for allocation would be nevertheless required because the error period could not be determined. We agree, and we revised the final rule accordingly.

• *(e)(1)(i)*—We received a comment to add that we are requiring only a copy of the gas processing plant statement. We agree, and we revised the final rule. We also received a comment to be more specific about what we are asking for on the statement. We agree, and the new paragraph (e)(1)(ii), specifies that we need the gross heating values of the inlet and residue streams if they are not reported on the gas plant statement. However, we believe that most gas plant statements will have the necessary information.

• *(e)(1)(ii)*—We received a comment saying that we should delete the requirement to submit gas volume statements for each meter facility because the information will already be on the gas volume statement that we may request. We agree, and we deleted the requirement.

• *(e)(1)(iii)*—We received a comment saying that gathering the compositional fractional analyses for the gas plant statements will be very time consuming for industry. We agree, and we deleted the term ''composite fractional analyses.''

• *(e)(2)*—One commenter inquired why MMS would inspect gas plants. MMS recognizes that most of the royalty measuring points for gas meters in the Gulf of Mexico OCS are located on OCS offshore facilities. However, that is not the case in the Pacific OCS where almost all of the oil and gas royalty measuring points are located at an onshore oil and gas plant facility and operated by the lessee.

Though most onshore oil and gas plants are on State owned property, the oil and gas that comes into the plant is still oil and gas produced from the Federal OCS and subject to all of the laws and regulations pertaining to Federal royalty and inspection requirements. This includes access to the onshore facility's Liquid Automatic Custody Transfer (LACT) Unit and gas sales meters for the purpose of witnessing a LACT meter proving, a gas meter calibration, or site security for both royalty measuring points. These inspections will continue to be conducted by MMS inspectors. However, we only expect to need information from a relatively few gas plants each year.

Section 250.184 Surface Commingling

• *(a)(2)(iii)*—We received a comment saying that this requirement was too open ended as stated. We agree. In the end, we deleted most of the specific requirements concerning the contents of a commingling application because we did not want to create a misunderstanding that no other kinds of information would ever be necessary. Because each commingling application is unique, it is best to contact the Regional Supervisor prior to submitting a commingling application.

• *(a)(3)*—We received a comment saying that MMS should publish the paper presented at the May 29, 1996, Acadian Flow Measurement Society Conference. Because it is only an example of a commingling application, we have not published it as part of the regulations. However, the paper is available to the public. Please contact the Regional Supervisor in the Gulf of Mexico OCS Region if you would like a copy.

• *(a)(4)*—We received a comment that MMS should delete this requirement [currently (a)(2)] because it is inappropriate. We agree that as written it may be confusing; therefore, we significantly re-wrote the requirement for clarity.

Section 250.185 Site Security

• *(a)(2)*—We received a request to clarify if this requirement pertains to onshore or offshore tanks and to stock or surge tanks. This applies to both inventory and royalty tanks (onshore and offshore) which are used in the royalty determination process. Therefore, by definition, this includes surge tanks. We clarified the requirement.

• *(b)(1)*—We received a comment to add the term ''meter'' after ''royalty.'' We agree, and we revised the final rule for clarification.

• *(b)(1)(i)*—We received a comment saying that it is impractical to seal the conduit leading to the control room. We agree, and we modified the language to clarify the location for the seals.

• *(b)(1)(ii)*—We received a comment requesting clarification on the seals for sampling systems. We agree, and we removed the term *chains.*

• *(b)(2)*—We received comments concerning our statement in the preamble that we may require seals on gas meters. A comment stated that it is impractical to seal an orifice meter. Another comment said that to seal all valves and gas metering devices in the Gulf of Mexico is needless. We did not intend to have orifice meter, or all valves and gas meter devices, sealed. Therefore, we changed the language to say *seal all bypass valves of gas royalty and allocation meters.* We are including the increased cost of the seals in our economic analysis.

Section 250.186 Measuring Gas Lost or Used on a Lease

In the final rule, MMS moved this section to new paragraphs in § 250.183 (f) (1) through (5) because it relates to gas measurement.

• *(a)*—We received comments that MMS should not require a lessee to measure the gas lost or used on a lease in every case because we currently allow them to either estimate or measure those volumes. We agree, and we modified the language.

• *(b)*—We received a comment that the cost of measuring gas lost or used on a lease would be substantial if the meters are not currently in place. We agree, and we modified the language to give the lessee the option of measuring or estimating the gas lost or used. We also received a question concerning what we mean by gas lost. Gas lost is gas that is neither sold nor used on the lease or unit nor used internally by the producer. We have added a definition of this term in § 250.181.

• *(d)*—We received a comment that documents are not always retained at the site but they can be easily obtained for an inspector to see. We agree, and we modified the language in the final rule. We also added that the documents must be kept for *at least* 2 years for consistency with audit requirements. If an audit occurs, MMS requires 6 years of documents under separate regulations governing audits. However, the inspectors will only need to see documents for the previous 2 years.

