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Mineral Resources

30

PARTS 200 TO 699

Revised as of July 1, 1997

CONTAINING
A CODIFICATION OF DOCUMENTS
OF GENERAL APPLICABILITY
AND FUTURE EFFECT

AS OF JULY 1, 1997

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Cite this Code: CFR

To cite the regulations in this volume use title, part and section number. Thus, 30 CFR 201.100 *refers to title 30, part 201, section 100.*

Explanation

The Code of Federal Regulations is a codification of the general and permanent rules published in the Federal Register by the Executive departments and agencies of the Federal Government. The Code is divided into 50 titles which represent broad areas subject to Federal regulation. Each title is divided into chapters which usually bear the name of the issuing agency. Each chapter is further subdivided into parts covering specific regulatory areas.

Each volume of the Code is revised at least once each calendar year and issued on a quarterly basis approximately as follows:

Title 1 through Title 16.....as of January 1
Title 17 through Title 27.....as of April 1
Title 28 through Title 41.....as of July 1
Title 42 through Title 50.....as of October 1

The appropriate revision date is printed on the cover of each volume.

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The Paperwork Reduction Act of 1980 (Pub. L. 96–511) requires Federal agencies to display an OMB control number with their information collection request.

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An index to the text of ''Title 3—The President'' is carried within that volume.

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RAYMOND A. MOSLEY,
Director,
Office of the Federal Register.

July 1, 1997.

THIS TITLE

Title 30—MINERAL RESOURCES is composed of three volumes. The parts in these volumes are arranged in the following order: parts 1 to 199, parts 200 to 699, and part 700 to End. The contents of these volumes represent all current regulations codified under this title of the CFR as of July 1, 1997.

Redesignation tables appear in the first and second volumes of title 30.

For this volume, Karen A. Thornton was Chief Editor. The Code of Federal Regulations publication program is under the direction of Frances D. McDonald, assisted by Alomha S. Morris.

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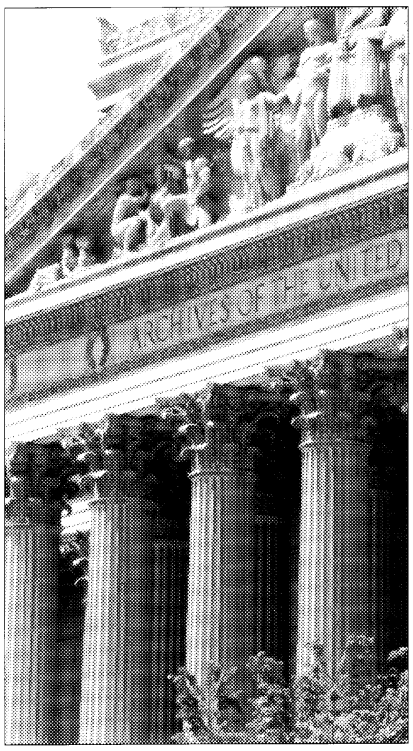

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Title 30—Mineral Resources

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CROSS REFERENCES:

Bureau of Land Management, Department of the Interior, regulations with respect to mineral lands: 43 CFR, chapter II, subchapter C.
Foreign Trade Statistics, Bureau of the Census, Department of Commerce: 15 CFR part 30.
Forest Service regulations relating to mineral developments and mining in national forests: 36 CFR part 228.
General Services Administration regulations for stockpiling of strategic and critical materials: 41 CFR chapter 101, subchapter C.
Interstate Commerce Commission: 49 CFR chapter X.
Bureau of Indian Affairs, Department of the Interior, energy and minerals regulations: 25 CFR chapter I, subchapter I.

EDITORIAL NOTE: Other regulations issued by the Department of the Interior appear in title 25, chapters I and II; title 36, chapter I; title 41, chapter 114; title 43; and title 50, chapters I and IV.

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SUBCHAPTER A—ROYALTY MANAGEMENT

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201.100 Responsibilities of the Associate Director for Royalty Management.

Subpart D—Oil, Gas and Sulphur, Offshore [Reserved]

Subpart E—Coal [Reserved]

Subpart F—Other Solid Minerals [Reserved]

Subpart G—Geothermal Resources [Reserved]

Subpart H—Indian Lands [Reserved]

AUTHORITY: The Act of February 25, 1920 (30 U.S.C. 181, *et seq.*), as amended; the Act of May 21, 1930 (30 U.S.C. 301–306); the Mineral Leasing Act for Acquired Lands (30 U.S.C. 351–359), as amended; the Act of March 3, 1909 (25 U.S.C. 396), as amended; the National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*) as amended; the Act of May 11, 1938 (25 U.S.C. 396a–396q), as amended; the Act of February 28, 1891 (25 U.S.C. 397), as amended; the Act of May 29, 1924 (25 U.S.C. 398); the Act of March 3, 1927 (25 U.S.C. 398a–398e); the Act of June 30, 1919 (25 U.S.C. 399), as amended; R.S. §441 (43 U.S.C. 1457), see also Attorney General's Opinion of April 2, 1941 (40 Op. Atty. Gen. 41); the Federal Property and Administrative Services Act of 1949 (40 U.S.C. 471, *et seq.*), as amended; the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), as amended; the Act of December 12, 1980 (Pub. L. 96–514, 94 Stat. 2964); the Combined Hydrocarbon Leasing Act of 1981 (Pub. L. 97–78, 95 Stat. 1070); the Outer Continental Shelf Lands Act (43 U.S.C. 1331, *et seq.*), as amended; section 2 of Reorganization Plan No. 3 of 1950 (64 stat. 1262); Secretarial Order No. 3071 of January 19, 1982, as amended; and Secretarial Order 3087, as amended.

Subpart A—General Provisions [Reserved]

Subpart B—Oil and Gas, General [Reserved]

Subpart C—Oil and Gas, Onshore

§201.100 Responsibilities of the Associate Director for Royalty Management.

The Associate Director is responsible for the collection of certain rents, royalties, and other payments; for the receipt of sales and production reports; for determining royalty liability; for maintaining accounting records; for any audits of the royalty payments and obligations; and for any and all other functions relating to royalty management on Federal and Indian oil and gas leases.

[47 FR 47768, Oct. 27, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983]

Subpart D—Oil, Gas and Sulphur, Offshore [Reserved]

Subpart E—Coal [Reserved]

Subpart F—Other Solid Minerals [Reserved]

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PART 202—ROYALTIES

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Subpart I—OCS Sulfur [Reserved]

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; 43 U.S.C. 1301 *et seq.*; 1331 *et seq.*, 1801 *et seq.*

Subpart A—General Provisions [Reserved]

Subpart B—Oil, Gas, and OCS Sulfur, General

SOURCE: 53 FR 1217, Jan. 15, 1988, unless otherwise noted.

§ 202.51 Scope and definitions.

(a) This subpart is applicable to Federal and Indian (Tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma) and OCS sulfur leases.

(b) The definitions in subparts C, D, and I of part 206 of this title are applicable to subparts B, C, D, and I of this part.

§ 202.52 Royalties.

(a) Royalties on oil, gas, and OCS sulfur shall be at the royalty rate specified in the lease, unless the Secretary, pursuant to the provisions of the applicable mineral leasing laws, reduces, or in the case of OCS leases, reduces or eliminates, the royalty rate or net profit share set forth in the lease.

(b) For purposes of this subpart, the use of the term *royalty(ies)* includes the term *net profit share(s).*

§ 202.53 Minimum royalty.

For leases that provide for minimum royalty payments, the lessee shall pay the minimum royalty as specified in the lease.

Subpart C—Federal and Indian Oil

§ 202.100 Royalty on oil.

(a) Royalties due on oil production from leases subject to the requirements of this part, including condensate separated from gas without processing, shall be at the royalty rate established by the terms of the lease. Royalty shall be paid in value unless MMS requires payment in-kind. When paid in value, the royalty due shall be the value, for royalty purposes, determined pursuant to part 206 of this title multiplied by the royalty rate in the lease.

(b)(1) All oil (except oil unavoidably lost or used on, or for the benefit of, the lease, including that oil used off-lease for the benefit of the lease when such off-lease use is permitted by the MMS or BLM, as appropriate) produced from a Federal or Indian lease to which this part applies is subject to royalty.

(2) When oil is used on, or for the benefit of, the lease at a production facility handling production from more than one lease with the approval of the MMS or BLM, as appropriate, or at a production facility handling unitized or communitized production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility may be used royalty-free.

(3) Where the terms of any lease are inconsistent with this section, the lease terms shall govern to the extent of that inconsistency.

(c) If BLM determines that oil was avoidably lost or wasted from an onshore lease, or that oil was drained from an onshore lease for which compensatory royalty is due, or if MMS determines that oil was avoidably lost or wasted from an offshore lease, then the value of that oil shall be determined in accordance with 30 CFR part 206.

(d) If a lessee receives insurance compensation for unavoidably lost oil, royalties are due on the amount of that compensation. This paragraph shall not apply to compensation through self-insurance.

(e)(1) In those instances where the lessee of any lease committed to a federally approved unitization or communitization agreement does not actually take the proportionate share of the agreement production attributable to its lease under the terms of the agreement, the full share of production attributable to the lease under the terms of the agreement nonetheless is subject to the royalty payment and reporting requirements of this title. Except as provided in paragraph (e)(2) of this section, the value, for royalty purposes, of production attributable to unitized or communitized leases will be determined in accordance with 30 CFR part 206. In applying the requirements of 30 CFR part 206, the circumstances involved in the actual disposition of the portion of the production to which the lessee was entitled but did not take shall be considered as controlling in arriving at the value, for royalty purposes, of that portion as though the person actually selling or disposing of the production were the lessee of the Federal or Indian lease.

(2) If a Federal or Indian lessee takes less than its proportionate share of agreement production, upon request of the lessee MMS may authorize a royalty valuation method different from that required by paragraph (e)(1) of this section, but consistent with the purposes of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(3) For purposes of this subchapter, all persons actually taking volumes in excess of their proportionate share of production in any month under a unitization or communitization agreement shall be deemed to have taken ratably from all persons actually taking less than their proportionate share of the agreement production for that month.

(4) If a lessee takes less than its proportionate share of agreement production for any month but royalties are paid on the full volume of its proportionate share in accordance with the provisions of this section, no additional royalty will be owed for that lease for prior periods when the lessee subsequently takes more than its proportionate share to balance its account or when the lessee is paid a sum of money by the other agreement participants to balance its account.

(f) For production from Federal and Indian leases which are committed to federally-approved unitization or communitization agreements, upon request of a lessee MMS may establish the value of production pursuant to a method other than the method required by the regulations in this title if: (1) The proposed method for establishing value is consistent with the requirements of the applicable statutes, lease terms, and agreement terms; (2) persons with an interest in the agreement, including, to the extent practical, royalty interests, are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and (3) to the extent practical, persons with an interest in a Federal or Indian lease committed to the agreement, including royalty interests, must agree to use the proposed method for valuing production from the agreement for royalty purposes.

[53 FR 1217, Jan. 15, 1988]

§ 202.101 Standards for reporting and paying royalties.

Oil volumes are to be reported in barrels of clean oil of 42 standard U.S. gallons (231 cubic inches each) at 60°F. When reporting oil volumes for royalty purposes, corrections must have been made for Basic Sediment and Water (BS&W) and other impurities. Reported American Petroleum Institute (API) oil gravities are to be those determined in accordance with standard industry procedures after correction to 60°F.

[53 FR 1217, Jan. 15, 1988]

Subpart D—Federal and Indian Gas

SOURCE: 53 FR 1271, Jan. 15, 1988, unless otherwise noted.

§ 202.150 Royalty on gas.

(a) Royalties due on gas production from leases subject to the requirements of this subpart, except helium produced from Federal leases, shall be at the rate established by the terms of the lease. Royalty shall be paid in value unless MMS requires payment in kind. When paid in value, the royalty due shall be the value, for royalty purposes, determined pursuant to 30 CFR part 206 of this title multiplied by the royalty rate in the lease.

(b)(1) All gas (except gas unavoidably lost or used on, or for the benefit of, the lease, including that gas used off-lease for the benefit of the lease when such off-lease use is permitted by the MMS or BLM, as appropriate) produced from a Federal or Indian lease to which this subpart applies is subject to royalty.

(2) When gas is used on, or for the benefit of, the lease at a production facility handling production from more than one lease with the approval of MMS or BLM, as appropriate, or at a production facility handling unitized or communitized production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility may be used royalty free.

(3) Where the terms of any lease are inconsistent with this subpart, the lease terms shall govern to the extent of that inconsistency.

(c) If BLM determines that gas was avoidably lost or wasted from an onshore lease, or that gas was drained from an onshore lease for which compensatory royalty is due, or if MMS determines that gas was avoidably lost or wasted from an OCS lease, then the value of that gas shall be determined in accordance with 30 CFR part 206.

(d) If a lessee receives insurance compensation for unavoidably lost gas, royalties are due on the amount of that compensation. This paragraph shall not apply to compensation through self-insurance.

(e)(1) In those instances where the lessee of any lease committed to a Federally approved unitization or communitization agreement does not actually take the proportionate share of the production attributable to its Federal or Indian lease under the terms of the agreement, the full share of production attributable to the lease under the terms of the agreement nonetheless is subject to the royalty payment and reporting requirements of this title. Except as provided in paragraph (e)(2) of this section, the value for royalty purposes of production attributable to unitized or communitized leases will be determined in accordance with 30 CFR part 206. In applying the requirements of 30 CFR part 206, the circumstances involved in the actual disposition of the portion of the production to which the lessee was entitled but did not take shall be considered as controlling in arriving at the value for royalty purposes of that portion, as if the person actually selling or disposing of the production were the lessee of the Federal or Indian lease.

(2) If a Federal or Indian lessee takes less than its proportionate share of agreement production, upon request of the lessee MMS may authorize a royalty valuation method different from that required by paragraph (e)(1) of this section, but consistent with the purpose of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(3) For purposes of this subchapter, all persons actually taking volumes in excess of their proportionate share of production in any month under a unitization or communitization agreement shall be deemed to have taken ratably from all persons actually taking less than their proportionate share of the agreement production for that month.

(4) If a lessee takes less than its proportionate share of agreement production for any month but royalties are paid on the full volume of its proportionate share in accordance with the provisions of this section, no additional royalty will be owed for that lease for prior periods at the time the lessee subsequently takes more than its proportionate share to balance its account or when the lessee is paid a sum of

money by the other agreement participants to balance its account.

(f) For production from Federal and Indian leases which are committed to federally-approved unitization or communitization agreements, upon request of a lessee MMS may establish the value of production pursuant to a method other than the method required by the regulations in this title if: (1) The proposed method for establishing value is consistent with the requirements of the applicable statutes, lease terms and agreement terms; (2) to the extent practical, persons with an interest in the agreement, including royalty interests, are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and (3) to the extent practical, persons with an interest in a Federal or Indian lease committed to the agreement, including royalty interests, must agree to use the proposed method for valuing production from the agreement for royalty purposes.

§ 202.151 Royalty on processed gas.

(a)(1) A royalty, as provided in the lease, shall be paid on the value of:

(i) Any condensate recovered downstream of the point of royalty settlement without resorting to processing; and

(ii) Residue gas and all gas plant products resulting from processing the gas produced from a lease subject to this subpart.

(2) MMS shall authorize a processing allowance for the reasonable, actual costs of processing the gas produced from Federal and Indian leases. Processing allowances shall be determined in accordance with 30 CFR part 206 subpart D for gas production from Federal leases and 30 CFR part 206 subpart E for gas production from Indian leases.

(b) A reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 CFR part 206. In those situations where a processing plant processes gas from more than one lease, only that proportionate share of each lease's residue gas necessary for the operation of the processing plant shall be allowed royalty free.

(c) No royalty is due on residue gas, or any gas plant product resulting from processing gas, which is reinjected into a reservoir within the same lease, unit area, or communitized area, when the reinjection is included in a plan of development or operations and the plan has received BLM or MMS approval for onshore or offshore operations, respectively, until such time as they are finally produced from the reservoir for sale or other disposition off-lease.

[53 FR 1217, Jan. 15, 1988, as amended at 61 FR 5490, Feb. 12, 1996]

§ 202.152 Standards for reporting and paying royalties on gas.

(a)(1) Gas volumes and Btu heating values, if applicable, shall be determined under the same degree of water saturation. Gas volumes shall be reported in units of one thousand cubic feet (mcf), and Btu heating value shall be reported at a rate of Btu's per cubic foot, at a standard pressure base of 14.73 pounds per square inch absolute (psia) and a standard temperature base of 60 °F, except that for OCS leases in the Gulf of Mexico, gas volumes and Btu heating values shall be reported at a standard pressure base of 15.025 psia and a standard temperature base of 60 °F. Gas volumes and Btu heating values shall be reported, for royalty purposes, on the same water vapor saturated or unsaturated basis prescribed by Federal Energy Regulatory Commission (FERC) regulation, or on the basis prescribed in the lessee's gas sales contract provided that the sales contract does not conflict with FERC regulation.

(2) The frequency and method of Btu measurement as set forth in the lessee's contract shall be used to determine Btu heating values for reporting purposes. However, the lessee shall measure the Btu value at least semi-annually by recognized standard industry testing methods even if the lessee's contract provides for less frequent measurement.

(b)(1) Residue gas and gas plant product volumes shall be reported as specified in this paragraph.

(2) Carbon dioxide (CO_2), nitrogen (N_2), helium (He), residue gas, and any

other gas marketed as a separate product shall be reported by using the same standards specified in paragraph (a) of this section.

(3) Natural gas liquids (NGL) volumes shall be reported in standard U.S. gallons (231 cubic inches) at 60 °F.

(4) Sulfur (S) volumes shall be reported in long tons (2,240 pounds).

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal

§ 202.250 Overriding royalty interest.

The regulations governing overriding royalty interests, production payments, or similar interests created under Federal coal leases are in 43 CFR group 3400.

[54 FR 1522, Jan. 13, 1989]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources

SOURCE: 56 FR 57275, Nov. 8, 1991, unless otherwise noted.

§ 202.350 Scope and definitions.

(a) This subpart is applicable to all geothermal resources produced from Federal geothermal leases issued pursuant to the Geothermal Steam Act of 1970, as amended (30 U.S.C. 1001 *et seq.).*

(b) The definitions in 30 CFR 206.351 are applicable to this subpart.

§ 202.351 Royalties on geothermal resources.

(a) Royalties on geothermal resources, including byproduct minerals and commercially demineralized water, shall be at the royalty rate(s) specified in the lease, unless the Secretary of the Interior temporarily waives, suspends, or reduces that rate(s). Royalties shall be paid in value. The royalty due shall be the value determined pursuant to subpart H of 30 CFR part 206 multiplied by the royalty rate in the lease.

(b)(1) Royalties are due on all geothermal resources, except those specified in paragraph (b)(2) of this section, that are produced from a lease and are sold or utilized by the lessee or are reasonably susceptible to sale or utilization by the lessee.