General Comments

• We received comments concerning the time it will take to submit copies of gas volume statements. We intend for this to be a sampling approach—on an ''as needed'' basis, upon the request of the Regional Supervisor. We realize that at first it will take longer to submit the copies of the statements. Also, occasionally we anticipate that the statement may not have the usual and customary volume and quality information or the saturation conditions. However, in time, the needed information should become relatively routine to obtain. We will work with industry to minimize the burden and to make the reporting and the methods of reporting as accommodating as possible. We also modified the information collection to reflect the possibility of some information being more difficult to obtain at first.

• We received comments on the subject of ''Documents Incorporated.'' The comment said that we need to incorporate three additional Chapters from the American Petroleum Institute (API) Manual of Petroleum Measurement Standard (MPMS). After reviewing the Chapters, we have incorporated: Chapter 1, Vocabulary; Chapter 20.1, Allocation Measurement; and Chapter 21.1, Electronic Gas Measurement as referenced in 30 CFR 250, Subpart A. MMS regulations that are different than the cited standards supercede the standard. For example, MMS has a few slightly different definitions and a different calibration rate than the cited standard, but MMS requirements will supercede the standard. Further, by adopting the API MPMS Chapter 20.1, Allocation Measurement, MMS is not automatically adopting the API MPMS Chapter 14.1, Collecting and Handling of Natural Gas Samples for Custody Transfer, which is cited in the standard document. We are reviewing that standard. Also, the new tabular format for the documents that we incorporate was created to assist users to easily find the citations for the documents that we incorporate by reference. We hope that you find this useful.

• In the proposed rule, MMS also sought comments on the applicable industry standards listed in 30 CFR 250.1 and incorporated by reference in the proposed rule (62 FR 8666). MMS received no negative comments on the use of those standards.

Executive Order (E.O.) 12866

This rule is not significant under E.O. 12866 and has not been reviewed by the Office of Management and Budget. The estimated total annual cost of compliance is less than $100 million, and the estimated level of newly imposed costs should not affect business and operating decisions in the OCS.

E.O. 12988

The Department of the Interior (DOI) has certified to the Office of Management and Budget (OMB) that this rule meets the applicable reform standards provided in sections 3(a) and 3(b)(2) of E.O. 12988.

Unfunded Mandates Reform Act of 1995

DOI has determined and certifies according to the Unfunded Mandates Reform Act, 2 U.S.C. 1502 *et seq.*, that this rule will not impose a cost of $100 million or more in any year on State, local, and tribal governments, or the private sector.

Regulatory Flexibility Act

DOI has determined that because this rule applies to all OCS lessees, the lessees that are small businesses will be affected. However, the new economic burden, that includes collecting information and keeping records, is not a significant burden when compared to the amount of funding that is required to operate in the OCS. The annual burden to all OCS lessees is expected to be $186,550 for reporting and recordkeeping. In addition, the annual burden for complying with new seal and sampling requirements that are not standard practice is estimated to be $21,000. The impact is calculated using $35 per burden hour. In comparison, the average annual operating cost for each facility on the OCS is approximately $1 million per facility and $300,000 per well. This is in addition to the capital cost for the facility which may be greater than $200 million. Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small business about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of MMS, call toll-free (888) 734–3247.

Paperwork Reduction Act (PRA)

This rule contains information collections with different OMB approval numbers. The information collections are affected by this rule as shown in the following table.

The information collections in	Have the OMB approval number	and
Parts 202 and 216	1010–0040	Are not modified by this rule.
Subpart L of part 250	1010–0051	Are modified by this rule.

As part of the notice of proposed rulemaking (NPR) process, we submitted the revised information collection requirements in 30 CFR part 250, Subpart L, to OMB for approval.

OMB approved the information collection under OMB Control No. 1010-0051. A discussion of the comments received on the information collection aspects of the NPR for this subpart is included in the preamble. Based on changes made in this rule, we've submitted a revised information collection package to OMB for approval. The PRA 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 information collection aspects of this final rule will not take effect until approved by OMB. We will publish a notice in the **Federal Register** announcing the OMB approval of the revised collection of information associated with 30 CFR 250, Subpart L.

We invite the public and other Federal agencies to comment on this collection of information. Send comments regarding any aspect of the collection to the Office of Information and Regulatory Affairs, OMB, Attention: Desk Officer for the Interior Department (1010–0051), 725 17th Street N.W., Washington, D.C. 20503. Send a copy of your comments to the Information Collection Clearance Officer, Minerals Management Service, 1849 C Street N.W., MS 4230, Washington, D.C. 20240. OMB is required to make a decision concerning the collection of information contained in this final rule between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, your comments are best assured of being considered by OMB if OMB receives them by June 11, 1998.

This final rule for 30 CFR part 250, Subpart L, makes very few changes to the information collection requirements approved for the proposed rulemaking. Minor changes include relocating or separating various requirements for clarity and specificity. We reestimated the burdens for providing gas volume statements to reflect that, at first, these data may take longer to retrieve than we originally estimated. We also made slight adjustments to other estimates. There are two new requirements at §§ 250.182(a)(4) and (d)(4). The first requires lessees to submit pipeline (retrograde) condensate volumes upon request; and the second accommodates unique situations that may occur and allows for provings on a schedule that is different than monthly if the Regional Supervisor approves.

MMS collects the information required in Subpart L in order to ensure that the volumes of hydrocarbons produced are measured accurately, and royalties are paid on the proper volumes. Specifically, MMS uses the information to:

- Determine if measurement equipment is properly installed, provides accurate measurement of production on which royalty is due, and is operating properly;
- Obtain rates of production data in allocating the volumes of production measured at royalty sales meters which can be examined during field inspections;
- Ascertain if all removals of oil and condensate from the lease are reported;
- Determine the amount of oil that was shipped when measurements are taken by gauging the tanks rather than being measured by a meter;
- Ensure that the sales location is secure and production cannot be removed without the volumes being recorded; and
- Review proving reports to verify that data on run tickets are calculated and reported accurately.

Responses are mandatory. We will protect information considered proprietary under applicable law and under regulations at § 250.18 of this part and 30 CFR part 252 of this chapter.

Respondents are approximately 130 Federal OCS oil and gas lessees. The reporting and recordkeeping hour burden varies by section of the rule. We estimate the total burden will average approximately 41 hours per respondent. This includes the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. You may contact the MMS Information Collection Clearance Officer at 202/208–7744 to obtain a copy of the burden breakdown and the complete supporting statement submitted to OMB. In calculating the burdens, we've assumed that respondents perform some of the requirements and maintain records in the normal course of their activities. We consider these to be usual and customary. We invite your comments if you disagree with this assumption.

(1) We specifically solicit comments on the following questions:

(a) Is the proposed collection of information necessary for us to properly perform our functions, and will it be useful?

(b) Are the burden hour estimates reasonable for the proposed collection?

(c) Do you have any suggestions that would enhance the quality, clarity, or usefulness of the information to be collected?

(d) Is there a way to minimize the information collection burden on the applicants, including the use of appropriate automated electronic, mechanical, or other forms of information technology?

(2) In addition, the PRA requires us to estimate the total annual cost burden to respondents or recordkeepers resulting from the collection of information. We need your comments on this item. Your response should split the cost estimate into two components:

(a) Total capital and startup cost component; and

(b) Annual operation, maintenance, and purchase of services component.

Your estimates should consider the costs to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Capital and startup costs include, among other items, computers and software you purchase to prepare for collecting information; monitoring, sampling, drilling, and testing equipment; and record storage facilities. Generally, your estimates should not include equipment or services purchased: (i) before October 1, 1995; (ii) to comply with requirements not associated with the information collection; (iii) for reasons other than to provide information or keep records for the Government; or (iv) as part of customary and usual business or private practices.

Takings Implication Assessment

DOI certifies that this rule does not represent a governmental action capable of interference with constitutionally protected property rights. Thus, a Takings Implication Assessment need not be prepared pursuant to E.O. 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

National Environmental Policy Act

DOI determined that this rule does not constitute a major Federal action significantly affecting the quality of the human environment; therefore, an Environmental Impact Statement is not required.

List of Subjects

30 CFR Part 202

Coal, Continental shelf, Geothermal energy, Government contracts, Indian lands, Mineral royalties, Natural gas, Petroleum, Public lands-mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 216

Coal, Continental shelf, Geothermal energy, Government contracts, Indian lands, Mineral royalties, Natural gas, Penalties, Petroleum, Public lands-mineral resources, Reporting and recordkeeping requirements.

30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Mineral royalties, Oil and gas development and production, Oil and gas exploration, Oil and gas reserves, Penalties, Pipelines, Natural gas, Petroleum, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur development and production, Sulphur exploration, Surety bonds.

Dated: April 24, 1998.

Bob Armstrong,

Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Minerals Management Service (MMS) is amending 30 CFR parts 202, 216, and 250 as follows:

PART 202—ROYALTIES

1. The authority citation for part 202 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*, 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*, 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*, 31 U.S.C. 9701 *et seq.*, 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, 1801 *et seq.*

Subpart D—Federal and Indian Gas

2. Revise § 202.152(a)(1) to read as follows:

§ 202.152 Standards for reporting and paying royalties on gas.

(a)(1) If you are responsible for reporting production or royalties, you must:

(i) Report gas volumes and British thermal unit (Btu) heating values, if applicable, under the same degree of water saturation;

(ii) Report gas volumes in units of 1,000 cubic feet (mcf); and

(iii) Report gas volumes and Btu heating value at a standard pressure base of 14.73 pounds per square inch absolute (psia) and a standard temperature base of 60° F.

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PART 216—PRODUCTION ACCOUNTING

1. The authority citation for part 216 continues to read as follows:

Authority: 5 U.S.C. 301 *et seq.*, 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*, 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*, 31 U.S.C. 3716, 3720A, 9701, 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, 1801 *et seq.*

Subpart B—Oil and Gas, General

2. Revise § 216.54 to read as follows:

§ 216.54 Gas Analysis Report.

When requested by MMS, any operator must file a Gas Analysis Report (GAR) (Form MMS–4055) for each royalty or allocation meter. The form must contain accurate and detailed gas analysis information. This requirement applies to offshore, onshore, or Indian leases.