(2) Geothermal resources that are unavoidably lost, as determined by the Bureau of Land Management (BLM), and geothermal resources that are reinjected prior to use on or off the lease, as approved by BLM, are not subject to royalty. The Minerals Management Service (MMS) will allow free of royalty a reasonable amount of geothermal energy necessary to generate electricity for internal powerplant operations or to generate electricity returned to the lease for lease operations. If a powerplant uses geothermal production from more than one lease, or uses unitized or communitized production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the powerplant may be used royalty free. The MMS will also allow free of royalty a reasonable amount of commercially demineralized water necessary for powerplant operations or otherwise used on or for the benefit of the lease.

(3) Royalties on byproducts are due at the time the recovered byproduct is used, sold, or otherwise finally disposed of. Byproducts produced and added to stockpiles or inventory do not require payment of royalty until the byproducts are sold, utilized, or otherwise finally disposed of. The MMS may ask BLM to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventories become excessive.

(c) If BLM determines that geothermal resources (including byproducts) were avoidably lost or wasted from the lease, or that geothermal resources (including byproducts) were drained from the lease for which compensatory royalty is due, the value of those geothermal resources shall be determined in accordance with subpart H of 30 CFR part 206.

(d) If a lessee receives insurance or other compensation for unavoidably lost geothermal resources (including byproducts), royalties at the rates specified in the lease are due on the amount of that compensation. This

paragraph shall not apply to compensation through self-insurance.

§ 202.352 Minimum royalty.

In no event shall the lessee's annual royalty payments for any producing lease be less than the minimum royalty established by the lease.

§ 202.353 Measurement standards for reporting and paying royalties.

(a) For geothermal resources used to generate electricity, the quantity on which royalty is due shall be reported on Form MMS–2014 (Report of Sales and Royalty Remittance) as follows:

(1) For geothermal resources valued under arm's-length or non-arm's-length contracts, quantities shall be reported in:

(i) Kilowatthours to the nearest whole kilowatthour if the contract specifies payment in terms of generated electricity,

(ii) Thousands of pounds to the nearest whole thousand pounds if the contract specifies payment in terms of weight, or

(iii) Millions of Btu's to the nearest whole million Btu if the contract specifies payment in terms of heat or thermal energy.

(2) For geothermal resources valued by the netback procedure pursuant to 30 CFR 206.352(c)(1)(ii) or (d)(1)(ii), the quantities shall be reported in kilowatthours to the nearest whole kilowatthour.

(b) For geothermal resources used in direct utilization processes, the quantity on which royalty is due shall be reported on Form MMS–2014 in:

(1) Millions of Btu's to the nearest whole million Btu if valuation is in terms of thermal energy used or displaced,

(2) Hundreds of gallons to the nearest hundred gallons of geothermal fluid produced if valuation is in terms of volume, or

(3) Other measurement unit approved by MMS for valuation and reporting purposes.

(c) For byproduct minerals, the quantity on which royalty is due shall be reported on Form MMS–2014 consistent with MMS-established reporting standards.

(d) For commercially demineralized water, the quantity on which royalty is due shall be reported on Form MMS–2014 in hundreds of gallons to the nearest hundred gallons.

(e) Lessees are not required to report the quality of geothermal resources, including byproducts, to MMS. The lessee must maintain quality measurements for audit and valuation purposes. Quality measurements include, but are not limited to, temperatures and chemical analyses for fluid geothermal resources and chemical analyses, weight percent, or other purity measurements for byproducts.

Subpart I—OCS Sulfur—[Reserved]

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

Subpart A—General Provisions

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203.251 Reduction in royalty rate or rental.

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

AUTHORITY: 25 U.S.C. 396 *et seq.*; 25 U.S.C. 396a *et seq.*; 25 U.S.C. 2101 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq.*; 30 U.S.C. 1001 *et seq.*; 30 U.S.C. 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*; 43 U.S.C. 1331 *et seq.*; and 43 U.S.C. 1801 *et seq.*

Subpart A—General Provisions

SOURCE: 61 FR 27274, May 31, 1996, unlesss otherwise noted.

§ 203.1 Authority for information collection.

(a) The Office of Management and Budget (OMB) approved the information collection requirements in part 203 under 44 U.S.C. 3501 *et seq.* and assigned OMB control number 1010–0071. The MMS uses the information to determine whether granting a royalty relief request will result in the production of resources that would not be produced without such relief. The application for royalty relief must contain sufficient financial, economic, reservoir, geologic and geophysical, production, and engineering data and information to determine whether relief should be granted in accordance with applicable law. the application also must contain sufficient data and information to determine whether the requested relief will result in an ultimate increase in resource recovery and provide for reasonable returns on project investments. The applicant's requirement to respond is related only to the request to obtain royalty relief. The applicant has no obligation to make this request.

(b) An agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number.

(c) Send comments regarding the burden of this information collection or any other aspect of the collection of information under provisions of this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer; Minerals Management Service, Mail Stop 2300, 381 Elden Street; Herndon, Virginia 20170–4817 and the Office of Management and Budget; Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of the Interior (1010–0071); Washington, DC 20503.

(d) The MMS will protect information considered confidential or proprietary under applicable law and under regulations at § 203.53(b)(ii) and part 250 of this chapter.

Subpart B—OCS Oil, Gas, and Sulfur, General

SOURCE: 61 FR 27274, May 31, 1996, unless otherwise noted.

§ 203.50 Definitions.

Terms used in this part have the following meaning:

Field means an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both.

Pre-enactment deep-water lease (PDWL) means an Outer Continental Shelf (OCS) lease issued as a result of a lease sale held before November 28, 1995. The lease must be in a water depth of at least 200 meters and in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude.

Project to significantly expand production (PSEP) means a project proposed in an approved Supplemental Development Operations Coordination Document (DOCD) that will result in an increase in ultimate recovery of resources from the field and that involves a substantial capital investment (e.g., the addition of a fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well projects). The project must be on a PDWL.

Sunk costs means costs (as specified in § 203.55) of exploration, development, and production incurred after the date of first discovery on the field and prior to the date of application for royalty relief. Sunk costs also include the costs

of the discovery well qualified as producible under 30 CFR 250.11.

§ 203.51 What is MMS's authority to grant royalty relief?

Under the OCS Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act, Public Law 104–58, MMS may grant three types of royalty relief listed in this section.

(a) Under 43 U.S.C. 1337(a)(3)(A), MMS may reduce, suspend, or eliminate the royalty specified for any producing OCS lease to promote increased production. If your OCS lease has inadequate revenues to sustain production or if you are proposing a project to expand production that would be uneconomic without royalty relief, MMS may grant royalty relief as specified in these regulations at § 203.52 (Net Revenue Share Royalty Relief).

(b) Under 43 U.S.C. 1337(a)(3)(B), MMS may grant royalty reductions or suspensions to promote development, increase production, or encourage production of marginal resources on producing or non-producing leases in the Gulf of Mexico, west of 87 degrees, 30 minutes West longitude. Section 203.54 is reserved for the regulations to implement this provision.

(c) Under 43 U.S.C. 1337(a)(3)(C), if your PDWL is on a field that did not produce before November 28, 1995, or if you have a PDWL where you propose a PSEP, MMS may suspend royalties for volumes of new production which would be uneconomic without royalty relief as specified in these regulations in § 203.53 (Royalty relief for certain deep-water leases in the Gulf of Mexico).

§ 203.52 Net revenue share royalty relief.

(a) *How do I apply for net revenue share (NRS) royalty relief?*

This section explains how to obtain royalty relief under 43 U.S.C. 1337(a)(3)(A) if your lease has inadequate revenues to sustain production or if you are proposing a project to expand production that would be uneconomic without royalty relief. To apply for relief, submit a complete application to the appropriate MMS Regional Director in accordance with this section and the applicable guidelines in § 203.52(b) and § 203.55. An application fee in accordance with § 203.56 must accompany the application.

(b) *What do I need to include in my application?*

(1) A complete application for royalty relief must include an original and two copies of:

(i) Administrative Information and Relief Justification, and

(ii) Net Revenue Share Economic Viability Report.

(2) If you are proposing a project to expand production that would be uneconomic without royalty relief, your application must also include two copies (one set of digital information) of:

(i) Geologic and Geophysical Report;

(ii) Production Report; and

(iii) Engineering Report.

(3) Section 203.55 describes the reports required for the complete application. The appropriate regional office will provide specific guidance on the format for the required reports.

(c) *What are the NRS royalty relief approval criteria?*

(1) MMS may grant your request for royalty relief only if it concludes that royalty relief will increase the ultimate recovery of hydrocarbons by extending lease production for at least one year. However, if you are proposing a project to expand production, MMS will approve your request for royalty relief only if the proposed project would be uneconomic without royalty relief.

(2) If you have a lease with inadequate revenues to sustain production, MMS may grant your request for royalty relief only if it concludes that:

(i) Royalties paid to MMS over the most recent 12-month period exceed 75 percent of net revenues; and

(ii) Royalties are projected to take an increasing share of net revenues over the next 12 months.

(d) *What royalty relief will MMS grant?*

(1) Except as provided in paragraph (d)(2) of this section, if you meet the royalty relief criteria of this section, MMS may offer to modify the royalty terms of your lease to a NRS. The percentage of the net revenue due to MMS will be established in the MMS NRS guidelines available in the appropriate Regional Office.

(2) If you are proposing a project to expand production but no amount of royalty relief would make the project economic, MMS will deny the request for royalty relief.

§ 203.53 Royalty relief for certain deep-water leases in the Gulf of Mexico.

(a) *Who may apply for deep-water royalty relief?*

This section explains how to obtain royalty relief under 43 U.S.C. 1337(a)(3)(C). You may apply for royalty relief if you are a lessee of a PDWL or a unit that contains one or more PDWL's, subject to the limitation in paragraph (b)(3) of this section. You may apply for relief if:

(1) your lease or unit is part of a field from which no royalties were due on production, other than test production, prior to November 28, 1995; or

(2) you are proposing a PSEP.

(b) *How do I apply for deep-water royalty relief?*

(1) You must submit a complete application to the MMS Regional Director of the Gulf of Mexico OCS Region. An application fee in accordance with § 203.56 must accompany the application.

(2) A complete application includes an original and two copies (one set of digital information) of:

(i) Administrative Information and Relief Justification;

(ii) Deep-Water Royalty Relief Economic Viability Report;

(iii) Deep-Water Royalty Relief Cost Report;

(iv) Geologic and Geophysical Report;

(v) Production Report; and

(vi) Engineering Report.

Section 203.55 describes what these reports must include. The Gulf of Mexico Regional Office will provide specific guidance on the format for the required reports.

(3) For a royalty suspension on production from fields from which no royalties were due on production, other than test production, before November 28, 1995:

(i) Except as provided in paragraph (b)(3)(iii) of this section, MMS will accept only one joint application for all leases that are part of the field on the date of application. The Regional Director maintains a list of all leases in each discovered field.

(ii) If a lessee does not want to share proprietary data with other lessees on the field, that lessee may submit separately to MMS the proprietary geological or geophysical data that is a necessary part of the joint application. The application is not complete until MMS receives all the required information for each lease on the field. In explaining its assumptions and reasons for its determinations under this section, MMS will not disclose proprietary data.

(iii) MMS will waive the joint application requirement if the applicant(s) shows good cause for the waiver. The applicant also must demonstrate that it made a good faith effort to obtain the participation of all lessees in the field. A lease that is part of the field on the date of application but that is not included in the application because its lessee(s) fails or refuses to participate is not eligible for the royalty relief for the field that is the subject of the application. However, that lessee still may apply for other royalty relief under this section.

(iv) With the exceptions listed below, the lessees on a field may submit only one complete application for royalty relief during the life of the field. However, lessees may submit another application if:

(A) They are eligible to apply for a redetermination under § 203.53(d)(1);

(B) MMS has withdrawn approval of a previously granted royalty suspension under § 203.53(e);

(C) They apply for royalty relief for a PSEP; or

(D) They withdraw the application before MMS deems it complete.

(c) *How will MMS evaluate an application?*

(1)(i) MMS will determine within 20 working days if your application for royalty relief is complete. If your application is incomplete, MMS will provide you with an explanation of what it needs to become complete. If you withdraw your application after MMS has deemed it complete, you may only reapply under the redetermination provision of § 203.53(d).

(ii) When MMS determines that your application is complete, MMS will

evaluate the application within 180 days. MMS may extend the 180-day evaluation period for an additional 30 days, if necessary, to complete the evaluation. If you agree, MMS also may extend the 180-day period for more than 30 days.

(iii) If MMS must audit sunk costs to evaluate your application, MMS may request that the 180-day evaluation period be tolled from the time you receive notice from MMS until you provide the records necessary to conduct the audit.

(iv) If MMS determines during the evaluation period that it cannot evaluate your application because:

(A) vital information is missing;

(B) the data and information provided in support of the application are inconclusive; or

(C) of any other valid reason;

MMS may request that the 180-day evaluation period be tolled from the time you receive notice from MMS until you provide needed data, explanations, or revisions.

(2)(i) If your application is for a suspension of royalties on production from a field from which no royalties were due on production, other than test production, before November 28, 1995, MMS will determine if development of the field is economic without royalty relief. MMS will include your sunk costs in making this determination. If MMS determines that development of the field would be economic without relief, MMS will deny your request for a royalty suspension.

(ii) For fields that did produce, other than test production, before the date of application, MMS will not include your sunk costs when it determines if development of the field is economic without royalty relief. If MMS determines that development of the field would be economic without relief, MMS will deny your request for a royalty suspension.

(iii) If MMS determines for a field subject to either paragraph (c)(2) (i) or (ii) of this section that development of the field would not be economic without a royalty suspension, and that a royalty suspension could make the project economic, MMS will determine the size of the royalty suspension volume necessary to make the field economically viable. MMS will determine your royalty suspension volume subject to the minimum royalty suspension volumes specified in paragraph (h)(1)(i) of this section. MMS will not include sunk costs when it makes this determination.

(iv) If no amount of royalty suspension would make the field economic, MMS will deny your request for royalty relief.

(3)(i) If your application for royalty relief is for a PSEP, MMS will determine if the proposed project is economic without royalty relief. If it is economic, MMS will deny your request for royalty relief.

(ii) If MMS determines that development of the project would not be economic without royalty relief, MMS will determine the royalty suspension volume necessary to make the project economically viable.

(iii) If no amount of royalty suspension volume would make the project economic, MMS will deny your request for royalty relief.

(iv) MMS will not include sunk costs in evaluating applications for royalty relief for a PSEP.

(4) If MMS approves your application for royalty relief, you must submit a pre-production report 60 days before the planned start of production which is subject to the royalty suspension volume, as specified at § 203.55.

(d) *When will MMS reconsider its determination?*

(1) You may request a redetermination of either a denial of an application or the size of the royalty suspension volume granted in an approved application. However, you may request a redetermination only if you have not started producing hydrocarbons subject to the royalty suspension and one of the following situations occurs:

(i) You have significant new geologic or geophysical data that did not exist at the time of the previous application and that causes you to change your estimates of gross resource size, quality, or projected flow rates. Examples of new data include results from drilling new wells or obtaining new three-dimensional seismic data and information. Reinterpretation of existing data is not significant new data. The change

in resource information must be sufficient to materially affect the results of the previous determination.

(ii) Prices for oil or gas have decreased at least 25 percent, determined as follows:

(A) Calculate the arithmetic average of daily closing prices for light sweet crude oil and for natural gas on the New York Mercantile Exchange (NYMEX) for the most recent 12 months.

(B) Calculate the weighted average prices for oil and gas calculated under (d)(1)(ii)(A) of this section using the volumes of oil and gas identified in the most likely scenario (required under § 203.55) described in your previous complete application for royalty relief.

(C) Perform the same calculations as required in paragraphs (d)(1)(ii) (A) and (B) of this section, but use the arithmetic average of daily closing prices for light sweet crude oil and for natural gas on the NYMEX for the 12-month period preceding the date of your previous complete application.

(D) If the weighted average price calculated under paragraph (d)(1)(ii)(B) of this section is at least 25 percent less than the weighted average price calculated under paragraph (d)(1)(ii)(C) of this section, then you satisfy the requirements of this paragraph; or

(iii) Prior to starting construction of your development/production system, you have revised your estimated development costs, and they are at least 120 percent of the eligible development costs associated with the most likely scenario described in your previous complete application.

(2)(i) Your request for a redetermination must include a new complete application, as discussed in paragraph (b) of this section and § 203.55. MMS will evaluate your application for a redetermination under paragraph (c) of this section.

(ii) MMS will determine within 20 working days if your application for a redetermination is complete. If your application is incomplete, MMS will provide you with an explanation of what it needs to become complete. If MMS later determines that your application does not meet any of the criteria under (d)(1) (i), (ii), or (iii) of this section, it will consider your application incomplete.

(iii) When MMS determines that your application is complete, MMS will evaluate the application within 120 days. MMS may extend the 120-day evaluation period for an additional 30 days if necessary to complete the evaluation. If you agree, MMS also may extend the 120-day period for more than 30 days.

(iv) If MMS must audit sunk costs to evaluate your application, MMS may request that the 120-day evaluation period be tolled from the time you receive notice from MMS until you provide the records necessary to conduct the audit.

(v) If MMS determines during the evaluation period that it cannot evaluate your application because:

(A) Vital information is missing;

(B) The data and information provided in support of the application are inconclusive; or

(C) Of any other valid reason;

MMS may request that the 120-day evaluation period be tolled from the time you receive notice from MMS until you provide the needed data, explanations, or revisions.

(e) *When may MMS withdraw approval of an application for royalty relief?*

MMS will withdraw approval of your application for royalty relief if:

(1) You change the type of development system proposed in your approved application (e.g., change from stand-alone to tieback or vice versa);

(2) You fail to start construction of the approved development/production system within two years of the date MMS approved your application—notwithstanding any suspension granted under § 250.10 of this chapter; or

(3)(i) The actual development costs reported in your pre-production report (paragraph (c)(4) of this section) are less than 80 percent of the development costs from the date of application to the date of the pre-production report associated with the most likely scenario described in your approved application. In this case, you may retain 50 percent of the amount of the royalty suspension volume that MMS previously granted.

(ii) If MMS granted you a royalty suspension volume after you requested

a redetermination under paragraph (d)(1)(iii) of this section, MMS may withdraw approval of your application for a royalty suspension if your actual development costs in your pre-production report (paragraph (c)(4) of this section) are less than 90 percent of the eligible development costs from the date of application to the date of the pre-production report associated with the most likely scenario described in your approved application.

(iii) If MMS discovers that the actual development costs are less than the amounts specified in paragraphs (e)(3)(i) or (ii) of this section, MMS will withdraw retroactively its approval of the royalty suspension volume. You will owe royalties and interest on all production that was subject to the previously granted royalty suspension.

(4) If MMS determines that you provided false historical or intentionally inaccurate information that was material to MMS in granting royalty relief under this section, MMS will rescind its approval as of the date of the approval. You must pay royalties and late payment interest determined under 30 U.S.C. 1721 and § 218.54 of this chapter on all volumes for which you used the royalty suspension. You also may be subject to penalties under other provisions of law.

(5) If MMS withdraws its approval of a royalty suspension for any of the reasons in paragraphs (e) (1), (2) or (3) of this section, you may apply again for relief under paragraph (b) of this section and § 203.55.

(f) *What happens if MMS fails to accept or reject my application in a timely manner?*

(1) For applications for fields from which no royalties were due on production, other than test production, prior to November 28, 1995, if MMS does not make its determinations on your application within the time period specified in paragraph (c)(1) or (d)(1) of this section, including any applicable extension, you will receive the minimum royalty suspension volumes specified in paragraph (h)(1)(i) of this section.

(2) For PSEP applications, if MMS does not make its determinations on your application within the time period specified in paragraph (c)(1) or (d)(2) of this section, including any applicable extension, you will receive a royalty suspension for the first year of the project's production.

(g) *How do I appeal an MMS decision under § 203.53?*

(1) MMS' decision whether to grant deep-water royalty relief and its decision on the size of the royalty suspension volume are final agency actions. You have no right to further administrative review, including Secretarial review, of these decisions. The MMS's decisions are judicially reviewable under section 10(a) of the Administrative Procedure Act (5 U.S.C. 702) only if you file an action within 30 days of the date you receive MMS's decision. MMS's will send its decision to you by certified mail, return receipt requested.

(2)(i) Except as provided in paragraph (g)(2)(ii) of this section, MMS decisions on designating a lease as part of a field are final agency actions.

(ii) If MMS designates your lease as part of a field, within 15 days of such designation you may file a written request with the Director for reconsideration accompanied by a statement of reasons. The Director will respond in writing either affirming or reversing the decision. The Director's decision is the final decision of the Department.

(h) *How does a royalty suspension volume apply to your production?*

This paragraph explains how the royalty suspension volumes in section 302 of the OCS Deep Water Royalty Relief Act, apply to production from PDWL's. For purposes of this paragraph, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter do not count against royalty suspension volumes. Also, for purposes of this paragraph, production includes volumes allocated to a lease under an approved unit agreement. The following provisions apply only to those leases for which the lessee(s) applies for and receives a royalty suspension volume under this section.

(1) For fields from which no royalties were due on production, other than test production, prior to November 28, 1995:

(i) The water depth of a lease is based on the water depth delineations in the

''Royalty Suspension Areas Map'' in effect at the time of your application. If the application for the field includes leases in different water depth categories, the minimum royalty volume associated with the deepest lease applies. The minimum royalty suspension volumes are: (A) 17.5 million barrels of oil equivalent (MMBOE) in 200 to 400 meters of water; (B) 52.5 MMBOE in 400 to 800 meters of water; and (C) 87.5 MMBOE in more than 800 meters of water.

(ii) If your PDWL is the only lease on the field, you do not owe royalty on the production from your lease up to the royalty suspension volume MMS granted.

(iii) If a field consists of more than one PDWL, payment of royalties on the PDWLs' production is suspended until their cumulative production equals the royalty suspension volume MMS granted. The royalty suspension volume for each lease equals each lease's actual production (or production allocated under an approved unit agreement) until cumulative production equals the field's royalty suspension volume.

(iv) If a PDWL or an eligible lease, as defined in § 260.102 of this chapter, is added to a field for which MMS has granted a royalty suspension volume under this section, the field's royalty suspension volume will not change. The additional lease may receive a royalty suspension volume only to the extent of its production from the field before the cumulative production from the field equals the royalty suspension volume MMS approved. However, before your PDWL may participate in the royalty suspension volume already granted to the field, you must apply for royalty relief using an abbreviated form available at the Gulf of Mexico OCS Regional Office.

(v) If your PDWL is part of a field that already has a royalty suspension volume for eligible leases under § 260.110 of this chapter, and you apply and qualify for royalty relief under this section, all the leases in the field share a single royalty suspension volume that is the greater of the volume established for the eligible leases under § 260.110 of this chapter or the volume MMS determines under this section.

(2) For a PSEP:

(i) If your PDWL is the only lease included in the project, you do not owe royalty on the incremental production from the project up to the royalty suspension volume MMS granted.

(ii) If the project includes more than one lease, the royalty suspension volume for each lease equals each lease's actual incremental production from the project (or production allocated under an approved unit agreement) until cumulative incremental production for all leases in the project equals the project's royalty suspension volume.

(3) Your lease may receive more than one royalty suspension volume. You may apply for royalty relief under this section for each field that includes your lease, and each field would receive a separate royalty suspension volume if it meets the evaluation criteria of paragraph 203.53(c). You may also apply for relief for a PSEP, even if MMS has already granted a royalty suspension volume to the field that encompasses that project.

(4) You may receive a royalty suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude. A field that lies on both sides of this meridian will receive a royalty suspension volume only for those leases lying entirely west of the meridian.

(5) You must measure natural gas production subject to the royalty suspension volume as follows: 5.62 thousand cubic feet of natural gas equals one barrel of oil equivalent, as measured at 15.025 psi, 60 degrees Fahrenheit, and fully saturated.

(6)(i) If in the previous calendar year the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil exceeds $28.00 per barrel, as adjusted in paragraph (h)(8) of this section, the royalty relief authorized in this section is suspended and any production of oil is subject to royalties at the lease stipulated royalty rate. However, this production counts as part of the established royalty suspension volume. By January 31 of the current calendar year, you must pay the royalty due plus interest, in accordance with 30 U.S.C 1721 and § 218.54 of this chapter, on any volume of oil

from the previous year for which you did not pay royalty.

(ii) If the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil from the previous calendar year exceeds $28.00 per barrel, as adjusted in paragraph (h)(8) of this section, you must pay royalties on all your oil production in the current year. If the arithmetic average of the daily closing prices on the NYMEX for light sweet crude oil for the current calendar year is $28.00 per barrel or less, as adjusted in paragraph (h)(8) of this section, you are entitled to a refund or credit, with interest, of royalties paid that year on any royalty suspension volume for oil production. You must follow MMS regulations at part 230 of this chapter for receiving refunds or credits.

(7)(i) If in the previous calendar year the arithmetic average of the daily closing prices on the NYMEX for natural gas exceeds $3.50 per million British thermal units, as adjusted in paragraph (h)(8) of this section, the royalty relief authorized in this section is suspended and any production of natural gas is subject to royalties at the lease stipulated royalty rate. However, this production counts as part of the established royalty suspension volume. By January 31 of the current calendar year, you must pay the royalty due plus interest, in accordance with 30 U.S.C 1721 and § 218.54 of this chapter, on any volume of natural gas from the previous year for which you did not pay royalty.

(ii) If the arithmetic average of the daily closing prices on the NYMEX for natural gas for the previous calendar year exceeds $3.50 per million British thermal units, as adjusted in paragraph (h)(8) of this section, you must pay royalties on all your natural gas production in the current year. If the arithmetic average of the daily closing prices on the NYMEX for natural gas for the current calendar year is $3.50 per million British thermal units or less, as adjusted in paragraph (h)(8) of this section, you are entitled to a refund or credit, with interest, of royalties paid that year on any royalty suspension volume for natural gas production. You must follow MMS regulations at part 230 of this chapter for receiving refunds or credits.

(8) Change the prices referred to in paragraphs (h)(6) and (7) of this section during each calendar year after 1994 by the percentage, if any, by which the implicit price deflator for the gross domestic product changed during the preceding calendar year.

(9) A royalty suspension volume will continue until the end of the month in which the cumulative production from the field or PSEP reaches the established royalty suspension volume.

§ 203.54 [Reserved]

§ 203.55 What information is required for the net revenue share royalty relief and deep-water royalty relief application supplemental reports?

(a) You must submit the applicable supplemental reports listed below.

(1) *Administrative information and relief justification.* All royalty relief applications must contain this report, which must include:

(i) Field name;

(ii) Serial number of leases in the field, names of the lease the titleholders of record, the lease operators, and the identification of whether any lease is part of a unit;

(iii) The API number and location of each well that has been drilled on the field/lease or project;

(iv) Location of any new wells proposed under the terms of the application;

(v) Description of field/lease history;

(vi) Statement that the reserves would not be produced without relief;

(vii) Full information as to whether royalties or payment out of production will be paid to anyone other than the United States, the amount to be paid, and the amount of reduction in such payment if relief is granted;

(viii) Amount of relief needed to make the lease *(NRS royalty relief),* field *(deep-water royalty relief),* or project economic;

(ix) Confirmation that MMS approved a DOCD or supplemental DOCD *(NRS expansion of production and deep-water royalty relief application only);* and

(x) A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of

the activities and the effect on production *(NRS expansion of production and deep-water royalty relief application only)*.

(2) *Net revenue share economic viability report.* NRS royalty relief applications must contain this report. This report must present cash flow data, including 36 months of historical data and 12 months of projected data, for the following items:

(i) Lease production subject to royalty;

(ii) Total revenues;

(iii) Royalty payments out of production;

(iv) Operating costs;

(v) Transportation and processing costs;

(vi) Capital expenditures (if applicable); and

(vii) Well drilling costs (if applicable).

(3) *Deep-water royalty relief economic viability report.* This report should demonstrate that the project appears economic without royalties and sunk costs using the model provided by MMS. A company may provide supplemental information, including its own model and model results. This report must include all of the items listed below.

(i) Economic assumptions provided by MMS:

(A) Starting oil and gas prices;

(B) Real price growth;

(C) Real cost growth or decline rate, if any;

(D) Base year;

(E) Range of discount rates; and

(F) Tax rate (for use in determining after-tax sunk costs).

(ii) Projected cash flow analysis (from application date using annual totals and constant dollar values). All costs, gross production, and scheduling must be consistent with the data in the reserve, engineering, production, and cost reports, and the three scenarios (conservative, most likely, optimistic; provided in the various reports must be consistent with each other and the proposed development system. The analysis must show:

(A) Oil/gas production;

(B) Total revenues;

(C) Capital expenditures;

(D) Operating costs;

(E) Transportation costs; and

(F) Before tax net cash flow.

(iii) Discounted values.

(A) Discount rate used (selected from within range provided in MMS guidelines).

(B) Before tax net present value without royalties, overrides, sunk costs, and ineligible costs.

(4) *Deep-water royalty relief cost report.* Deep-water royalty relief applications must contain this report. Report all actual and projected costs listed in this paragraph in the format detailed in the guidelines.

(i) Sunk costs. This includes all eligible costs, in current dollars and for which documentation is provided, actually incurred subsequent to and including the first discovery well on the field. Sunk costs count on an after-tax, expensed basis, using nominal (current dollar) amounts.

(ii) Delineation and development costs, based on actual costs or current authorization for expenditures. These costs include:

(A) Platform well drilling costs and average depth;

(B) Platform well completion costs;

(C) Subsea well drilling costs and average depth;

(D) Subsea well completion costs;

(E) Production system (platform) costs; and

(F) Flowline fabrication and installation costs.

(iii) Production costs, based on historical costs, engineering estimates, or analogous projects. These costs include:

(A) Operating costs;

(B) Equipment costs; and

(C) Existing royalty overrides (MMS will not use the royalty overrides in its evaluation).

(iv) Transportation costs, based on historical costs, engineering estimates, or analogous projects. These costs include:

(A) Oil and/or gas tariffs from pipeline or tankerage;

(B) Trunkline/tieback line costs; and

(C) Gas plant processing costs for NGL's.

(v) Ineligible costs. These costs include:

(A) Acquisition costs;

(B) Application fees;

(C) Prospective exploration well costs;

(D) Costs associated with obligations existing prior to the application; and

(E) Other ineligible costs listed in § 203.55(b).

(vi) Uncertainty. You must provide a cost scenario consistent with each one of the three field development and production profiles (conservative, most likely, optimistic). Express costs in constant real dollar terms for the base year. You may also express the uncertainty of each cost scenario as a minimum and maximum percentage of the base value.

(vii) Scheduling. Provide costs on an annual basis (in real dollars) for each of the categories in paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(viii) Abandonment. Provide the costs to plug and abandon wells and to remove production systems for which costs have not been incurred at the time of application.

(ix) Pre-production report. You must file a pre-production report 60 days before the start of the production subject to an approved royalty suspension. For each of the cost categories in the deep-water royalty relief cost report, you must include actual costs up to the date when the pre-production report is submitted. Retain supporting records for these costs and make them available to MMS upon request.

(5) *Geologic and geophysical report.* Deep-water royalty relief and NRS production expansion proposal applications must contain this report. This report must include all of the items listed below.

(i) Seismic data:

(A) Non-interpreted 2D/3D survey lines (8mm tape) (SEGY format or IES format);

(B) Interpreted 2D/3D seismic survey lines identifying all known and prospective pay horizons, wells, and fault cuts;

(C) Digital velocity surveys in format of LTL 10/1/90;

(D) Plat map of ''shot points;'' and

(E) ''Time slices'' of potential horizons.

(ii) Well data.

(A) Hard copies of all well logs.

(*1*) One-inch electric log must show:

(*i*) pay zones and pay counts; and

(*ii*) lithologic and paleo correlation markers at least every 500 ft.

(*2*) One-inch type log must show missing sections from other logs where faulting occurs.

(*3*) Five-inch electric log must show:

(*i*) pay zones and pay counts; and

(*ii*) labeled points used in establishing Ro and Rt.

(*4*) Five-inch porosity logs must show:

(*i*) pay zones and pay counts; and

(*ii*) labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulky density or transit time.

(B) Digital copies of all well logs spudded before December 1, 1995.

(C) Core data, if available.

(D) Well correlation sections.

(E) Pressure data.

(F) Production test results.

(G) PVT analysis, if available.

(iii) Map interpretations. For each reservoir included in the application, you must submit:

(A) Structure maps and top and base of sand maps showing well and seismic shot point locations;

(B) Isopach maps for net sand, net oil, net gas, all with well locations;

(C) Maps indicating well surface and bottom hole locations, location of development facilities, and shot points; and

(D) Identification of reservoirs not contemplated for development.

(iv) Reservoir data. For each reservoir included in the application, you must identify and submit:

(A) Oil and/or gas reserve/resource distribution;

(B) Probability of reservoir occurrence with hydrocarbons;

(C) Probability the hydrocarbon in the reservoir is oil, and the probability it is gas;

(D) Distributions for the parameters used to estimate the resources, i.e. acre, net thickness, recovery, porosity, salt water saturation, formation volume factor;

(E) Aggregated BOE reserve/resource for the field;

(F) Gas/oil ratio distribution for each reservoir;

(G) Yield distribution for each gas reservoir;

(H) Description of anticipated crude quality (e.g., gravity); and

(I) Points on the aggregated reserve/resource distribution used for the determination of the three (conservative, most likely, optimistic) production profiles specified in the production report.

(6) *Production report.* Deep-water royalty relief and NRS production expansion proposal applications must contain this report, which must include all of the items listed below.

(i) Production profile. Submit actual and projected (BOE) production by year for each of the following products: oil, condensate, gas, and associated gas.

(ii) Uncertainty *(deep-water royalty relief only).* Submit three production profiles as described in paragraph (a)(6)(i) of this section. Each one must be consistent with a specific point on the aggregated reserve/resource distribution and must represent a conservative, most likely, and an optimistic case.

(iii) Production drive mechanisms for each reservoir.

(iv) Quality adjustments to prices for gravity, sulfur, etc.

(7) *Engineering report.* Deep-water royalty relief and NRS production expansion proposal applications must contain this report. However, NRS expanded production applications should submit this information only as it relates to the planned development. This report must include all of the items listed below.

(i) Development concept:

(A) Tension leg platform, fixed, floater type, subsea tieback, etc.; and

(B) Construction schedule.

(ii) Planned wells:

(A) Number of wells planned;

(B) Type of well (platform, subsea, vertical, deviated, horizontal);

(C) Well depth;

(D) Drilling schedule;

(E) Completion description (single, dual, horizontal, etc.); and

(F) Completion schedule.

(iii) Production system equipment:

(A) Production capacity for oil and gas and a description of its limiting component(s);

(B) Unusual problems (low gravity, high sulfur content, etc.);

(C) Subsea structures;

(D) Flowlines; and

(E) Production system installation schedule.

(iv) Multi-phase development plans;

(A) Conceptual basis for developing in phases and goals/milestones required for commencing subsequent phases; and

(B) Justification for the exclusion of reservoirs not contemplated for development.

(v) Uncertainty. Submit schedules for development consistent with each of the three field production profiles (conservative, most likely, optimistic) provided in the production report.

(b) Ineligible costs. MMS will not include certain costs in making its royalty relief determinations. These include, but are not limited to:

(1) Costs incurred before first discovery on the field;

(2) Cash bonuses;

(3) Royalty relief application fees;

(4) Lease rentals, royalties, and net profit share and net revenue share payments;

(5) Legal expenses;

(6) Damages and losses;

(7) Taxes;

(8) Interest or finance charges;

(9) Fines or penalties;

(10) Designated well costs, including prospective exploration and delineation costs; and

(11) Costs associated with prior existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease, expenditures for plugging wells and removal and abandonment of facilities existing on the date of the application).

(c) The applicant or the applicant's authorized representative must certify that all information submitted in an application or a pre-production report is accurate and complete. The application or pre-production report must be accompanied by a report prepared by an independent certified public accountant (CPA) expressing an unqualified opinion on the accuracy of the actual historical financial information presented in the application or pre-production report and that the presentation of data and information conforms to the MMS guidelines. The applicant will make the independent CPA available to the MMS to respond to

questions which may arise regarding the evaluation of the historical information. This requirement does not limit the MMS's ability to conduct further review of the applicant's records to support the historical financial information included in the application.

§ 203.56 Recovery of application processing costs.

When you submit an application for royalty relief, you must include a payment to reimburse MMS for the costs it incurs in processing your application. The MMS will establish in a Notice to Lessees a schedule that will specify the fees that must be paid for each of the different types of royalty relief applications. Regional Directors will periodically update the fee schedule to reflect changes in MMS costs as well as to provide other information necessary for the administration of our royalty relief program.

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal

§ 203.250 Advance royalty.

Provisions for the payment of advance royalty in lieu of continued operation are contained at 43 CFR 3483.4.

[54 FR 1522, Jan. 13, 1989]

§ 203.251 Reduction in royalty rate or rental.

An application for reduction in coal royalty rate or rental shall be filed and processed in accordance with 43 CFR group 3400.

[54 FR 1522, Jan. 13, 1989]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

PART 206—PRODUCT VALUATION

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Subpart G—Other Solid Minerals

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206.354 Determination of generating deductions.
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206.356 Valuation standards for byproducts.
206.357 Byproduct transportation allowances—general.
206.358 Determination of byproduct transportation allowances.

Subpart I—OCS Sulfur [Reserved]

Subpart J—Indian Coal

206.450 Purpose and scope.
206.451 Definitions.
206.452 Coal subject to royalties—general provisions.
206.453 Quality and quantity measurement standards for reporting and paying royalties.
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206.462 Contract submission.
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206.464 Value enhancement of marketable coal.

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.; 43 U.S.C. 1301 *et seq.,* 1331 *et seq.,* and 1801 *et seq.*

Subpart A—General Provisions

§ 206.10 Information collection.