(a) MMS may request a GAR when you sell gas, or transfer gas for processing, before the point of royalty computation.

(b) When MMS first requests this report, the report is due within 30 days. If MMS requests subsequent reports, they will be due no later than 45 days after the end of the month covered by the report.

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

1. The authority citation for part 250 continues to read as follows:

Authority: 43 U.S.C. 1331, et seq.

2. Revise § 250.1 to read as follows:

§ 250.1 Documents incorporated by reference.

(a) MMS is incorporating by reference the documents listed in the table in paragraph (d) of this section. The Director of the Federal Register has approved this incorporation by reference in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

(1) MMS will publish any changes to these documents in the **Federal Register**.

(2) The rule change will become effective without prior opportunity to comment when MMS determines that the revisions to a document result in safety improvements or represent new industry standard technology, and do not impose undue costs on the affected parties.

(b) MMS has incorporated each document or specific portion by reference in the sections noted. The entire document is incorporated by reference, unless the text of the corresponding sections in this part calls for compliance with specific portions of the listed documents. In each instance, the applicable document is the specific edition or specific edition and supplement or addendum cited in this section.

(c) In accordance with §§ 250.3 (c), and 250.14(b), you may comply with a later edition of a specific document incorporated by reference provided:

(1) You demonstrate that compliance with the later edition provides a degree of protection, safety, or performance equal to or better than that which would be achieved by compliance with the listed edition; and

(2) You obtain the prior written approval for alternative compliance from the authorized MMS official.

(d) You may inspect these documents at the Minerals Management Service, 381 Elden Street, Room 3313, Herndon, Virginia; or at the Office of the Federal Register, 800 North Capitol Street, N.W., Suite 700, Washington, D.C.. You may obtain the documents from the publishing organizations at the addresses given in the following table.

For	Write to
ACI Standards	American Concrete Institute, P. O. Box 19150, Detroit, MI 48219.
AISC Standards	AISC—American Institute of Steel Construction, Inc., P.O. Box 4588, Chicago, IL 60680.
ANSI/ASME Codes	American National Standards Institute, Attention Sales Department, 1430 Broadway, New York, NY 10018; and/or American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, NY 10017.
API Recommended Practices, Specs, Standards, Manual of Petroleum Measurement Standards (MPMS) chapters.	American Petroleum Institute, 1220 L Street N.W., Washington, D.C. 20005.
ASTM Standards	American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103.
AWS Codes	American Welding Society, 550 N.W., LeJeune Road, P.O. Box 351040, Miami, FL 33135.
NACE Standards	National Association of Corrosion Engineers, P.O. Box 218340, Houston, TX 77218.

(e) In order to easily reference text of the corresponding sections with the list of documents incorporated by reference, the list is in alphanumerical order by organization and document.