The information collection requirements contained in this part have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 et seq. The forms, filing date, and approved OMB clearance numbers are identified in 30 CFR 210.10.

[57 FR 41863, Sept. 14, 1992]

Subpart B—Indian Oil

SOURCE: 61 FR 5455, Feb. 12, 1996, unless otherwise noted.

§ 206.50 Purpose and scope.

(a) This subpart is applicable to all oil production from Indian (Tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma). The purpose of this subpart is to establish the value of production, for royalty purposes, consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) If the specific provisions of any Federal statute, treaty, settlement agreement between the Indian lessor and a lessee resulting from administrative or judicial litigation, or oil and gas lease subject to the requirements of this subpart are inconsistent with any regulation in this subpart, then the statute, treaty, lease provision or

settlement agreement shall govern to the extent of that inconsistency.

(c) All royalty payments made to MMS or Indian Tribes are subject to audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian oil and gas leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

§ 206.51 Definitions.

For the purposes of this subpart:

Allowance means an approved or an MMS-initially accepted deduction in determining value for royalty purposes. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving oil to a point of sale or point of delivery off the lease, unit area, or communitized area, excluding gathering, or an approved or MMS-initially accepted deduction for costs of such transportation, determined by this subpart.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

Arm's-length contract means a contract or agreement that has been arrived at in the market place between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: ownership in excess of 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates. Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month, as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Indian leases.

BIA means the Bureau of Indian Affairs of the Department of the Interior.

BLM means the Bureau of Land Management of the Department of the Interior.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located.

Gathering means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off the lease, unit, or communitized area as approved by BLM operations personnel for onshore leases.

Gross proceeds (for royalty payment purposes) means the total monies and other consideration accruing to an oil

and gas lessee for the disposition of the oil produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as dehydration, measurement, and/or gathering to the extent that the lessee is obligated to perform them at no cost to the Indian lessor. Gross proceeds, as applied to oil, also includes, but is not limited to, reimbursements for harboring or terminating fees. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Indian allottee means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context.

Lease products means any leased minerals attributable to, originating from, or allocated to Indian leases.

Lessee means any person to whom an Indian Tribe, or an Indian allottee issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

Like-quality lease products means lease products which have similar chemical, physical, and legal characteristics.

Load oil means any oil which has been used with respect to the operation of oil or gas wells for wellbore stimulation, workover, chemical treatment, or production purposes. It does not include oil used at the surface to place lease production in marketable condition.

Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

Marketing affiliate means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

Minimum royalty means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

MMS means the Minerals Management Service of the Department of the Interior.

Net-back method (or workback method) means a method for calculating market value of oil at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the oil and any extracted, processed, or manufactured products, or from the value of the oil or any extracted, processed, or manufactured products at the first point at which reasonable values for any such products may be determined by a sale under an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

Net profit share (for applicable Indian lessees) means the specified share of the net profit from production of oil and gas as provided in the agreement.

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and is marketed or used as such. Condensate recovered in lease separators or field facilities is considered to be oil. For purposes of royalty valuation, the term tar sands is defined separately from oil.

Oil shale means a kerogen-bearing rock (i.e., fossilized, insoluble, organic

material). Separation of kerogen from oil shale may take place in situ or in surface retorts by various processes. The kerogen, upon distillation, will yield liquid and gaseous hydrocarbons.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Posted price means the price specified in publicly available posted price bulletins, onshore terminal postings, or other price notices net of all adjustments for quality (e.g., API gravity, sulfur content, etc.) and location for oil in marketable condition.

Processing means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

Selling arrangement means the individual contractual arrangements under which sales or dispositions of oil are made. Selling arrangements are described by illustration in MMS Royalty Management Program Oil and Gas Payor Handbook.

Spot sales agreement means a contract wherein a seller agrees to sell to a buyer a specified amount of oil at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

Tar sands means any consolidated or unconsolidated rock (other than coal, oil shale, or gilsonite) that either contains a hydrocarbonaceous material with a gas-free viscosity greater than 10,000 centipoise at original reservoir temperature, or contains quarrying.

§ 206.52 Valuation standards.

(a)(1) The value of production, for royalty purposes, of oil from leases subject to this subpart shall be the value determined under this section less applicable allowances determined under this subpart.

(2)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value for royalty purposes, if data are available to compute a major portion, MMS will, where practicable, compare the value determined in accordance with this section with the major portion. The value to be used in determining the value of production, for royalty purposes, shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of oil production from the same field. The major portion will be calculated using like-quality oil sold under arm's-length contracts from the same field (or, if necessary to obtain a reasonable sample, from the same area) for each month. All such oil production will be arrayed from highest price to lowest price (at the bottom).

The major portion is that price at which 50 percent (by volume) plus 1 barrel of the oil (starting from the bottom) is sold.

(b)(1)(i) The value of oil which is sold under an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (b)(1)(iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, oil which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate under an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the oil. If the contract does not reflect the total consideration, then MMS may require that the oil sold

under that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If MMS determines that the gross proceeds accruing to the lessee under an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between two contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the oil production be valued under the first applicable of paragraph (c)(2), (c)(3), (c)(4), or (c)(5) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value. If the oil production is then valued under paragraph (c)(4) or (c)(5) of this section, the notification requirements of paragraph (e) of this section shall apply.

(2) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the oil.

(c) The value of oil production from leases subject to this section which is not sold under an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following paragraphs:

(1) The lessee's contemporaneous posted prices or oil sales contract prices used in arm's-length transactions for purchases or sales of significant quantities of like-quality oil in the same field (or, if necessary to obtain a reasonable sample, from the same area); provided, however, that those posted prices or oil sales contract prices are comparable to other contemporaneous posted prices or oil sales contract prices used in arm's-length transactions for purchases or sales of significant quantities of like-quality oil in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of posted prices or oil sales contract prices, the following factors shall be considered: Price, duration, market or markets served, terms, quality of oil, volume, and other factors as may be appropriate to reflect the value of the oil. If the lessee makes arm's-length purchases or sales at different postings or prices, then the volume-weighted average price for the purchases or sales for the production month will be used;

(2) The arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee for purchases or sales of significant quantities of like-quality oil in the same field (or, if necessary to obtain a reasonable sample, from the same area);

(3) The arithmetic average of other contemporaneous arm's-length contract prices for purchases or sales of significant quantities of like-quality oil in the same area or nearby areas;

(4) Prices received for arm's-length spot sales of significant quantities of like-quality oil from the same field (or, if necessary to obtain a reasonable sample, from the same area), and other relevant matters, including information submitted by the lessee concerning circumstances unique to a particular lease operation or the salability of certain types of oil;

(5) A net-back method or any other reasonable method to determine value;

(6) For purposes of this paragraph, the term lessee includes the lessee's designated purchasing agent, and the term contemporaneous means postings or contract prices in effect at the time the royalty obligation is incurred.

(d) Any Indian lessee will make available, upon request to the authorized MMS or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased, or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(e)(1) Where the value is determined under paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent

with the requirements of these regulations.

(2) A lessee shall notify MMS if it has determined value under paragraph (c)(4) or (c)(5) of this section. The notification shall be by letter to MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c)(4) or (c)(5) of this section and each time there is a change from one to the other of these two methods.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on the difference computed under 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method and may use that value for royalty payment purposes until MMS issues a value determination. The lessee shall submit all available data relevant to its proposal. MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production, for royalty purposes, be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances determined under this subpart.

(i) The lessee is required to place oil in marketable condition at no cost to the Indian lessor unless otherwise provided in the lease agreement or this section. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the oil in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of oil.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Indian Tribes or allottees until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified

by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable laws and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information to which such lessor may be lawfully entitled from MMS or such lessor's lessee directly under the terms of the lease, 30 U.S.C. 1733, or other applicable law.

§ 206.53 Point of royalty settlement.

(a)(1) Royalties shall be computed on the quantity and quality of oil as measured at the point of settlement approved by BLM for onshore leases.

(2) If the value of oil determined under § 206.52 of this subpart is based upon a quantity and/or quality different from the quantity and/or quality at the point of royalty settlement approved by the BLM for onshore leases, the value shall be adjusted for those differences in quantity and/or quality.

(b) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such actual loss is determined to have been unavoidable by BLM.

(c) Except as provided in paragraph (b) of this section, royalties are due on 100 percent of the volume measured at the approved point of royalty settlement. There can be no reduction in that measured volume for actual losses beyond the approved point of royalty settlement or for theoretical losses that are claimed to have taken place either prior to or beyond the proved point of royalty settlement. Royalties are due on 100 percent of the value of the oil as provided in this subpart. There can be no deduction from the value of the oil for royalty purposes to compensate for actual losses beyond the approved point of royalty settlement or for theoretical losses that are claimed to have taken place either prior to or beyond the approved point of royalty settlement.

§ 206.54 Transportation allowances—general.

(a) Where the value of oil has been determined under Section 206.52 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable, actual costs incurred by the lessee to transport oil to a point off the lease; provided, however, that no transportation allowance will be granted for transporting oil taken as Royalty-In-Kind (RIK); or

(b)(1) Except as provided in paragraph (b)(2) of this section, the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the oil at the point of sale as determined under § 206.52 of this subpart. Transportation costs cannot be transferred between selling arrangements or to other products.

(2) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitation prescribed by paragraph (b)(1) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitation prescribed in paragraph (b)(1) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances shall the value, for royalty purposes, under any selling arrangement, be reduced to zero.

(c) Transportation costs must be allocated among all products produced and transported as provided in § 206.55. Transportation allowances for oil shall be expressed as dollars per barrel.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest determined in accordance with 30 CFR

218.54, or shall be entitled to a credit, without interest.

§ 206.55 Determination of transportation allowances.

(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee under an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting oil under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. Such allowances shall be subject to the provisions of paragraph (f) of this section. Before any deduction may be taken, the lessee must submit a completed page one of Form MMS–4110 (and Schedule 1), Oil Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4110 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one liquid product, and the transportation costs attributable to each product cannot be determined from the contract, then the total transportation costs shall be allocated in a consistent and equitable manner to each of the liquid products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty-bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the oil transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all available data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS approves a longer period). MMS shall then determine the oil transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(4) Where the lessee's payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, the lessee shall convert whatever

consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price, or a posted price, includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable, actual costs as provided in this paragraph. All transportation allowances deducted under a non-arms-length or no-contract situation are subject to monitoring, review, audit, and adjustment. Before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS–4110 in its entirety in accordance with paragraph (c)(2) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4110 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. MMS will monitor the allowance deductions to determine whether lessees are taking deductions that are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its actual transportation allowance deduction.

(2) The transportation allowance for non-arms-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial capital investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services or on a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (b)(2)(v) of this

section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined under paragraph (c) of this section).

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, allocation of costs to each of the liquid products transported shall be in the same proportion as the ratio of the volume of each liquid product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value) and such allocation shall be made in a consistent and equitable manner. Except as provided in this paragraph, the lessee may not take an allowance for transporting lease production which is not royalty-bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the oil transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all available data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS approves a longer period). MMS shall then determine the oil transportation allowance on the basis of the lessee's proposal and any additional information MMS deems necessary.

(5) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) for Indian leases. MMS shall deny the exception request if it determines that the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if:

(i) No FERC cost analysis exists and the FERC has declined to investigate under MMS timely objections upon filing; and

(ii) the tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS–4110 (and Schedule 1), Oil Transportation Allowance Report, prior to, or at the same time as, the transportation allowance determined, under an arm's-length contract, is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4110 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received.

(ii) The initial Form MMS–4110 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue

until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS–4110 (and Schedule 1) within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v), (c)(2)(vii) and (c)(2)(viii) of this section, the lessee shall submit an initial Form MMS–4110 prior to, or at the same time as, the transportation allowance determined under a non-arm's-length contract or no-contract situation is reported on Form MMS–2014. A Form MMS–4110 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received. The initial report may be based upon estimated costs.

(ii) The initial Form MMS–4110 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until transportation under the non-arm's-length contract or the no-contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS–4110 containing the actual costs for the previous reporting period. If oil transportation is continuing, the lessee shall include on Form MMS–4110 its estimated costs for the next calendar year. The estimated oil transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases that will affect the allowance. MMS must receive the Form MMS–4110 within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS–4110 shall include estimates of the allowable oil transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no-contract transportation allowances which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS–4110. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If the lessee is authorized to use its FERC-approved tariff as its transportation cost in accordance with paragraph (b)(5) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) MMS may establish reporting dates for individual lessees different from those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on Form MMS–2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and for failure to report.* (1) If a lessee deducts a transportation allowance on its Form MMS–2014 without complying with the requirements of this section, the lessee shall pay interest only on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed under 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from Indian leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts, no cost shall be allowed for oil transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or State regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a netback valuation procedure or any other procedure that requires deduction of transportation costs.

Subpart C—Federal Oil

SOURCE: 53 FR 1218–1222, Jan. 15, 1988, unless otherwise noted.

§ 206.100 Purpose and scope.

(a) This subpart is applicable to all oil production from Federal oil and gas leases. The purpose of this subpart is to establish the value of production, for royalty purposes, consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) If the specific provisions of any Federal statute, settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or oil and gas lease subject to the requirements of this subpart are inconsistent with any regulation in this subpart, then the statute, lease provision or settlement agreement shall govern to the extent of that inconsistency.

(c) All royalty payments made to MMS are subject to audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian oil and gas leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

[53 FR 1218–1222, Jan. 15, 1988, as amended at 61 FR 5462, Feb. 12, 1996]

§ 206.101 Definitions.

For the purposes of this subpart:

Allowance means a deduction in determining value for royalty purposes. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving oil to a point of sale or point of delivery off the lease, unit area, or communitized area, excluding gathering.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

Arm's-length contract means a contract or agreement that has been arrived at in the market place between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(a) Ownership in excess of 50 percent constitutes control;

(b) Ownership of 10 through 50 percent creates a presumption of control; and

(c) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month, as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

BLM means the Bureau of Land Management of the Department of the Interior.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located. Outer Continental Shelf (OCS) fields are named and their boundaries are designated by MMS.

Gathering means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off the lease, unit, or communitized area as approved by BLM or MMS OCS operations personnel for onshore and offshore leases, respectively.

Gross proceeds (for royalty payment purposes) means the total moneys and other consideration accruing to an oil and gas lessee for the disposition of the oil produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as dehydration, measurement, and/or gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds, as applied to oil, also includes, but is not limited to, reimbursements for harboring or terminaling fees. Tax reimbursements are part of the gross proceeds accruing to a lessee even

though the Federal royalty interest may be exempt from taxation. Moneys and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context.

Lease products means any leased minerals attributable to, originating from, or allocated to Outer Continental Shelf or onshore Federal leases.

Lessee means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

Like-quality lease products means lease products which have similar chemical, physical, and legal characteristics.

Load oil means any oil which has been used with respect to the operation of oil or gas wells for wellbore stimulation, workover, chemical treatment, or production purposes. It does not include oil used at the surface to place lease production in marketable condition.

Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

Marketing affiliate means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

Minimum royalty means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

Net-back method (or workback method) means a method for calculating market value of oil at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the oil and any extracted, processed, or manufactured products, or from the value of the oil or any extracted, processed, or manufactured products at the first point at which reasonable values for any such products may be determined by a sale pursuant to an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

Net profit share (for applicable Federal leases) means the specified share of the net profit from production of oil and gas as provided in the agreement.

Netting is the deduction of an allowance from the sales value by reporting a one line net sales value, instead of correctly reporting the deduction as a separate line item on the Form MMS–2014.

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and is marketed or used as such. Condensate recovered in lease separators or field facilities is considered to be oil. For purposes of royalty valuation, the term tar sands is defined separately from oil.

Oil shale means a kerogen-bearing rock (i.e., fossilized, insoluble, organic material). Separation of kerogen from oil shale may take place in situ or in surface retorts by various processes. The kerogen, upon distillation, will yield liquid and gaseous hydrocarbons.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Posted price means the price specified in publicly available posted price bulletins, offshore or onshore terminal postings, or other price notices net of all adjustments for quality (e.g., API gravity, sulfur content, etc.) and location for oil in marketable condition.

Processing means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

Section 6 lease means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

Selling arrangement means the individual contractual arrangements under which sales or dispositions of oil are made. Selling arrangements are described by illustration in the MMS Royalty Management Program (Oil and Gas or Solid Minerals) Payor Handbook.

Spot sales agreement means a contract wherein a seller agrees to sell to a buyer a specified amount of oil at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

Tar sands means any consolidated or unconsolidated rock (other than coal, oil shale, or gilsonite) that either contains a hydrocarbonaceous material with a gas-free viscosity greater than 10,000 centipoise at original reservoir temperature, or contains a hydrocarbonaceous material and is produced by mining or quarrying.

[53 FR 1218–1222, Jan. 15, 1988, as amended at 53 FR 45084, Nov. 8, 1988; 61 FR 5462, Feb. 12, 1996]

§ 206.102 Valuation standards.

(a) The value of production, for royalty purposes, of oil from leases subject to this subpart shall be the value determined pursuant to this section less applicable allowances determined pursuant to this subpart.

(b)(1)(i) The value of oil which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, oil which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the oil. If the contract does not reflect the total consideration, then the MMS may require that the oil sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between two contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the oil production be valued pursuant to the first applicable of paragraph (c) (2), (3), (4), or (5) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value. If the oil production is then valued pursuant to paragraph (c)(4) or (c)(5) of this section, the notification requirements of paragraph (e) of this section shall apply.

(2) The MMS may require a lessee to certify that its arm's-length contract

provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the oil.

(c) The value of oil production from leases subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following paragraphs:

(1) The lessee's contemporaneous posted prices or oil sales contract prices used in arm's-length transactions for purchases or sales of significant quantities of like-quality oil in the same field (or, if necessary to obtain a reasonable sample, from the same area); provided, however, that those posted prices or oil sales contract prices are comparable to other contemporaneous posted prices or oil sales contract prices used in arm's-length transactions for purchases or sales of significant quantities of like-quality oil in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of posted prices or oil sales contract prices, the following factors shall be considered: Price, duration, market or markets served, terms, quality of oil, volume, and other factors as may be appropriate to reflect the value of the oil. If the lessee makes arm's-length purchases or sales at different postings or prices, then the volume-weighted average price for the purchases or sales for the production month will be used;

(2) The arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee for purchases or sales of significant quantities of like-quality oil in the same field (or, if necessary to obtain a reasonable sample, from the same area);

(3) The arithmetic average of other contemporaneous arm's-length contract prices for purchases or sales of significant quantities of like-quality oil in the same area or nearby areas;

(4) Prices received for arm's-length spot sales of significant quantities of like-quality oil from the same field (or, if necessary to obtain a reasonable sample, from the same area), and other relevant matters, including information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain types of oil;

(5) A net-back method or any other reasonable method to determine value;

(6) For purposes of this paragraph, the term lessee includes the lessee's designated purchasing agent, and the term contemporaneous means postings or contract prices in effect at the time the royalty obligation is incurred.

(d) Any Federal lessee will make available, upon request to the authorized MMS or State representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased, or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) A lessee shall notify MMS if it has determined value pursuant to paragraph (c)(4) or (c)(5) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c)(4) or (c)(5) of this section and each time there is a change from one to the other of these two methods.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on the difference computed pursuant to 30 CFR

218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method and may use that value for royalty payment purposes until MMS issues a value determination. The lessee shall submit all available data relevant to its proposal. MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production, for royalty purposes, be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances determined pursuant to this subpart.

(i) The lessee is required to place oil in marketable condition at no cost to the Federal Government unless otherwise provided in the lease agreement or this section. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the oil in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of oil.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable laws and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[53 FR 1213–1222, Jan. 15, 1988, as amended at 53 FR 45762, Nov. 14, 1988; 61 FR 5462, Feb. 12, 1996]

§ 206.103 Point of royalty settlement.

(a)(1) Royalties shall be computed on the quantity and quality of oil as measured at the point of settlement approved by BLM or MMS for onshore and offshore leases, respectively.

(2) If the value of oil determined pursuant to § 206.102 of this subpart is based upon a quantity and/or quality different from the quantity and/or quality at the point of royalty settlement approved by the BLM for onshore leases or the MMS for offshore leases, the value shall be adjusted for those differences in quantity and/or quality.

(b) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such actual loss is determined to have been unavoidable by BLM or MMS, as appropriate.

(c) Except as provided in paragraph (b) of this section, royalties are due on 100 percent of the volume measured at the approved point of royalty settlement. There can be no reduction in that measured volume for actual losses beyond the approved point of royalty settlement or for theoretical losses that are claimed to have taken place either prior to or beyond the approved point of royalty settlement. Royalties are due on 100 percent of the value of the oil as provided in this part. There can be no deduction from the value of the oil for royalty purposes to compensate for actual losses beyond the approved point of royalty settlement or for theoretical losses that are claimed to have taken place either prior to or beyond the approved point of royalty settlement.

§ 206.104 Transportation allowances—general.

(a) Where the value of oil has been determined pursuant to § 206.102 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable, actual costs incurred by the lessee to:

(1) Transport oil from an onshore lease to the point off the lease; *Provided, however,* That for onshore leases, no transportation allowance will be granted for transporting oil taken as Royalty-In-Kind (RIK); or

(2) Transport oil from an offshore lease to the point off the lease; provided, however, that for oil taken as RIK, a transportation allowance shall be provided for the reasonable actual costs incurred to transport that oil to the delivery point specified in the contract between the RIK oil purchaser and the Federal Government.

(b)(1) Except as provided in paragraph (b)(2) of this section, the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the oil at the point of sale as determined pursuant to § 206.102 of this subpart. Transportation costs cannot be transferred between selling arrangements or to other products.

(2) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitation prescribed by paragraph (b)(1) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitation prescribed in paragraph (b)(1) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances shall the value, for royalty purposes, under any selling arrangement, be reduced to zero.

(c) Transportation costs must be allocated among all products produced and transported as provided in § 206.105. Transportation allowances for oil shall be expressed as dollars per barrel.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest determined in accordance with 30 CFR 218.54, or shall be entitled to a credit, without interest. If the lessee takes a deduction for transportation on the Form MMS–2014 by improperly netting the allowance against the sales value of the oil instead of reporting the allowance as a separate line item, the lessee may be assessed an amount under § 206.105(d).

[53 FR 1218–1222, Jan. 15, 1988; 53 FR 24688, June 30, 1988; 53 FR 45762, Nov. 14, 1988; 61 FR 5463, Feb. 12, 1996]

§ 206.105 Determination of transportation allowances.

(a)*Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee under an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting oil under that contract, except

as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. Such allowances shall be subject to the provisions of paragraph (f) of this section. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one liquid product, and the transportation costs attributable to each product cannot be determined from the contract, then the total transportation costs shall be allocated in a consistent and equitable manner to each of the liquid products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty-bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. The MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the oil transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all available data to support its proposal. The initial proposal must be submitted within 3 months after the last day of the month for which the lessee requests a transportation allowance. MMS shall then determine the oil transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(4) Where the lessee's payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price, or a posted price, includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation

services for itself, the transportation allowance will be based upon the lessee's reasonable, actual costs as provided in this paragraph. All transportation allowances deducted under a non-arms-length or no-contract situation are subject to monitoring, review, audit, and adjustment to ensure that they are reasonable and allowable. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arms-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial capital investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services or on a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, allocation of costs to each of the liquid products transported shall be in the same proportion as the ratio of the volume of each liquid product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value) and such allocation shall be

made in a consistent and equitable manner. Except as provided in this paragraph, the lessee may not take an allowance for transporting lease production which is not royalty-bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to the MMS a cost allocation method on the basis of the values of the products transported. The MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the oil transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all available data to support its proposal. MMS shall then determine the oil transportation allowance on the basis of the lessee's proposal and any additional information MMS deems necessary. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on the Form MMS–2014.

(5) A lessee may apply to the MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. The MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) (for both Federal and Indian leases) or a State regulatory agency (for Federal leases). The MMS shall deny the exception request if it determines that the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if: (i) No FERC or State regulatory agency cost analysis exists and the FERC or State regulatory agency, as applicable, has declined to investigate pursuant to MMS timely objections upon filing; and (ii) the tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS–2014.

(ii) The MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract.* (i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on the Form MMS–2014.

(ii) For new transportation facilities or arrangements, the lessee's initial deduction shall include estimates of the allowable oil transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(iv) If the lessee is authorized to use its FERC-approved or State regulatory agency-approved tariff as its transportation cost in accordance with paragraph (b)(5) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest and assessments.* (1) If a lessee nets a transportation allowance against the royalty value on the Form MMS–2014, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed $250 per lease selling arrangement per sales period.

(2) If a lessee deducts a transportation allowance on its Form MMS–2014 that exceeds 50 percent of the value of the oil transported without obtaining prior approval of MMS under 206.104 of this subpart, the lessee shall pay interest on the excess allowance

amount taken from the date such amount is taken to the date the lessee files an exception request with MMS.

(3) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(4) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.54 from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts, no cost shall be allowed for oil transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or State regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a netback valuation procedure or any other procedure that requires deduction of transportation costs.

[53 FR 1218–1222, Jan. 15, 1988, as amended at 53 FR 45762, Nov. 14, 1988; 61 FR 5463, Feb. 12, 1996]

§ 206.106 Operating allowances.

Notwithstanding any other provisions in these regulations, an operating allowance may be used for the purpose of computing payment obligations when specified in the notice of sale and the lease. The allowance amount or formula shall be specified in the notice of sale and in the lease agreement.

[61 FR 3804, Feb. 2, 1996]

Subpart D—Federal Gas

SOURCE: 53 FR 1272, Jan. 15, 1988, unless otherwise noted.

§ 206.150 Purpose and scope.

(a) This subpart is applicable to all gas production from Federal oil and gas leases. The purpose of this subpart is to establish the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws and lease terms.

(b) If the specific provisions of any statute or settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or oil and gas lease subject to the requirements of this subpart are inconsistent with any regulation in this subpart, then the lease, statute, or settlement agreement shall govern to the extent of that inconsistency.

(c) All royalty payments made to MMS are subject to audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the administration of oil and gas leases is discharged in accordance with the requirements of the governing mineral leasing laws and lease terms.

[61 FR 5464, Feb. 12, 1996]

§ 206.151 Definitions.

For purposes of this subpart:

Allowance means a deduction in determining value for royalty purposes. Processing allowance means an allowance for the reasonable costs for processing gas determined under this subpart. Transportation allowance means an allowance for the cost of moving royalty bearing substances (identifiable, measurable oil and gas, including gas that is not in need of initial separation) from the point at which it is first

identifiable and measurable to the sales point or other point where value is established under this subpart.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

Arm's-length contract means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(a) Ownership in excess of 50 percent constitutes control;

(b) Ownership of 10 through 50 percent creates a presumption of control; and

(c) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

BLM means the Bureau of Land Management of the Department of the Interior.

Compression means the process of raising the pressure of gas.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located. Outer Continental Shelf (OCS) fields are named and their boundaries are designated by MMS.

Gas means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

Gas plant products means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

Gathering means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.

Gross proceeds (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of the oil produced. Gross proceeds includes, but is not limited to, payments to the

lessee for certain services such as dehydration, measurement, and/or gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds, as applied to oil, also includes, but is not limited to, reimbursements for harboring or terminaling fees. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context.

Lease products means any leased minerals attributable to, originating from, or allocated to Outer Continental Shelf or onshore Federal leases.

Lessee means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

Like-quality lease products means lease products which have similar chemical, physical, and legal characteristics.

Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

Marketing affiliate means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

Minimum royalty means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

Net-back method (or work-back method) means a method for calculating market value of gas at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, or from the value of the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale pursuant to an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

Net output means the quantity of residue gas and each gas plant product that a processing plant produces.

Net profit share (for applicable Federal leases) means the specified share of the net profit from production of oil and gas as provided in the agreement.

Netting is the deduction of an allowance from the sales value by reporting a one line net sales value, instead of correctly reporting the deduction as a separate line item on the Form MMS–2014.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Posted price means the price, net of all adjustments for quality and location, specified in publicly available price bulletins or other price notices available as part of normal business operations for quantities of unprocessed gas, residue gas, or gas plant products in marketable condition.

Processing means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption,

adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

Residue gas means that hydrocarbon gas consisting principally of methane resulting from processing gas.

Section 6 lease means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

Selling arrangement means the individual contractual arrangements under which sales or dispositions of gas, residue gas and gas plant products are made. Selling arrangements are described by illustration in the MMS Royalty Management Program Oil and Gas Payor Handbook.

Spot sales agreement means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

Warranty contract means a long-term contract entered into prior to 1970, including any amendments thereto, for the sale of gas wherein the producer agrees to sell a specific amount of gas and the gas delivered in satisfaction of this obligation may come from fields or sources outside of the designated fields.

[53 FR 1272, Jan. 15, 1988, as amended at 53 FR 45084, Nov. 8, 1988; 61 FR 5464, Feb. 12, 1996]

§ 206.152 Valuation standards—unprocessed gas.

(a)(1) This section applies to the valuation of all gas that is not processed and all gas that is processed but is sold or otherwise disposed of by the lessee pursuant to an arm's-length contract prior to processing (including all gas where the lessee's arm's-length contract for the sale of that gas prior to processing provides for the value to be determined on the basis of a percentage of the purchaser's proceeds resulting from processing the gas). This section also applies to processed gas that must be valued prior to processing in accordance with § 206.155 of this part. Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, § 206.153 of this part shall apply instead of this section.

(2) The value of production, for royalty purposes, of gas subject to this subpart shall be the value of gas determined under this section less applicable allowances.

(b)(1)(i) The value of gas which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate. Also, where the lessee's arm's-length contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas, the value of production, for royalty purposes, shall never be less than a value equivalent to 100 percent of the value of the residue gas attributable to the processing of the lessee's gas.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then the MMS may require that the gas sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee

pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the gas production be valued pursuant to paragraph (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) The value of gas subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

(2) A value determined by consideration of other information relevant in valuing like-quality gas, including gross proceeds under arm's-length contracts for like-quality gas in the same field or nearby fields or areas, posted prices for gas, prices received in arm's-length spot sales of gas, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of the gas; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which gas may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed in paragraph (d)(1) of this section shall not apply to gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized MMS or State representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances.

(i) The lessee is required to place gas in marketable condition at no cost to the Federal Government unless otherwise provided in the lease agreement. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. § 552, or other Federal law. Any data specified by law

to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[53 FR 1272, Jan. 15, 1988, as amended at 56 FR 46530, Sept. 13, 1991; 61 FR 5464, Feb. 12, 1996]

§ 206.153 Valuation standards—processed gas.

(a)(1) This section applies to the valuation of all gas that is processed by the lessee and any other gas production to which this subpart applies and that is not subject to the valuation provisions of § 206.152 of this part. This section applies where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right.

(2) The value of production, for royalty purposes, of gas subject to this section shall be the combined value of the residue gas and all gas plant products determined pursuant to this section, plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 206.102 of this part, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(b)(1)(i) The value of the residue gas or any gas plant product which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit. For purposes of this section, residue gas or any gas plant product which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting these reviews and audits, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then the MMS may require that the residue gas or gas plant product sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the residue gas or gas plant product because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the residue gas or gas plant product be valued pursuant to paragraph (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of residue gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) The value of residue gas or any gas plant product which is not sold

pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality residue gas or gas plant products from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds under arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of such residue gas or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which any residue gas or gas plant products may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For the purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed by paragraph (d)(1) of this section shall not apply to residue gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines upon review or audit that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized MMS or State representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(3) A lessee shall notify MMS if it has determined any value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest computed on that difference pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(i) The lessee is required to place residue gas and gas plant products in marketable condition at no cost to the Federal Government unless otherwise provided in the lease agreement. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[53 FR 1272, Jan. 15, 1988, as amended at 56 FR 46530, Sept. 13, 1991; 61 FR 5465, Feb. 12, 1996]

§ 206.154 Determination of quantities and qualities for computing royalties.

(a)(1) Royalties shall be computed on the basis of the quantity and quality of unprocessed gas at the point of royalty settlement approved by BLM or MMS for onshore and OCS leases, respectively.

(2) If the value of gas determined pursuant to § 206.152 of this subpart is based upon a quantity and/or quality that is different from the quantity and/

or quality at the point of royalty settlement, as approved by BLM or MMS, that value shall be adjusted for the differences in quantity and/or quality.

(b)(1) For residue gas and gas plant products, the quantity basis for computing royalties due is the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(2) If the value of residue gas and/or gas plant products determined pursuant to § 206.153 of this subpart is based upon a quantity and/or quality of residue gas and/or gas plant products that is different from that which is attributable to a lease, determined in accordance with paragraph (c) of this section, that value shall be adjusted for the differences in quantity and/or quality.

(c) The quantity of the residue gas and gas plant products attributable to a lease shall be determined according to the following procedure:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which computations of royalty are based is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease shall be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of nonuniform content, the quantity of the residue gas allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of the residue gas by the arithmetic quotient obtained. The net output of gas plant products allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of each gas plant product by the arithmetic quotient obtained.

(4) A lessee may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, such method will be applicable to all gas production from Federal leases that is processed in the same plant.

(d)(1) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such loss is determined to have been unavoidable by BLM or MMS, as appropriate.

(2) Except as provided in paragraph (d)(1) of this section and 30 CFR 202.151(c), royalties are due on 100 percent of the volume determined in accordance with paragraphs (a) through (c) of this section. There can be no reduction in that determined volume for actual losses after the quantity basis has been determined or for theoretical losses that are claimed to have taken place. Royalties are due on 100 percent of the value of the unprocessed gas, residue gas, and/or gas plant products as provided in this subpart, less applicable allowances. There can be no deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after the quantity basis has been determined, or for theoretical losses that are claimed to have taken place.

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5465, Feb. 12, 1996]

§ 206.155 Accounting for comparison.

(a) Except as provided in paragraph (b) of this section, where the lessee (or a person to whom the lessee has transferred gas pursuant to a non-arm's-

length contract or without a contract) processes the lessee's gas and after processing the gas the residue gas is not sold pursuant to an arm's-length contract, the value, for royalty purposes, shall be the greater of (1) the combined value, for royalty purposes, of the residue gas and gas plant products resulting from processing the gas determined pursuant to § 206.153 of this subpart, plus the value, for royalty purposes, of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 206.102 of this subpart; or (2) the value, for royalty purposes, of the gas prior to processing determined in accordance with § 206.152 of this subpart.

(b) The requirement for accounting for comparison contained in the terms of leases will govern as provided in § 206.150(b) of this subpart. When accounting for comparison is required by the lease terms, such accounting for comparison shall be determined in accordance with paragraph (a) of this section.

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5465, Feb. 12, 1996]

§ 206.156 Transportation allowances—general.

(a) Where the value of gas has been determined pursuant to § 206.152 or § 206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

(b) Transportation costs must be allocated among all products produced and transported as provided in § 206.157.

(c)(1) Except as provided in paragraph (c)(3) of this section, for unprocessed gas valued in accordance with § 206.152 of this subpart, the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the unprocessed gas determined in accordance with § 206.152 of this subpart.

(2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with § 206.153 of this subpart the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the residue gas or gas plant product determined in accordance with § 206.153 of this subpart. For purposes of this section, natural gas liquids shall be considered one product.

(3) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (c)(2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances shall the value for royalty purposes under any selling arrangement be reduced to zero.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.54, or shall be entitled to a credit, without interest. If the lessee takes a deduction for transportation on the Form MMS–2014 by improperly netting the allowance against the sales value of the oil instead of reporting the allowance as a separate line item, he may be assessed an additional amount under 206.157(d).

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5465, Feb. 12, 1996]

§ 206.157 Determination of transportation allowances.

(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee under an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the unprocessed gas, residue

gas and/or gas plant products under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. Such allowances shall be subject to the provisions of paragraph (f) of this section. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014.

(ii) In conducting reviews and audits, MMS will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. MMS shall then determine the gas transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on the Form MMS–2014.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar per unit, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation

services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported shall be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, the lessee may not take an allowance for

transporting a product which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (b)(3)(i), the lessee may propose to the MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. MMS shall then determine the transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on the Form MMS–2014.

(5) A lessee may apply to the MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. The MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) (for both Federal and Indian leases) or a State regulatory agency (for Federal leases). The MMS shall deny the exception request if it determines that the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if: (i) No FERC or State regulatory agency cost analysis exists and the FERC or State regulatory agency, as applicable, has declined to investigate pursuant to MMS timely objections upon filing; and (ii) the tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS–2014.

(ii) The MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract.* (i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on the Form MMS–2014.

(ii) For new transportation facilities or arrangements, the lessee's initial deduction shall include estimates of the allowable gas transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(iv) If the lessee is authorized to use its FERC-approved or State regulatory agency-approved tariff as its transportation cost in accordance with paragraph (b)(5) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest and assessments.* (1) If a lessee nets a transportation allowance against the royalty value on the Form MMS–2014, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed $250 per lease selling arrangement per sales period.

(2) If a lessee deducts a transportation allowance on its Form MMS–2014 that exceeds 50 percent of the value of the gas transported without obtaining prior approval of MMS under § 206.156, the lessee shall pay interest on the excess allowance amount taken from the date such amount is taken to

the date the lessee files an exception request with MMS.

(3) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(4) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall be required to pay additional royalties due plus interest computed under 30 CFR 218.54 from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees transporting gas production from leases on the OCS, if the lessee's estimated transportation allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated transportation allowance is less than the allowance based on actual costs, the refund procedure will be specified by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts no cost shall be allowed for transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or state regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

[53 FR 1272, Jan. 15, 1988, as amended at 53 FR 45762, Nov. 14, 1988; 61 FR 5465, Feb. 12, 1996]

§ 206.158 Processing allowances—general.