Title of document	Incorporated by reference at
ACI Standard 318–95, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R–95).	§ 250.138(b)(4)(i), (b)(6)(i), (b)(7), (b)(8)(i), (b)(9), (b)(10), (c)(3), (d)(1)(v), (d)(5), (d)(6), (d)(7), (d)(8), (d)(9), (e)(1)(i), (e)(2)(i).
ACI Standard 357–R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984.	§ 250.130(g);§ 250.138 (c)(2), (c)(3).
AISC Standard, Specification for Structural Steel for Buildings, Allowable Stress Design and Plastic Design, June 1, 1989, with Commentary.	§ 250.137(b)(1)(ii), (c)(4)(ii), (c)(4)(vii).
ANSI/ASME Boiler and Pressure Vessel Code, Section I, Power Boilers including Appendices, 1995 Edition.	§ 250.123(b)(1), (b)(1)(i); § 250.292(b)(1), (b)(1)(i).
ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Heating Boilers including Nonmandatory Appendices A, B, C, D, E, F, H, I, and J, and the Guide to Manufacturers Data Report Forms, 1995 Edition.	§ 250.123(b)(1), (b)(1)(i); § 250.292(b)(1), (b)(1)(i).
ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Divisions 1 and 2, including Nonmandatory Appendices, 1995 Edition.	§ 250.123(b)(1), (b)(1)(i); § 250.292(b)(1), (b)(1)(i).
ANSI/ASME B 16.5–1988 (including Errata) and B 16.5a–1992 Addenda, Pipe Flanges and Flanged Fittings.	§ 250.152(b)(2).
ANSI/ASME B 31.8–1995, Gas Transmission and Distribution Piping Systems	§ 250.152(a).
ANSI Z88.2—1992, American National Standard for Respiratory Protection	§ 250.67(g)(4)(iv), (j)(13)(ii).
ANSI/ASME SPPE–1–1994 and SPPE–1d–1996, ADDENDA, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations.	§ 250.126(a)(2)(ii).
API RP 2A, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms Working Stress Design, Nineteenth Edition, August 1, 1991, API Stock No. 811–00200.	§ 250.130(g); § 250.142(a).
API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Third Edition, June 1, 1995, API Stock No. G02D03.	§ 250.20(c); § 250.260(g).
API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fourth Edition, July 1, 1994, with Errata dated June 1996, API Stock No. G14B04.	§ 250.121(e)(4); § 250.124(a)(1)(i); § 250.126(d).
API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Fourth Edition, September 1, 1986, API Stock No. 811–07180.	§ 250.122(b), (e)(2); § 250.123(a), (b)(2)(i), (b)(4), (b)(5)(i), (b)(7), (b)(9)(v), (c)(2); § 250.124(a), (a)(5); § 250.152(d); § 250.154(b)(9); § 250.291(c), (d)(2); § 250.292(b)(2), (b)(4)(v); § 250.293(a).
API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1, 1991, API Stock No. G07185.	§ 250.122(e)(3); § 250.291(b)(2), (d)(3).
API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms, Third Edition, September 1, 1991, API Stock No. G07190.	§ 250.53(c); § 250.123(b)(9)(v); § 250.292(b)(4)(v).
API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, Third Edition, December 1, 1993, API Stock No. G07194.	§ 250.123(b)(8), (b)(9)(v); § 250.292(b)(3), (b)(4)(v).
API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fourth Edition, July 1, 1994, API Stock No. G14H04.	§ 250.122(d); § 250.126(d).
API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, First Edition, June 1, 1991, API Stock No. G06005.	§ 250.53(b); § 250.122(e)(4)(i); § 250.123(b)(9)(i); § 250.291(b)(3); (d)(4)(i); § 250.292(b)(4)(i).
API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993, API Stock No. H25560.	§ 250.182(l)(4).
API Spec Q1, Specification for Quality Programs, Third Edition, June 1990, API Stock No. 811–00001a.	§ 250.126(a)(2)(ii).
API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, Seventeenth Edition, February 1, 1996, API Stock No. G06A17.	§ 250.126 (a)(3); § 250.152(b)(1), (b)(2).
API Spec 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996, API Stock No. G06AV1.	§ 250.126(a)(3).
API Spec 6D, Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves), Twenty-first Edition, March 31, 1994, API Stock No. G03200.	§ 250.152(b)(1).
API Spec 14A, Specification for Subsurface Safety Valve Equipment, Ninth Edition, July 1, 1994, API Stock No. G14A09.	§ 250.126(a)(3).
API Spec 14D, Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, Ninth Edition, June 1, 1994, with Errata dated August 1, 1994, API Stock No. G07183.	§ 250.126(a)(3).
API Standard 2545, Method of Gaging Petroleum and Petroleum Products, October 1965, reaffirmed October 1992; also available as ANSI/American Society of Testing Materials (ASTM) D 1085–65, API Stock No. H25450.	§ 250.182(l)(4).
API Standard 2551, Standard Method for Measurement and Calibration of Horizontal Tanks, First Edition, 1965, reaffirmed October 1992; also available as ANSI/ASTM D 1410–65, reapproved 1984, API Stock No. H25510.	§ 250.182(l)(4).
API Standard 2552, Measurement and Calibration of Spheres and Spheroids, First Edition, 1966, reaffirmed October 1992; also available as ANSI/ASTM D 1408–65, reapproved 1984, API Stock No. H25520.	§ 250.182(l)(4).