(a) Where the value of gas is determined pursuant to § 206.153 of this subpart, a deduction shall be allowed for the reasonable actual costs of processing.

(b) Processing costs must be allocated among the gas plant products. A separate processing allowance must be determined for each gas plant product and processing plant relationship. Natural gas liquids (NGL's) shall be considered as one product.

(c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of the residue gas. Where there is no residue gas MMS may designate an appropriate gas plant product against which no allowance may be applied.

(2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product shall not exceed 66⅔ percent of the value of each gas plant product determined in accordance with § 206.153 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by § 206.156 of this subpart).

(3) Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value

for royalty purposes of any gas plant product be reduced to zero.

(d)(1) Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as ''sweetening,'' no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart. However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.

(2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

(ii) Prior MMS approval to continue an extraordinary processing cost allowance is not required. However, to retain the authority to deduct the allowance the lessee must report the deduction to MMS in a form and manner prescribed by MMS.

(e) If MMS determines that a lessee has improperly determined a processing allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest determined in accordance with 30 CFR 218.54, or shall be entitled to a credit, without interest. If the lessee takes a deduction for transportation on the Form MMS–2014 by improperly netting the allowance against the sales value of the oil instead of reporting the allowance as a separate line item, he may be assessed an additional amount under 206.159(d).

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5466, Feb. 12, 1996]

§ 206.159 Determination of processing allowances.

(a) *Arm's-length processing contracts.* (1)(i) For processing costs incurred by a lessee under an arm's-length contract, the processing allowance shall be the reasonable actual costs incurred by the lessee for processing the gas under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the processor for the processing. If the contract reflects more than the total consideration, then the MMS may require that the processing allowance be determined in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid pursuant to an arm's-length processing contract does not reflect the reasonable value of the processing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and lessor, then MMS shall require that the processing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the processing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's processing costs.

(2) If an arm's-length processing contract includes more than one gas plant

product and the processing costs attributable to each product can be determined from the contract, then the processing costs for each gas plant product shall be determined in accordance with the contract. No allowance may be taken for the costs of processing lease production which is not royalty-bearing.

(3) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use its proposed allocation procedure until MMS issues its determination. The lessee shall submit all relevant data to support its proposal. MMS shall then determine the processing allowance based upon the lessee's proposal and any additional information MMS deems necessary. No processing allowance will be granted for the costs of processing lease production which is not royalty bearing. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on Form MMS–2014.

(4) Where the lessee's payments for processing under an arm's-length contract are not based on a dollar per unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length processing contract or has no contract, including those situations where the lessee performs processing for itself, the processing allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All processing allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. The lessee must claim a processing allowance by reflecting it as a separate line entry on the Form MMS–2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual processing allowance.

(2) The processing allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for processing during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the processing plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the processing plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. When a lessee has elected to use either method for a processing plant, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the processing plant services, or a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a processing plant shall not alter the depreciation schedule established by the original processor/lessee for purposes of the allowance calculation. With or without a change in ownership, a processing plant shall be depreciated

only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable initial capital investment in the processing plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service after March 1, 1988.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) The processing allowance for each gas plant product shall be determined based on the lessee's reasonable and actual cost of processing the gas. Allocation of costs to each gas plant product shall be based upon generally accepted accounting principles. The lessee may not take an allowance for the costs of processing lease production which is not royalty bearing.

(4) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(3) of this section. The MMS may grant the exception only if: (i) The lessee has arm's-length contracts for processing other gas production at the same processing plant; and (ii) at least 50 percent of the gas processed annually at the plant is processed pursuant to arm's-length processing contracts; if the MMS grants the exception, the lessee shall use as its processing allowance the volume weighted average prices charged other persons pursuant to arm's-length contracts for processing at the same plant.

(c) *Reporting requirements*—(1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS–2014.

(ii) The MMS may require that a lessee submit arm's-length processing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2)*Non-arm's-length or no contract.* (i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on the Form MMS–2014.

(ii) For new processing plants, the lessee's initial deduction shall include estimates of the allowable gas processing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the plant or, if such data are not available, the lessee shall use estimates based upon industry data for similar gas processing plants.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(iv) If the lessee is authorized to use the volume weighted average prices charged other persons as its processing allowance in accordance with paragraph (b)(4) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest and assessments.* (1) If a lessee nets a processing allowance against the royalty value on the Form MMS–2014, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed $250 per lease selling arrangement per sales period.

(2) If a lessee deducts a processing allowance on its Form MMS–2014 that exceeds 66⅔ percent of the value of the gas processed without obtaining prior approval of MMS under § 206.158, the lessee shall pay interest on the excess allowance amount taken from the date such amount is taken to the date the lessee files an exception request with MMS.

(3) If a lessee erroneously reports a processing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(4) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual processing allowance is less than the amount the lessee has taken on Form

MMS–2014 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.54 from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual processing allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees processing gas production from leases on the OCS, if the lessee's estimated processing allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated costs were less than the actual costs, the refund procedure will be specified by MMS.

(f) *Other processing cost determinations.* The provisions of this section shall apply to determine processing costs when establishing value using a net back valuation procedure or any other procedure that requires deduction of processing costs.

[53 FR 1272, Jan. 15, 1988, as amended at 53 FR 45762, Nov. 14, 1988; 61 FR 5466, Feb. 12, 1996]

§ 206.106 Operating allowances.

Notwithstanding any other provisions in these regulations, an operating allowance may be used for the purpose of computing payment obligations when specified in the notice of sale and the lease. The allowance amount or formula shall be specified in the notice of sale and in the lease agreement.

[61 FR 3804, Feb. 2, 1996]

Subpart E—Indian Gas

SOURCE: 61 FR 5467, Feb. 12, 1996, unless otherwise noted.

§ 206.170 Purpose and scope.

(a) This subpart is applicable to all gas production from Indian (Tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma). The purpose of this subpart is to establish the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) If the specific provisions of any statute, treaty, or settlement agreement between the Indian lessor and a lessee resulting from administrative or judicial litigation, or oil and gas lease subject to the requirements of this subpart are inconsistent with any regulation in this subpart, then the lease, statute, treaty provision or settlement agreement shall govern to the extent of that inconsistency.

(c) All royalty payments made to any Tribe or allottee are subject to audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian oil and gas leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

§ 206.171 Definitions.

For purposes of this subpart:

Allowance means an approved or an (MMS)-initially accepted deduction in determining value for royalty purposes. Processing allowance means an allowance for the reasonable, actual costs incurred by the lessee for processing gas, or an approved or MMS-initially accepted deduction for costs of such processing, determined pursuant to this subpart. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving unprocessed gas, residue gas, or gas plant products to a point of sale or point of delivery off the lease, unit area, communitized area, or away from a processing plant, excluding gathering, or an approved or MMS-initially accepted deduction for costs of such transportation, determined pursuant to this subpart.

Area means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/

or gas lease products have similar quality, economic, and legal characteristics.

Arm's-length contract means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is pursuant to common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: ownership in excess of 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates. Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month, as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Indian leases.

BIA means the Bureau of Indian Affairs of the Department of the Interior.

BLM means the Bureau of Land Management of the Department of the Interior.

Compression means the process of raising the pressure of gas.

Condensate means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Field means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located.

Gas means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state pursuant to standard temperature and pressure conditions.

Gas plant products means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

Gathering means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM operations personnel for onshore leases.

Gross proceeds (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of unprocessed gas, residue gas, or gas plant products produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as compression, dehydration, measurement, and/or field gathering to the extent that the lessee is obligated to perform them at no cost to the Indian lessor, and payments for gas processing rights. Gross proceeds, as applied to gas, also includes but is not limited to reimbursements for severance taxes

and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Indian allottee means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States pursuant to a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context.

Lease products means any leased minerals attributable to, originating from, or allocated to Indian leases.

Lessee means any person to whom an Indian Tribe, or an Indian allottee issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

Like-quality lease products means lease products which have similar chemical, physical, and legal characteristics.

Marketable condition means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser pursuant to a sales contract typical for the field or area.

Marketing affiliate means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

Minimum royalty means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

MMS means the Minerals Management Service of the Department of the Interior.

Net-back method (or work-back method) means a method for calculating market value of gas at the lease. Pursuant to this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, or from the value of the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale pursuant to an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

Net output means the quantity of residue gas and each gas plant product that a processing plant produces.

Net profit share (for applicable Indian leases) means the specified share of the net profit from production of oil and gas as provided in the agreement.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Posted price means the price, net of all adjustments for quality and location, specified in publicly available price bulletins or other price notices available as part of normal business operations for quantities of unprocessed gas, residue gas, or gas plant products in marketable condition.

Processing means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/

or temperatures in a reservoir is not considered processing.

Residue gas means that hydrocarbon gas consisting principally of methane resulting from processing gas.

Selling arrangement means the individual contractual arrangements pursuant to which sales or dispositions of gas, residue gas and gas plant products are made. Selling arrangements are described by illustration in the MMS Royalty Management Program Oil and Gas Payor Handbook.

Spot sales agreement means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

Warranty contract means a long-term contract entered into prior to 1970, including any amendments thereto, for the sale of gas wherein the producer agrees to sell a specific amount of gas and the gas delivered in satisfaction of this obligation may come from fields or sources outside of the designated fields.

§ 206.172 Valuation standards—unprocessed gas.

(a)(1) This section applies to the valuation of all gas that is not processed and all gas that is processed but is sold or otherwise disposed of by the lessee pursuant to an arm's-length contract prior to processing (including all gas where the lessee's arm's-length contract for the sale of that gas prior to processing provides for the value to be determined on the basis of a percentage of the purchaser's proceeds resulting from processing the gas). This section also applies to processed gas that must be valued prior to processing in accordance with § 206.175 of this subpart. Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, § 206.173 of this subpart shall apply instead of this section.

(2) The value of production, for royalty purposes, of gas subject to this subpart shall be the value of gas determined pursuant to this section less applicable allowances determined pursuant to this subpart.

(3)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value of production for royalty purposes, if data are available to compute a major portion MMS will, where practicable, compare the value determined in accordance with this section with the major portion. The value to be used in determining the value of production for royalty purposes shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of gas production from the same field. The major portion will be calculated using like-quality gas sold pursuant to arm's-length contracts from the same field (or, if necessary to obtain a reasonable sample, from the same area) for each month. All such sales will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent (by volume) plus 1 mcf of the gas (starting from the bottom) is sold.

(b)(1)(i) The value of gas which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (b)(1)(iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate. Also, where the lessee's arm's-length contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas, the value of production, for royalty purposes, shall never be less than a value equivalent to 100 percent of the

value of the residue gas attributable to the processing of the lessee's gas.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then MMS may require that the gas sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the gas production be valued pursuant to paragraphs (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) The value of gas subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale pursuant to its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid pursuant to, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

(2) A value determined by consideration of other information relevant in valuing like-quality gas, including gross proceeds pursuant to arm's-length contracts for like-quality gas in the same field or nearby fields or areas, posted prices for gas, prices received in arm's-length spot sales of gas, other reliable public sources of price or market information, and other information as to the particular lease operation or the salability of the gas; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which gas may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed in paragraph (d)(1) of this section shall not apply to gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject

to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Indian lessee will make available upon request to the authorized MMS or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method pursuant to paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, pursuant to no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances determined pursuant to this subpart.

(i) The lessee is required to place gas in marketable condition at no cost to the Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims pursuant to its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed pursuant to its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value pursuant to this section shall be considered final or binding as against the Indian Tribes or allottees until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation, processing, or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made pursuant to this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from MMS or such lessor's lessee directly pursuant to the terms of the lease, 30 U.S.C. 1733, or other applicable law.

§ 206.173 Valuation standards—processed gas.

(a)(1) This section applies to the valuation of all gas that is processed by the lessee and any other gas production to which this subpart applies and that is not subject to the valuation provisions of § 206.172 of this part. This section applies where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right.

(2) The value of production, for royalty purposes, of gas subject to this section shall be the combined value of the residue gas and all gas plant products determined pursuant to this section, plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to section of this part, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(3)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value for royalty purposes, if data are available to compute a major portion MMS will, where practicable, compare the values determined in accordance with this section for any lease product with the major portion determined for that lease product. The value to be used in determining the value of production for royalty purposes shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of gas production from the same field, or for residue gas or gas plant products from the same processing plant, as applicable. The major portion will be calculated using like-quality lease products sold pursuant to arm's-length contracts from the same field or processing plant (or, if necessary to obtain a reasonable sample, from the same area or nearby processing plants) for each month. All such sales will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent (by volume) plus 1 mcf of the gas (starting from the bottom) is sold, or for gas plant products, 50 percent (by volume) plus 1 unit.

(b)(1)(i) The value of the residue gas or any gas plant product which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (b)(1)(iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit. For purposes of this section, residue gas or any gas plant product which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting these reviews and audits, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then MMS may require that the residue gas or gas plant product sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the residue gas or gas plant product because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the residue gas or gas plant product be valued pursuant to paragraphs (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of residue gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) The value of residue gas or any gas plant product which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale pursuant to its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid pursuant to, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality residue gas or gas plant products from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds pursuant to arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the salability of such residue gas or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which any residue gas or gas plant products may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For the purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed by paragraph (d)(1) of this section shall not apply to residue gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines upon review or audit that the reported value is inconsistent with the requirements of these regulations.

(2) The Indian lessee will make available upon request to the authorized MMS, or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(3) A lessee shall notify MMS if it has determined any value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method pursuant to paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest computed on that difference pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, pursuant to no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(i) The lessee is required to place residue gas and gas plant products in marketable condition at no cost to the Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims pursuant to its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application

for a price increase or benefit allowed pursuant to its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value pursuant to this section shall be considered final or binding against the Indian Tribes or allottees until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made pursuant to this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from MMS or such lessor's lessee directly pursuant to the terms of the lease, 30 U.S.C. 1733, or other applicable law.

§ 206.174 Determination of quantities and qualities for computing royalties.

(a)(1) Royalties shall be computed on the basis of the quantity and quality of unprocessed gas at the point of royalty settlement approved by BLM for onshore leases.

(2) If the value of gas determined pursuant to § 206.172 of this subpart is based upon a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement, as approved by BLM or MMS, that value shall be adjusted for the differences in quantity and/or quality.

(b)(1) For residue gas and gas plant products, the quantity basis for computing royalties due is the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(2) If the value of residue gas and/or gas plant products determined pursuant to § 206.173 of this subpart is based upon a quantity and/or quality of residue gas and/or gas plant products that is different from that which is attributable to a lease, determined in accordance with paragraph (c) of this section, that value shall be adjusted for the differences in quantity and/or quality.

(c) The quantity of the residue gas and gas plant products attributable to a lease shall be determined according to the following procedure:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which computations of royalty are based is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease shall be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of nonuniform content, the quantity of the residue gas allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to

the plant, and then multiplying the net output of the residue gas by the arithmetic quotient obtained. The net output of gas plant products allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of each gas plant product by the arithmetic quotient obtained.

(4) A lessee may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, such method will be applicable to all gas production from Indian leases that is processed in the same plant.

(d)(1) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such loss is determined to have been unavoidable by BLM .

(2) Except as provided in paragraph (d)(1) of this section and 30 CFR 202.171(c), royalties are due on 100 percent of the volume determined in accordance with paragraphs (a) through (c) of this section. There can be no reduction in that determined volume for actual losses after the quantity basis has been determined or for theoretical losses that are claimed to have taken place. Royalties are due on 100 percent of the value of the unprocessed gas, residue gas, and/or gas plant products as provided in this subpart, less applicable allowances. There can be no deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after the quantity basis has been determined, or for theoretical losses that are claimed to have taken place.

§ 206.175 Accounting for comparison.

(a) Except as provided in paragraph (b) of this section, where the lessee (or a person to whom the lessee has transferred gas pursuant to a non-arm's-length contract or without a contract) processes the lessee's gas and after processing the gas the residue gas is not sold pursuant to an arm's-length contract, the value, for royalty purposes, shall be the greater of (1) the combined value, for royalty purposes, of the residue gas and gas plant products resulting from processing the gas determined pursuant to § 206.173 of this subpart, plus the value, for royalty purposes, of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 206.52 of this subpart; or (2) the value, for royalty purposes, of the gas prior to processing determined in accordance with § 206.172 of this subpart.

(b) The requirement for accounting for comparison contained in the terms of leases, particularly Indian leases, will govern as provided in § 206.170(b) of this subpart. When accounting for comparison is required by the lease terms, such accounting for comparison shall be determined in accordance with paragraph (a) of this section.

§ 206.176 Transportation allowances—general.

(a) Where the value of gas has been determined pursuant to § 206.172 or § 206.173 of this subpart at a point (*e.g.*, sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

(b) Transportation costs must be allocated among all products produced and transported as provided in § 206.177.

(c)(1) Except as provided in paragraph (c)(3) of this section, for unprocessed gas valued in accordance with § 206.172 of this subpart, the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the unprocessed gas determined in accordance with § 206.172 of this subpart.

(2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with § 206.173 of this subpart the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the residue gas or gas plant product determined in accordance with § 206.173 of this subpart. For purposes of this section, natural gas liquids shall be considered one product.

(3) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (c)(2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation necessary for MMS to make a determination. Pursuant to no circumstances shall the value for royalty purposes pursuant to any selling arrangement be reduced to zero.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.54, or shall be entitled to a credit, without interest.

§ 206.177 Determination of transportation allowances.

(a) *Arm's-length transportation contracts.*(1)(i) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the unprocessed gas, residue gas and/or gas plant products pursuant to that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. Such allowances shall be subject to the provisions of paragraph (f) of this section. Before any deduction may be taken, the lessee must submit a completed page one of Form MMS–4295 (and Schedule 1), Gas Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4295 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(ii) In conducting reviews and audits, MMS will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be

taken for the costs of transporting lease production which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this subpart.

(3) If an arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988, or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS approves a longer period). MMS shall then determine the gas transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(4) Where the lessee's payments for transportation pursuant to an arm's-length contract are not based on a dollar per unit, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All transportation allowances deducted pursuant to a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. Before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS–4295 in accordance with paragraph (c)(2) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4295 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined pursuant to paragraph (c) of this section).

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported shall be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, the lessee may not take an allowance for transporting a product which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee begins the transportation, whichever is later, unless MMS approves a longer period. MMS shall then determine the transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(5) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of

this section. MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) for Indian leases. MMS shall deny the exception request if it determines that the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if: (i) No FERC cost analysis exists and the FERC has declined to investigate pursuant to MMS timely objections upon filing; and (ii) the tariff significantly exceeds the lessee's actual costs for transportation as determined pursuant to this section.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS–4295 (and Schedule 1) prior to, or at the same time as, the transportation allowance determined pursuant to an arm's-length contract is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4295 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received.

(ii) The initial Form MMS–4295 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS–4295 (and Schedule 1) within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v), (c)(2)(vii), and (c)(2)(viii) of this section, the lessee shall submit an initial Form MMS–4295 prior to, or at the same time as, the transportation allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4295 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received. The initial report may be based upon estimated costs.