Title of document	Incorporated by reference at
API Standard 2555, Method for Liquid Calibration of Tanks, September 1966, reaffirmed October 1992; also available as ANSI/ASTM D 1406–65, reapproved 1984, API Stock No. H25550.	§ 250.182(l)(4).
MPMS, Chapter 1, Vocabulary, Second Edition, July 1994, API Stock No. H01002	§ 250.181.
MPMS, Chapter 2, Tank Calibration, Section 2A, Measurement and Calibration of Upright Cylindrical Tanks by the Manual Strapping Method, First Edition, February 1995, API Stock No. H022A1.	§ 250.182(l)(4).
MPMS, Chapter 2, Section 2B, Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989; also available as ANSI/ASTM D4738–88, API Stock No. H30023.	§ 250.182(l)(4).
MPMS, Chapter 3, Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, First Edition, December 1994, API Stock No. H031A1.	§ 250.182(l)(4).
MPMS, Chapter 3, Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, First Edition, April 1992, API Stock No. H30060.	§ 250.182(l)(4).
MPMS, Chapter 4, Proving Systems, Section 1, Introduction, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30081.	§ 250.182(a)(3),(f)(1).
MPMS, Chapter 4, Section 2, Conventional Pipe Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30082.	§ 250.182(a)(3),(f)(1).
MPMS, Chapter 4, Section 3, Small Volume Provers, First edition, July 1988, reaffirmed October 1993, API Stock No. H30083.	§ 250.182(a)(3),(f)(1).
MPMS, Chapter 4, Section 4, Tank Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30084.	§ 250.182(a)(3),(f)(1).
MPMS, Chapter 4, Section 5, Master-Meter Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30085.	§ 250.182(a)(3), (f)(1).
MPMS, Chapter 4, Section 6, Pulse Interpolation, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30086.	§ 250.182(a)(3), (f)(1).
MPMS, Chapter 4, Section 7, Field-Standard Test Measures, First Edition, October 1988, API Stock No. H30087.	§ 250.182(a)(3), (f)(1).
MPMS, Chapter 5, Metering, Section 1, General Considerations for Measurement by Meters, Third Edition, September 1995, API Stock No. H05013.	§ 250.182(a)(3).
MPMS, Chapter 5, Section 2, Measurement of Liquid Hydrocarbons by Displacement Meters, Second Edition, November 1987, reaffirmed October 1992, API Stock No. H30102.	§ 250.182(a)(3).
MPMS, Chapter 5, Section 3, Measurement of Liquid Hydrocarbons by Turbine Meters, Third Edition, September 1995, API Stock No. H05033.	§ 250.182(a)(3).
MPMS, Chapter 5, Section 4, Accessory Equipment for Liquid Meters, Third Edition, September 1995, with Errata, March 1996, API Stock No. H05043.	§ 250.182(a)(3).
MPMS, Chapter 5, Section 5, Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, First Edition, June 1982, reaffirmed October 1992, API Stock No. H30105.	§ 250.182(a)(3).
MPMS, Chapter 6, Metering Assemblies, Section 1, Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991, API Stock No. H30121.	§ 250.182(a)(3).
MPMS, Chapter 6, Section 6, Pipeline Metering Systems, Second Edition, May 1991, API Stock No. H30126.	§ 250.182(a)(3).
MPMS, Chapter 6, Section 7, Metering Viscous Hydrocarbons, Second Edition, May 1991, API Stock No. H30127.	§ 250.182(a)(3).
MPMS, Chapter 7, Temperature Determination, Section 2, Dynamic Temperature Determination, Second Edition, March 1995, API Stock No. H07022.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 7, Section 3, Static Temperature Determination Using Portable Electronic Thermometers, First Edition, July 1985, reaffirmed March 1990, API Stock No. H30143.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 8, Sampling, Section 1, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; also available as ANSI/ASTM D 4057–88, API Stock No. H30161.	§ 250.182 (b)(4)(i), (l)(4).
MPMS, Chapter 8, Section 2, Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products, Second Edition, October 1995; also available as ANSI/ASTM D 4177, API Stock No. H30162.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 9, Density Determination, Section 1, Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products, First Edition, June 1981, reaffirmed October 1992; also available as ANSI/ASTM D 1298, API Stock No. H30181.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 9, Section 2, Pressure Hydrometer Test Method for Density or Relative Density, First Edition, April 1982, reaffirmed October 1992, API Stock No. H30182.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 10, Sediment and Water, Section 1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method, First Edition, April 1981, reaffirmed December 1993; also available as ANSI/ASTM D 473, API Stock No. H30201.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 10, Section 2, Determination of Water in Crude Oil by Distillation Method, First Edition, April 1981, reaffirmed December 1993; also available as ANSI/ASTM D 4006, API Stock No. H30202.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 10, Section 3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), First Edition, April 1981, reaffirmed December 1993; also available as ANSI/ASTM D 4007, API Stock No. H30203.	§ 250.182 (a)(3), (l)(4).
MPMS, Chapter 10, Section 4, Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure), Second Edition, May 1988; also available as ANSI/ASTM D 96, API Stock No. H30204.	§ 250.182 (a)(3), (l)(4).