(ii) The initial Form MMS–4295 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the transportation pursuant to the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS–4295 containing the actual costs for the previous reporting period. If the transportation is continuing, the lessee shall include on Form MMS–4295 its estimated costs for the next calendar year. The estimated transportation allowance shall be based on the actual costs for the previous reporting period plus or minus

any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form MMS–4295 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS–4295 shall include estimates of the allowable transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system, or if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no contract based transportation allowances which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS–4295. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If the lessee is authorized to use its FERC-approved tariff as its transportation cost in accordance with paragraph (b)(5) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) MMS may establish reporting dates for individual lessees different than those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on Form MMS–2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a processing allowance on its Form MMS–2014 without complying with the requirements of this section, the lessee shall pay interest only on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed pursuant to 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be entitled to a credit, without interest.

(2) For lessees transporting production from onshore Indian leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts no cost shall be allowed for transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or state regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

§ 206.178 Processing allowances—general.

(a) Where the value of gas is determined pursuant to § 206.173 of this subpart, a deduction shall be allowed for the reasonable actual costs of processing.

(b) Processing costs must be allocated among the gas plant products. A separate processing allowance must be determined for each gas plant product and processing plant relationship. Natural gas liquids (NGL's) shall be considered as one product.

(c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of the residue gas. Where there is no residue gas MMS may designate an appropriate gas plant product against which no allowance may be applied.

(2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product shall not exceed 66⅔ percent of the value of each gas plant product determined in accordance with § 206.173 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by § 206.176 of this subpart).

(3) Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS–4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.

(d)(1) Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as ''sweetening,'' no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart. However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.

(2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

(ii) Prior MMS approval to continue an extraordinary processing cost allowance is not required. However, to retain the authority to deduct the allowance the lessee must report the deduction to MMS in a form and manner prescribed by MMS.

(e) If MMS determines that a lessee has improperly determined a processing allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest determined in accordance with 30 CFR 218.54, or shall be entitled to a credit, without interest.

§ 206.179 Determination of processing allowances.

(a) *Arm's-length processing contracts.* (1)(i) For processing costs incurred by a lessee pursuant to an arm's-length contract, the processing allowance shall be the reasonable actual costs incurred by the lessee for processing the gas pursuant to that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. Before any deduction may be taken, the lessee must submit a completed page one of Form MMS–

4109, Gas Processing Allowance Summary Report, in accordance with paragraph (c)(1) of this section. A processing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4109 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the processor for the processing. If the contract reflects more than the total consideration, then MMS may require that the processing allowance be determined in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid pursuant to an arm's-length processing contract does not reflect the reasonable value of the processing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and lessor, then MMS shall require that the processing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the processing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's processing costs.

(2) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product can be determined from the contract, then the processing costs for each gas plant product shall be determined in accordance with the contract. No allowance may be taken for the costs of processing lease production which is not royalty-bearing.

(3) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use its proposed allocation procedure until MMS issues its determination. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee requests a processing allowance, whichever is later (unless MMS approves a longer period). MMS shall then determine the processing allowance based upon the lessee's proposal and any additional information MMS deems necessary. No processing allowance will be granted for the costs of processing lease production which is not royalty bearing.

(4) Where the lessee's payments for processing pursuant to an arm's-length contract are not based on a dollar per unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length processing contract or has no contract, including those situations where the lessee performs processing for itself, the processing allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All processing allowances deducted pursuant to a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. Before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS–4109 in accordance with paragraph (c)(2) of this section. A processing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4109 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. MMS will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its actual processing allowance.

(2) The processing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for processing during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on

undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the processing plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: maintenance of the processing plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. When a lessee has elected to use either method for a processing plant, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the processing plant services, or a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a processing plant shall not alter the depreciation schedule established by the original processor/lessee for purposes of the allowance calculation. With or without a change in ownership, a processing plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the allowable initial capital investment in the processing plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service after March 1, 1988.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent processing allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) The processing allowance for each gas plant product shall be determined based on the lessee's reasonable and actual cost of processing the gas. Allocation of costs to each gas plant product shall be based upon generally accepted accounting principles. The lessee may not take an allowance for the costs of processing lease production which is not royalty bearing.

(4) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(3) of this section. MMS may grant the exception only if: (i) The lessee has arm's-length contracts for processing other gas production at the same processing plant; and (ii) at least 50 percent of the gas processed annually at the plant is processed pursuant to arm's-length processing contracts; if MMS grants the exception, the lessee shall use as its processing allowance the volume weighted average prices charged other persons pursuant to arm's-length contracts for processing at the same plant.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) With the exception of those processing allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS–4109 (and Schedule 1) prior to the time, or

at the same time as, the processing allowance determined pursuant to an arm's-length contract is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4109 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received.

(ii) The initial Form MMS–4109 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a processing allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page 1 of Form MMS–4109 (and Schedule 1) within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) MMS may require that a lessee submit arm's-length processing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Processing allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purpose of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations became effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those processing allowances specified in paragraphs (c)(2)(v), (c)(2)(vii) and (c)(2)(viii) of this section, the lessee shall submit an initial Form MMS–4109 prior to, or at the same time as, the processing allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4109 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received. The initial report may be based upon estimated costs.

(ii) The initial Form MMS–4109 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a processing allowance and shall continue until the end of the calendar year, or until the processing pursuant to the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS–4109 containing the actual costs for the previous reporting period. If gas processing is continuing, the lessee shall include on Form MMS–4109 its estimated costs for the next calendar year. The estimated gas processing allowance shall be based on the actual costs for the previous period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form MMS–4109 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new processing plants, the lessee's initial Form MMS–4109 shall include estimates of the allowable gas processing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the plant, or if such data are not available, the lessee shall use estimates based upon industry data for similar gas processing plants.

(v) Processing allowances based on non-arm's-length or no contract situations which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate for gas production from Indian leases. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used by the lessee to prepare its Form MMS–4109. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If the lessee is authorized to use the volume weighted average prices charged other persons as its processing allowance in accordance with paragraph (b)(4) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) MMS may establish reporting dates for individual leases different from those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Processing allowances must be reported as a separate line on the Form MMS–2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a processing allowance on its Form MMS–2014 without complying with the requirements of this section, the lessee shall pay interest only on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a processing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual gas processing allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed pursuant to 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a processing allowance. If the actual processing allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance period, the lessee shall be entitled to a credit, without interest.

(2) For lessees processing production from onshore Indian leases, the lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other processing cost determinations.* The provisions of this section shall apply to determine processing costs when establishing value using a net back valuation procedure or any other procedure that requires deduction of processing costs.

Subpart F—Federal Coal

SOURCE: 54 FR 1523, Jan. 13, 1989, unless otherwise noted.

§ 206.250 Purpose and scope.

(a) This subpart is applicable to all coal produced from Federal coal leases. The purpose of this subpart is to establish the value of coal produced for royalty purposes, of all coal from Federal leases consistent with the mineral leasing laws, other applicable laws and lease terms.

(b) If the specific provisions of any statute or settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or any coal lease subject to the requirements of this subpart, are inconsistent with any regulation in this subpart then the statute, lease provision, or settlement shall govern to the extent of that inconsistency.

(c) All royalty payments made to the Mineral Management Service (MMS) are subject to later audit and adjustment.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5479, Feb. 12, 1996]

§ 206.251 Definitions.

Ad valorem lease means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

Allowance means a deduction used in determining value for royalty purposes. Coal washing allowance means an allowance for the reasonable, actual

costs incurred by the lessee for coal washing. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant.

Area means a geographic region in which coal has similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

Arm's-length contract means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(a) Ownership in excess of 50 percent constitutes control;

(b) Ownership of 10 through 50 percent creates a presumption of control; and

(c) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

BLM means the Bureau of Land Management of the Department of the Interior.

Coal means coal of all ranks from lignite through anthracite.

Coal washing means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Gross proceeds (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for a Federal coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

Lessee means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease

but who has assumed the royalty payment responsibility.

Like-quality coal means coal has similar chemical and physical characteristics.

Marketable condition means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

Mine means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

Net-back method means a method for calculating market value of coal at the lease or mine. Under this method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

Net output means the quantity of washed coal that a washing plant produces.

Netting is the deduction of an allowance from the sales value by reporting a one line net sales value, instead of correctly reporting the deduction as a separate line item on the Form MMS–2014.

Person means by individual, firm, corporation, association, partnership, consortium, or joint venture.

Selling arrangement means the individual contractual arrangements under which sales or dispositions of coal are made to a purchaser.

Spot market price means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

[54 FR 1523, Jan. 13, 1989, as amended at 55 FR 35433, Aug. 30, 1990; 61 FR 5479, Feb. 12, 1996]

§ 206.252 Information collection.

The information collection requirements contained in this subpart have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* The forms, filing date, and approved OMB clearance numbers are identified in 30 CFR 210.10 and 30 CFR 216.10.

§ 206.253 Coal subject to royalties—general provisions.

(a) All coal (except coal unavoidably lost as determined by BLM under 43 CFR part 3400) from a Federal lease subject to this part is subject to royalty. This includes coal used, sold, or otherwise disposed of by the lessee on or off the lease.

(b) If a lessee receives compensation for unavoidably lost coal through insurance coverage or other arrangements, royalties at the rate specified in the lease are to be paid on the amount of compensation received for the coal. No royalty is due on insurance compensation received by the lessee for other losses.

(c) If waste piles or slurry ponds are reworked to recover coal, the lessee shall pay royalty at the rate specified in the lease at the time the recovered coal is used, sold, or otherwise finally disposed of. The royalty rate shall be that rate applicable to the production method used to initially mine coal in the waste pile or slurry pond; i.e., underground mining method or surface mining method. Coal in waste pits or slurry ponds initially mined from Federal leases shall be allocated to such leases regardless of whether it is stored on Federal lands. The lessee shall maintain accurate records to determine to which individual Federal lease coal in the waste pit or slurry pond should be allocated. However, nothing in this section requires payment of a royalty on coal for which a royalty has already been paid.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5479, Feb. 12, 1996]

§ 206.254 Quality and quantity measurement standards for reporting and paying royalties.

(a) For leases subject to § 206.257 of this subpart, the quality of coal on which royalty is due shall be reported on the basis of percent sulfur, percent ash, and number of British thermal units (Btu) per pound of coal. Coal quality determinations shall be made at intervals prescribed in the lessee's sales contract. If there is no contract, or if the contract does not specify the

intervals of coal quality determination, the lessee shall propose a quality test schedule to MMS. In no case, however, shall quality tests be performed less than quarterly using standard industry-recognized testing methods. Coal quality information shall be reported on the appropriate forms required under 30 CFR part 216.

(b) For all leases subject to this subpart, the quantity of coal on which royalty is due shall be measured in short tons (of 2,000 pounds each) by methods prescribed by the BLM. Coal quantity information shall be reported on appropriate forms required under 30 CFR part 216 and on the Report of Sales and Royalty Remittance, Form MMS–2014, as required under 30 CFR part 210.

[54 FR 1523, Jan. 13, 1989, as amended at 57 FR 52720, Nov. 5, 1992]

§206.255 Point of royalty determination.

(a) For all leases subject to this subpart, royalty shall be computed on the basis of the quantity and quality of Federal coal in marketable condition measured at the point of royalty measurement as determined jointly by BLM and MMS.

(b) Coal produced and added to stockpiles or inventory does not require payment of royalty until such coal is later used, sold, or otherwise finally disposed of. MMS may ask BLM to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventory become excessive so as to increase the risk of degradation of the resource.

(c) The lessee shall pay royalty at a rate specified in the lease at the time the coal is used, sold, or otherwise finally disposed of, unless otherwise provided for at §206.256(d) of this subpart.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5480, Feb. 12, 1996]

§206.256 Valuation standards for cents-per-ton leases.

(a) This section is applicable to coal leases on Federal lands which provide for the determination of royalty on a cents-per-ton (or other quantity) basis.

(b) The royalty for coal from leases subject to this section shall be based on the dollar rate per ton prescribed in the lease. That dollar rate shall be applicable to the actual quantity of coal used, sold, or otherwise finally disposed of, including coal which is avoidably lost as determine by BLM pursuant to 43 CFR part 3400.

(c) For leases subject to this section, there shall be no allowances for transportation, removal of impurities, coal washing, or any other processing or preparation of the coal.

(d) When a coal lease is readjusted pursuant to 43 CFR part 3400 and the royalty valuation method changes from a cents-per-ton basis to an ad valorem basis, coal which is produced prior to the effective date of readjustment and sold or used within 30 days of the effective date of readjustment shall be valued pursuant to this section. All coal that is not used, sold, or otherwise finally disposed of within 30 days after the effective date of readjustment shall be valued pursuant to the provisions of §206.257 of this subpart, and royalties shall be paid at the royalty rate specified in the readjusted lease.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5480, Feb. 12, 1996]

§206.257 Valuation standards for ad valorem leases.

(a) This section is applicable to coal leases on Federal lands which provide for the determination of royalty as a percentage of the amount of value of coal (ad valorem). The value for royalty purposes of coal from such leases shall be the value of coal determined under this section, less applicable coal washing allowances and transportation allowances determined under §§206.258 through 206.262 of this subpart, or any allowance authorized by §206.265 of this subpart. The royalty due shall be equal to the value for royalty purposes multiplied by the royalty rate in the lease.

(b)(1) The value of coal that is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(2), (b)(3), and (b)(5) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the coal produced. If the contract does not reflect the total consideration, then the MMS may require that the coal sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be based on less than the gross proceeds accruing to the lessee for the coal production, including the additional consideration.

(3) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the coal production be valued pursuant to paragraph (c)(2) (ii), (iii), (iv), or (v) of this section, and in accordance with the notification requirements of paragraph (d)(3) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported coal value.

(4) The MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the coal production.

(5) The value of production for royalty purposes shall not include payments received by the lessee pursuant to a contract which the lessee demonstrates, to MMS's satisfaction, were not part of the total consideration paid for the purchase of coal production.

(c)(1) The value of coal from leases subject to this section and which is not sold pursuant to an arm's-length contract shall be determined in accordance with this section.

(2) If the value of the coal cannot be determined pursuant to paragraph (b) of this section, then the value shall be determined through application of other valuation criteria. The criteria shall be considered in the following order, and the value shall be based upon the first applicable criterion:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition of produced coal by other than an arm's-length contract), provided that those gross proceeds are within the range of the gross proceeds derived from, or paid under, comparable arm's-length contracts between buyers and sellers neither of whom is affiliated with the lessee for sales, purchases, or other dispositions of like-quality coal produced in the area. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Price, time of execution, duration, market or markets served, terms, quality of coal, quantity, and such other factors as may be appropriate to reflect the value of the coal;

(ii) Prices reported for that coal to a public utility commission;

(iii) Prices reported for that coal to the Energy Information Administration of the Department of Energy;

(iv) Other relevant matters including, but not limited to, published or publicly available spot market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain types of coal;

(v) If a reasonable value cannot be determined using paragraphs (c)(2) (i), (ii), (iii), or (iv) of this section, then a net-back method or any other reasonable method shall be used to determine value.

(3) When the value of coal is determined pursuant to paragraph (c)(2) of this section, that value determination shall be consistent with the provisions contained in paragraph (b)(5) of this section.

(d)(1) Where the value is determined pursuant to paragraph (c) of this section, that value does not require MMS's prior approval. However, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent

with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized MMS or State representatives, to the Inspector General of the Department of the Interior or other persons authorized to receive such information, arm's-length sales value and sales quantity data for like-quality coal sold, purchased, or otherwise obtained by the lessee from the area.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraphs (c)(2) (ii), (iii), (iv), or (v) of this section. The notification shall be by letter to the Associate Director for Royalty Management of his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this section is a one-time notification due no later than the month the lessee first reports royalties on the Form MMS–2014 using a valuation method authorized by paragraphs (c)(2) (ii), (iii), (iv), or (v) of this section, and each time there is a change in a method under paragraphs (c)(2) (iv) or (v) of this section.

(e) If MMS determines that a lessee has not properly determined value, the lessee shall be liable for the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also be liable for interest computed pursuant to 30 CFR 218.202. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of this section, under no circumstances shall the value for royalty purposes be less than the gross proceeds accruing to the lessee for the disposition of produced coal less applicable provisions of paragraph (b)(5) of this section and less applicable allowances determined pursuant to §§ 206.258 through 206.262 and § 206.265 of this subpart.

(h) The lessee is required to place coal in marketable condition at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds has been reduced because the purchaser, or any other person, is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the coal in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract, and may be retroactively applied to value for royalty purposes for a period not to exceed two years, unless MMS approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of coal.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or

other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) Certain information submitted to MMS to support valuation proposals, including transportation, coal washing, or other allowances under § 206.265 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 522. Any data specified by the Act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[54 FR 1523, Jan. 13, 1989, as amended at 55 FR 35433, Aug. 30, 1990; 57 FR 52720, Nov. 5, 1992; 61 FR 5480, Feb. 12, 1996]

§ 206.258 Washing allowances—general.

(a) For ad valorem leases subject to § 206.257 of this subpart, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to wash coal, unless the value determined pursuant to § 206.257 of this subpart was based upon like-quality unwashed coal. Under no circumstances shall the washing allowance and the transportation allowance authorized by § 206.262 of this subpart reduce the value for royalty purposes to zero.

(b) If MMS determines that a lessee has improperly determined a washing allowance authorized by this section, then the lessee shall be liable for any additional royalties, plus interest determined in accordance with 30 CFR 218.202, or shall be entitled to a credit without interest.

(c) Lessees shall not disproportionately allocate washing costs to Federal leases.

(d) No cost normally associated with mining operations and which are necessary for placing coal in marketable condition shall be allowed as a cost of washing.

(e) Coal washing costs shall only be recognized as allowances when the washed coal is sold and royalties are reported and paid.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5480, Feb. 12, 1996]

§ 206.259 Determination of washing allowances.

(a) *Arm's-length contracts.*— (1) For washing costs incurred by a lessee under an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a washing allowance by reporting it as a separate line entry on the Form MMS–2014.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then the MMS may require that the washing allowance be determined in accordance with paragraph (b) of this section.

(3) If the MMS determines that the consideration paid pursuant to an arm's-length washing contract does not reflect the reasonable value of the washing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the washing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the washing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's washing costs.

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit

basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

(b) *Non-arm's-length or no contract.*—(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a washing allowance by reporting it as a separate line entry on the Form MMS–2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual washing allowance.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the wash plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes, rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the wash plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and severance taxes, including royalities, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (B) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a wash plant shall not alter the depreciation schedule established by the original operator/lessee for purposes of the allowance calculation. With or without a change in ownership, a wash plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable capital investment in the wash plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) *Reporting requirements*—(1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS–2014.

(ii) The MMS may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract.* (i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on the Form MMS–2014.