Title of document	Incorporated by reference at
MPMS, Chapter 11.1, Volume Correction Factors, Volume 1, Table 5A—Generalized Crude Oils and JP–4 Correction of Observed API Gravity to API Gravity at 60°F, and Table 6A—Generalized Crude Oils and JP–4 Correction of Observed API Gravity to API Gravity at 60°F, First Edition, August 1980, reaffirmed October 1993; also available as ANSI/ASTM D 1250, API Stock No. H27000.	§ 250.182 (a)(3), (g)(3), (l)(4).
MPMS, Chapter 11.2.1, Compressibility Factors for Hydrocarbons: 0–90° API Gravity Range, First Edition, August 1984, reaffirmed May 1996, API Stock No. H27300.	§ 250.182(a)(3),(g)(4).
MPMS, Chapter 11.2.2, Compressibility Factors for Hydrocarbons: 0.350–0.637 Relative Density (60°F/60°F) and −50°F to 140°F Metering Temperature, Second Edition, October 1986, reaffirmed October 1992; also available as Gas Processors Association (GPA) 8286–86, API Stock No. H27307.	§ 250.182(a)(3),(g)(4).
MPMS, Chapter 11, Physical Properties Data, Addendum to Section 2.2, Compressibility Factors for Hydrocarbons, Correlation of Vapor Pressure for Commercial Natural Gas Liquids, First Edition, December 1994; also available as GPA TP–15, API Stock No. H27308.	§ 250.182(a)(3).
MPMS, Chapter 11.2.3, Water Calibration of Volumetric Provers, First Edition, August 1984, reaffirmed, May 1996, API Stock No. H27310.	§ 250.182(f)(1).
MPMS, Chapter 12, Calculation of Petroleum Quantities, Section 2, Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Including Parts 1 and 2, Second Edition, May 1995; also available as ANSI/API MPMS 12.2–1981, API Stock No. H30302.	§ 250.182(a)(3), (g)(1), (g)(2)
MPMS, Chapter 14, Natural Gas Fluids Measurement, Section 3, Concentric Square-Edged Orifice Meters, Part 1, General Equations and Uncertainty Guidelines, Third Edition, September 1990; also available as ANSI/API 2530, Part 1, 1991, API Stock No. H30350.	§ 250.183(b)(2).
MPMS, Chapter 14, Section 3, Part 2, Specification and Installation Requirements, Third Edition, February 1991; also available as ANSI/API 2530, Part 2, 1991, API Stock No. H30351.	§ 250.183(b)(2).
MPMS, Chapter 14, Section 3, Part 3, Natural Gas Applications, Third Edition, August 1992; also available as ANSI/API 2530, Part 3, API Stock No. H30353.	§ 250.183(b)(2).
MPMS, Chapter 14, Section 5, Calculation of Gross Heating Value, Relative Density, and Compressibility Factor for Natural Gas Mixtures From Compositional Analysis, Revised, 1996; also available as ANSI/API MPMS 14.5–1981, order from Gas Processors Association, 6526 East 60th Street, Tulsa, Oklahoma 74145.	§ 250.183(b)(2).
MPMS, Chapter 14, Section 6, Continuous Density Measurement, Second Edition, April 1991, API Stock No. H30346.	§ 250.183(b)(2).
MPMS, Chapter 14, Section 8, Liquefied Petroleum Gas Measurement, First Edition, February 1983, reaffirmed May 1996, API Stock No. H30348.	§ 250.183(b)(2).
MPMS, Chapter 20, Section 1, Allocation Measurement, First Edition, September 1993, API Stock No. H30701.	§ 250.182(k)(1).
MPMS, Chapter 21, Section 1, Electronic Gas Measurement, First Edition, September 1993, API Stock No. H30730.	§ 250.183(b)(4).
ASTM Standard C33–93, Standard Specification for Concrete Aggregates including Nonmandatory Appendix.	§ 250.138(b)(4)(i).
ASTM Standard C94–96, Standard Specification for Ready-Mixed Concrete	§ 250.138(e)(2)(i).
ASTM Standard C150–95a, Standard Specification for Portland Cement	§ 250.138(b)(2)(i).
ASTM Standard C330–89, Standard Specification for Lightweight Aggregates for Structural Concrete.	§ 250.138(b)(4)(i).
ASTM Standard C595–94, Standard Specification for Blended Hydraulic Cements	§ 250.138(b)(2)(i).
D1.1–96, Structural Welding Code—Steel, 1996, including Commentary	§ 250.137(b)(1)(i).
DI.4–79, Structural Welding Code—Reinforcing Steel, 1979	§ 250.138 (e)(3)(ii).
NACE Standard MR–01–75–96, Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment, January 1996.	§ 250.67 (p)(2).
NACE Standard RP 0176–94, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production.	§ 250.137(d).

3. Revise Subpart L to read as follows:

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

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

§ 250.180 Question Index Table.

The table in this section lists questions concerning Oil and Gas Production Measurement, Surface Commingling, and Security.

Frequently asked questions	CFR citation
1. What are the requirements for measuring liquid hydrocarbons?	§ 250.182(a).
2. What are the requirements for liquid hydrocarbon royalty meters?	§ 250.182(b).
3. What are the requirements for run tickets?	§ 250.182(c).
4. What are the requirements for liquid hydrocarbon royalty meter provings?	§ 250.182(d).
5. What are the requirements for calibrating a master meter used in royalty meter provings?	§ 250.182(e).
6. What are the requirements for calibrating mechanical-displacement provers and tank provers?	§ 250.182(f).

Frequently asked questions	CFR citation
7. What correction factors must I use when proving meters with a mechanical displacement prover, tank prover, or master meter?.	§ 250.182(g).
8. What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?	§ 250.182(h).
9. Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must I do?	§ 250.182(i).
10. How must I correct gross liquid hydrocarbon volumes to standard conditions?	§ 250.182(j).
11. What are the requirements for liquid hydrocarbon allocation meters?	§ 250.182(k).
12. What are the requirements for royalty and inventory tank facilities ?	§ 250.182(l).
13. To which meters do MMS requirements for gas measurement apply?	§ 250.183(a).
14. What are the requirements for measuring gas?	§ 250.183(b).
15. What are the requirements for gas meter calibrations?	§ 250.183(c).
16. What must I do if a gas meter is out of calibration or malfunctioning?	§ 250.183(d).
17. What are the requirements when natural gas from a Federal lease on the OCS is transferred to a gas plant before royalty determination?.	§ 250.183(e).
18. What are the requirements for measuring gas lost or used on a lease?	§ 250.183(f).
19. What are the requirements for the surface commingling of production?	§ 250.184(a).
20. What are the requirements for a periodic well test used for allocation?	§ 250.184(b).
21. What are the requirements for site security?	§ 250.185(a).
22. What are the requirements for using seals?	§ 250.185(b).

§ 250.181 Definitions.

Terms not defined in this section have the meanings given in the applicable chapter of the API MPMS, which is incorporated by reference in 30 CFR 250.1. Terms used in Subpart L have the following meaning:

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

API MPMS—the American Petroleum Institute's Manual of Petroleum Measurement Standards, chapters 1, 20, and 21.

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

Calibration—testing (verifying) and correcting, if necessary, a measuring device to industry accepted, manufacturer's recommended, or regulatory required standard of accuracy.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Surface commingling—the surface mixing of production from two or more leases or units prior to measurement for royalty purposes.

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

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

§ 250.182 Liquid hydrocarbon measurement.

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

(1) Submit a written application to, and obtain approval from, the Regional

Supervisor before commencing liquid hydrocarbon production or making changes to previously approved measurement procedures;

(2) Use measurement equipment that will accurately measure the liquid hydrocarbons produced from a lease or unit;

(3) Use procedures and correction factors according to the applicable chapters of the API MPMS as incorporated by reference in 30 CFR 250.1, when obtaining net standard volume and associated measurement parameters; and

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

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

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

(i) A meter equipped with a nonreset totalizer;

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

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

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

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

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

(i) Prevent flow reversal through the meter;

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

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

(iv) Prevent meter bypassing.

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

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

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

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

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

(i) The sampling point is in the flowstream immediately upstream or downstream of the meter or divert valve (in accordance with the API MPMS as incorporated by reference in 30 CFR 250.1);

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

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

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

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

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

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

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

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

(1) Permit MMS representatives to witness provings;

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

(3) Prove each operating royalty meter to determine the meter factor monthly, but the time between meter factor determinations must not exceed 42 days;

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

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

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

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

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

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

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

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

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

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

(1) Calibrate mechanical-displacement provers and tank provers at least once every 5 years according to the API MPMS as incorporated by reference in 30 CFR 250.1; and

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

(g) *What correction factors must a I use when proving meters with a mechanical-displacement prover, tank prover, or master meter?* Calculate the following correction factors using the API MPMS as referenced in 30 CFR 250, Subpart A:

(1) The change in prover volume due to the effect of temperature on steel (Cts);

(2) The change in prover volume due to the effect of pressure on steel (Cps);

(3) The change in liquid volume due to the effect of temperature on a liquid (Ctl); and

(4) The change in liquid volume due to the effect of pressure on a liquid (Cpl).

(h) *What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?* (1) If you use a mechanical-displacement prover, you must record proof runs until five out of six consecutive runs produce a difference between individual runs of no greater than .05 percent. You must use the average of the five accepted runs to compute the meter factor.

(2) If you use a master meter, you must record proof runs until three consecutive runs produce a total meter

factor difference of no greater than 0.0005. The flow rate through the meters during the proving must be within 10 percent of the rate at which the line meter will operate. The final meter factor is determined by averaging the meter factors of the three runs;

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

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

(i) *Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must I do?* (1) If the difference between the meter factor and the previous factor exceeds 0.0025 it is a malfunction factor, and you must:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Take samples continuously proportional to flow or daily (use the procedure in the applicable chapter of the API MPMS as incorporated by reference in 30 CFR 250.1;

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

(3) Prove allocation meters monthly if they measure 50 or more barrels per day per meter; or

(4) Prove allocation meters quarterly if they measure less than 50 barrels per day per meter;

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

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

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

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

(9) Permit MMS representatives to witness provings.

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

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

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

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

(4) Obtain the volume and other measurement parameters by using correction factors and procedures in the API MPMS as incorporated by reference in 30 CFR 250.1.

§ 250.183 Gas measurement.

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

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

(1) Submit a written application to and obtain approval from the Regional Supervisor before commencing gas production or making changes to previously approved measurement procedures.

(2) Design, install, use, maintain, and test measurement equipment to ensure accurate and verifiable measurement. You must follow the recommendations in API MPMS as incorporated by reference in 30 CFR 250.1.

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

(4) Equip the meter with a chart or electronic data recorder. If an electronic data recorder is used, you must follow the recommendations in API MPMS as referenced in 30 CFR 250.1.

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

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

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

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

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

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

(1) Calibrate meters monthly, but do not exceed 42 days between calibrations;

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

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

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

(5) Permit MMS representatives to witness calibrations.

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

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

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

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

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

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

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

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

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

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

(f) *What are the requirements for measuring gas lost or used on a lease?* (1) You must either measure or estimate the volume of gas lost or used on a lease.

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

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

(4) You must keep the documentation, including the volume data, easily obtainable for inspection at the field location for at least 2 years, and must retain the documentation at a location of your choosing for at least 7 years after the documentation is generated, subject to all other document retention and production requirements in 30 U.S.C. 1713 and 30 CFR part 212.

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

§ 250.184 Surface commingling.

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

(1) Submit a written application to and obtain approval from the Regional Supervisor before commencing the commingling of production or making changes to previously approved commingling applications.

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

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

(1) Conduct a well test at least once every 2 months unless the Regional Supervisor approves a different frequency;

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

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

§ 250.185 Site security.

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

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

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

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

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

(i) Theft or mishandling of production;

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

(iii) Falsifying production measurements.

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

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

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

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

(iii) Temperature and gravity compensation device components;

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

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

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

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

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

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