(ii) For new washing facilities or arrangements, the lessee's initial washing deduction shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the processing system or, if such data are not available, the lessee shall use estimates based upon industry data for similar washing systems.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(d) *Interest and assessments.* (1) If a lessee nets a washing allowance on the Form MMS–2014, then the lessee shall be assessed an amount up to 10 percent of the allowance netted not to exceed $250 per lease selling arrangement per sales period.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments.* (1) If the actual coal washing allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.202 from the date when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual washing allowance is greater than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other washing cost determinations.* The provisions of this section shall apply to determine washing costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of washing costs.

[54 FR 1523, Jan. 13, 1989, as amended at 57 FR 52720, Nov. 5, 1992; 61 FR 5480, Feb. 12, 1996]

§ 206.260 Allocation of washed coal.

(a) When coal is subjected to washing, the washed coal must be allocated to the leases from which it was extracted.

(b) When the net output of coal from a washing plant is derived from coal obtained from only one lease, the quantity of washed coal allocable to the lease will be based on the net output of the washing plant.

(c) When the net output of coal from a washing plant is derived from coal obtained from more than one lease, unless determined otherwise by BLM, the quantity of net output of washed coal allocable to each lease will be based on the ratio of measured quantities of coal delivered to the washing plant and washed from each lease compared to the total measured quantities of coal delivered to the washing plant and washed.

§ 206.261 Transportation allowances—general.

(a) For ad valorem leases subject to § 206.257 of this subpart, where the value for royalty purposes has been determined at a point remote from the lease or mine, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to:

(1) Transport the coal from a Federal lease to a sales point which is remote from both the lease and mine; or

(2) Transport the coal from a Federal lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point. In-mine transportation costs shall not be included in the transportation allowance.

(b) Under no circumstances shall the washing allowance and the transportation allowance authorized by § 206.257 of this subpart reduce the value of coal under any selling arrangement to zero.

(c)(1) When coal transported from a mine to a wash plant is eligible for a transportation allowance in accordance with this section, the lessee is not required to allocate transportation costs between the quantity of clean coal output and the rejected waste material. The transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of cleaned coal transported.

(2) For coal that is not washed at a wash plant, the transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of coal transported.

(3) Transportation costs shall only be recognized as allowances when the transported coal is sold and royalties are reported and paid.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this section, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.202, or shall be entitled to a credit, without interest.

(e) Lessees shall not disproportionately allocate transportation costs to Federal leases.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5481, Feb. 12, 1996]

§ 206.262 Determination of transportation allowances.

(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract*—(1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS–2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's

actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or paragraph (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(B)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) A lessee may apply to MMS for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (b)(2) of this section. MMS will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency or by a State regulatory agency (for Federal leases). MMS shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if:

(i) No Federal or State regulatory agency costs analysis exists and the Federal or State regulatory agency, as applicable, has declined to investigate under MMS timely objections upon filing; and

(ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements*— (1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS–2014.

(ii) The MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract*—(i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on Form MMS–2014.

(ii) For new transportation facilities or arrangements, the lessee's initial deduction shall include estimates of the allowable coal transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(iv) [Reserved]

(v) If the lessee is authorized to use its Federal- or State-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest and assessments.* (1) If a lessee nets a transportation allowance on Form MMS–2014, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed $250 per lease selling arrangement per sales period.

(e) *Adjustments.* (1) If the actual coal transportation allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.202 from the date when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual transportation allowance is greater than amount the lessee has taken on Form MMS–2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) [Reserved]

(f) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

[54 FR 1523, Jan. 13, 1989, as amended at 57 FR 41864, Sept. 14, 1992; 57 FR 52720, Nov. 5, 1992; 61 FR 5481, Feb. 12, 1996]

§ 206.263 Contract submission.

(a) The lessee and other payors shall submit to MMS, upon request, contracts for the sale of coal from ad valorem leases subject to this subpart. The MMS must receive the contracts within a reasonable period of time, as specified by MMS. Lessees shall include as part of the submittal requirements any contracts, agreements, contract amendments, or other documents that affect the gross proceeds received for the sale of coal, as well as any other information regarding any consideration received for the sale or disposition of coal that is not included in such contracts. At the time of its contract submittals, MMS may require the lessee to certify in writing that it has provided all documents and information that reflect the total consideration provided by purchasers of coal from ad valorem leases subject to this subpart. Information requested under this section may include contracts for both ad valorem and cents-per-ton leases and shall be available in the lessee's offices during normal business hours or provided to MMS at such time and in such manner as may be requested by authorized Department of the Interior personnel. Any oral sales arrangement negotiated by the lessee must be placed in a written form and be retained by the lessee. Nothing in this section shall be construed to limit the authority of MMS to obtain or have access to information pursuant to 30 CFR part 212.

(b) Lessees and other payors shall designate, for each contract submitted pursuant to this section, whether the contract in arm's-length or non-arm's-length.

(c) A lessee's or other payor's determination that its contract is arm's-length is subject to future audit to verify that the contract meets the criteria

of the arm's-length contract definition in § 206.251 of this subpart.

(d) Information required to be submitted under this section that constitutes trade secrets and commercial and financial information that is identified as privileged or confidential shall not be available for public inspection or made public or disclosed without the consent of the lessee or other payor, except as otherwise provided by law or regulation.

§ 206.264 In-situ and surface gasification and liquefaction operations.

In an ad valorem Federal coal lease is developed by in-situ or surface gasification or liquefaction technology, the lessee shall propose the value of coal for royalty purposes to MMS. The MMS will review the lessee's proposal and issue a value determination. The lessee may use its proposed value until MMS issues a value determination.

§ 206.265 Value enhancement of marketable coal.

If, prior to use, sale, or other disposition, the lessee enhances the value of coal after the coal has been placed in marketable condition in accordance with § 206.257(h) of this subpart, the lessee shall notify MMS that such processing is occurring or will occur. The value of that production shall be determined as follows:

(a) A value established for the feedstock coal in marketable condition by application of the provisions of § 206.257(c)(2)(i-iv) of this subpart; or,

(b) In the event that a value cannot be established in accordance with subsection (a), then the value of production will be determined in accordance with § 206.257(c)(2)(v) of this subpart and the value shall be the lessee's gross proceeds accruing from the disposition of the enhanced product, reduced by MMS-approved processing costs and procedures including a rate of return on investment equal to two times the Standard and Poor's BBB bond rate applicable under § 206.259(b)(2)(v) of this subpart.

Subpart G—Other Solid Minerals

§ 206.301 Value basis for royalty computation.

(a) The gross value for royalty purposes shall be the sale or contract unit price times the number of units sold, *Provided, however,* That where the authorized officer determines:

(1) That a contract of sale or other business arrangement between the lessee and a purchaser of some or all of the commodities produced from the lease is not a bona fide transaction between independent parties because it is based in whole or in part upon considerations other than the value of the commodities, or (2) That no bona fide sales price is received for some or all of such commodities because the lessee is consuming them, the authorized officer shall determine their gross value, taking into account: (i) All prices received by the lessee in all bona fide transactions, (ii) Prices paid for commodities of like quality produced from the same general area, and (iii) Such other relevant factors as the authorized officer may deem appropriate; and *Provided further,* That in a situation where an estimated value is used, the authorized officer shall require the payment of such additional royalties, or allow such credits or refunds as may be necessary to adjust royalty payment to reflect the actual gross value.

(b) The lessee is required to certify that the values reported for royalty purposes are bona fide sales not involving considerations other than the sale of the mineral, and he may be required by the authorized officer to supply supporting information.

[43 FR 10341, Mar. 13, 1978. Redesignated at 48 FR 36588, Aug. 12, 1983, and amended at 48 FR 44795, Sept. 30, 1983. Further redesignated at 51 FR 15212, Apr. 22, 1986. Redesignated at 53 FR 39461, Oct. 7, 1988]

Subpart H—Geothermal Resources

SOURCE: 56 FR 57276, Nov. 8, 1991, unless otherwise noted.

§ 206.350 Purpose and scope.

(a) This subpart is applicable to all geothermal resources produced from Federal geothermal leases issued pursuant to the Geothermal Steam Act of 1970, as amended (30 U.S.C. 1001 *et seq.*). The purpose of this subpart is to establish the value of geothermal production for royalty purposes.

(b) All royalty payments made to MMS are subject to audit and adjustment.

§ 206.351 Definitions.

For purposes of this subpart:

Arm's-length contract means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with, another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(1) Ownership in excess of 50 percent constitutes control;

(2) Ownership of 10 through 50 percent creates a rebuttable presumption of control; and

(3) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The MMS may require the lessee to certify the claimed nature of ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for the production month as well as when the contract was executed.

Audit means a procedure having the same meaning and effect as that described at 30 CFR part 217 for verifying royalty payment compliance activities of lessees or other authorized persons who pay royalties, rents, or bonuses on Federal geothermal leases.

Byproduct means:

(1) Any mineral or minerals (exclusive of oil, hydrocarbon gas, and helium) which are found in solution or developed in association with geothermal fluids and which have a value of less than 75 per centum of the value of the geothermal energy or are not, because of quantity, quality, or technical difficulties in extraction and production, of sufficient value to warrant extraction and production by themselves, and

(2) Commercially demineralized water.

Byproduct recovery facility means the facility or facilities at which byproducts are placed in marketable condition.

Byproduct transportation allowance means an approved allowance for the lessee's reasonable, actual costs, excluding gathering, incurred for moving byproducts, including commercially demineralized water, to a point of sale or point of delivery off the lease, unit area, or communitized area.

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Deduction means a subtraction used in the geothermal netback procedure for determining the value of geothermal resources utilized by the lessee to generate electricity. *Transmission deduction* means a deduction for the lessee's reasonable actual costs incurred to wheel or transmit the electricity from the lessee's powerplant to the purchaser's delivery point. *Generating deduction* means a deduction for the lessee's reasonable, actual costs of generating plant tailgate electricity.

Delivered electricity means the amount of electricity in kilowatthours delivered to the purchaser.

Direct utilization means any process other than electrical generation in which the thermal energy of the geothermal resource is utilized, including, but not limited to, space heating, greenhouse operations, and industrial or agricultural process heat.

Field means the land surface vertically projected over a subsurface geothermal reservoir encompassing at least the outermost boundaries of all

geothermal accumulations known to be within that reservoir. Geothermal fields are usually given names and their official boundaries are often designated by regulatory agencies in the respective States in which the fields are located.

Gathering means the efficient movement of lease production from the wellhead to the point of utilization.

Geothermal netback procedure means the method of determining the value of geothermal resources that are utilized in a lessee-owned powerplant for the generation and sale of electricity by deducting the lessee's reasonable, actual transmission and generating costs from the sales price or value of the electricity to derive the value of the geothermal resource at the powerplant inlet.

Geothermal resources means:

(1) All products of geothermal processes, including indigenous steam, hot water, and hot brines;

(2) Steam and other gases, hot water, and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(3) Heat or other associated energy found in geothermal formations; and

(4) Any byproducts.

Geothermal utilization facility means a powerplant or direct utilization facility that utilizes the heat or other energy of the geothermal resource.

Gross proceeds (for royalty purposes) means the total monies and other consideration accruing to a geothermal lessee for any disposition of geothermal resources, including total payments for the sale of electricity generated by the lessee from lease-produced geothermal resources. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as effluent injection, field operation and maintenance, drilling or workover of wells, and/or field gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds also includes, but is not limited to, reimbursements for production taxes and other taxes. Tax reimbursements are part of gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Lease means a geothermal lease issued under authority of the Geothermal Steam Act of 1970, as amended (30 U.S.C. 1001 *et seq.*), unless the context indicates otherwise.

Lessee means any person to whom the United States issues a geothermal lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a geothermal lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility. This also includes any affiliate of the lessee that utilizes the geothermal resource to generate electricity, in a direct utilization process, or to recover byproducts, or any affiliate that transports lease production.

Like-quality lease products means lease products that have similar chemical, physical, and legal characteristics.

Marketable condition means lease products that are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field.

Minimum royalty means the minimum amount of annual royalty as specified in the lease or in applicable leasing regulations that the lessee must pay after commencement of geothermal production in commercial quantities.

No sales means the utilization or disposal of geothermal resources without the benefit of a sale.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

Plant tailgate electricity means the amount of electricity in kilowatthours generated by the powerplant exclusive of plant parasitic electricity, but inclusive of any electricity generated by the powerplant and returned to the lease for lease operations. Plant tailgate electricity should be measured at, or calculated for, the high voltage side of

the transformer in the plant switchyard.

Point of utilization means the powerplant or direct utilization facility in which the geothermal resource (steam or hot water) is utilized.

Reasonable alternative fuel means a conventional fuel (such as coal, oil, gas, or wood) that would normally be used as a source of heat in direct utilization operations.

Secretary means the Secretary of the Department of the Interior or any person duly authorized to exercise the powers vested in that office.

Selling arrangement means the individually contracted arrangements under which sales or dispositions of geothermal resources are made, including sales or dispositions of byproducts and electricity sales where the lessee generates electricity from lease geothermal production.

Spot market price means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding 1 year.

Wheeling means the transmission of electricity from a powerplant to the point of delivery.

§ 206.352 Valuation standards for electrical generation.

(a) The value of geothermal resources produced from leases subject to this subpart and used to generate electricity shall be determined pursuant to this section.

(b)(1)(i) The value of geothermal resources that are sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (b)(1)(iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to the seller for the geothermal resource. If the contract does not reflect the total consideration, MMS may require that the geothermal resource sold pursuant to that contract be valued in accordance with paragraph (d) of this section. Value shall not be less than the gross proceeds accruing to the lessee, including any additional consideration received.

(iii) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, MMS shall require the geothermal resource to be valued pursuant to paragraph (d) of this section, and notification provided to MMS in accordance with paragraph (e)(3) of this section. If MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) The MMS may require a lessee to certify that the provisions in its arm's-length contract include all of the consideration to be paid by the buyer, either directly or indirectly, for the geothermal resource.

(c)(1) The value of geothermal resources subject to this section that are sold under a non-arm's-length contract shall be determined in accordance with the first applicable of the following paragraphs:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract provided that those gross proceeds are not less than the gross proceeds derived from or paid under the lowest-priced available comparable arm's-length contract for sales of geothermal resources to the lessee-affiliate's same powerplant (the ''minimum value''). If the gross proceeds under the lessee's non-arm's-length contract are less than the ''minimum value'' under available comparable arm's-length contracts, or if there are no available comparable arm's-length contracts, value will be determined by the weighted average of the gross proceeds established under arm's-length contracts for the sale of significant quantities of geothermal resources to

the same powerplant. Available contracts will mean contracts in the possession of the lessee, the lessee's affiliate, or MMS. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Time of execution, duration, terms, quality of the geothermal resource, volume, dedication to the same powerplant, and other factors that may be appropriate to reflect the value of the resource;

(ii) The value determined by the geothermal netback procedure. Under the geothermal netback procedure, the lessee's reasonable actual costs for the generation and transmission of electricity shall be deducted from the lessee's gross proceeds received for the sale of electricity to determine the value of the geothermal resource. Transmission deductions shall be determined pursuant to § 206.353 of this part. Generating deductions shall be determined pursuant to § 206.354 of this part; or

(iii) A value determined by any other reasonable valuation method approved by MMS.

(2) Value determinations made pursuant to this paragraph are subject to the notification requirements of paragraph (e) of this section.

(d)(1) The value of geothermal resources subject to this section that are not subject to a sales transaction (''no sales'' geothermal resources) but are instead utilized directly by the lessee in its own powerplant for the generation and sale of electricity shall be determined in accordance with the first applicable of the following paragraphs:

(i) The weighted average of the gross proceeds established in arm's-length contracts for the purchase of significant quantities of geothermal resources to operate the lessee's same powerplant. In evaluating the acceptability of arm's-length contracts, the following factors shall be considered: Time of execution, duration, terms, volume, quality of resource, and such other factors as may be appropriate to reflect the value of the resource;

(ii) The value determined by the geothermal netback procedure. Under the geothermal netback procedure, the lessee's reasonable actual costs for the generation and transmission of electricity shall be deducted from the lessee's gross proceeds received for the sale of electricity to determine the value of the geothermal resource. Transmission deductions shall be determined pursuant to § 206.353 of this part. Generating deductions shall be determined pursuant to § 206.354 of this part; or

(iii) A value determined by any other reasonable valuation method approved by MMS.

(2) Value determinations made pursuant to this paragraph are subject to the notification requirements of paragraph (e) of this section.

(e)(1) Pursuant to subpart H of 30 CFR part 212, the lessee shall retain all data relevant to the determination of royalty value, particularly where the value is determined pursuant to paragraph (c) or (d) of this section. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Upon request, lessees shall make available to authorized MMS representatives or to other authorized persons any and all contracts for the sale or other disposition of the lease production; contracts for the sale, generation, and/or transmission of electricity attributable to lease production; and any arm's-length sales and other data for like-quality production sold, purchased, or otherwise obtained by the lessee from the field as may be necessary to support a value determination.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c) or (d) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c) or (d) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.302. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method and may use that method in determining value, for royalty purposes, until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria consistent with this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee where geothermal resources are directly sold.

(i) The lessee is required to place geothermal resources in marketable condition and to deliver geothermal resources to the powerplant at no cost to the Federal lessor. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the geothermal resource in marketable condition or deliver it to the powerplant.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to the contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of geothermal resources.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support value determinations is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulations of the Department, 43 CFR part 2.

§ 206.353 Determination of transmission deductions.

(a) Where the value of geothermal energy is determined by the geothermal netback procedure pursuant to paragraphs (c)(1)(ii) and (d)(1)(ii) of § 206.352 of this subpart, a transmission deduction shall be subtracted from the lessee's gross proceeds received for the sale of electricity to determine the plant tailgate value of the electricity.

The transmission deduction consists of either or both of two components:

(1) Transmission line costs as determined pursuant to paragraph (b) of this section, and

(2) Wheeling costs if the electricity is transmitted across a third-party's transmission line under an arm's-length wheeling agreement. Transmission deductions are subject to the limitation prescribed in paragraph (c) of this section.

(b)(1) Transmission-line costs shall be based on the lessee's actual costs associated with the construction and operation of a transmission line for the purpose of transmitting electricity attributable and allocable to the lessee's powerplant utilizing Federal geothermal resources. The monthly transmission line cost component of the transmission deduction is determined by multiplying the annual transmission line cost rate (in dollars per kilowatthour) by the amount of electricity delivered for the reporting month. The transmission line cost rate shall be redetermined annually at the beginning of the same month of the year in which the transmission line was placed into service, the same month of the year in which the powerplant was placed into service, or, at the lessee's option, at a time concurrent with the beginning of the lessee's annual corporate accounting period; *Provided,* however, the period selected must coincide with the same period chosen for the generating deduction pursuant to § 206.354(b)(1). After a deduction period is chosen, the lessee may not later elect to use a different deduction period without MMS approval.

(2) Allowable transmission-line costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the capital investment in the transmission line multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable assets, including costs of delivery and installation of capital equipment, that are an integral part of the transmission line. A return on capital invested in the purchase of real estate for transmission facilities may be allowed provided that the lessee demonstrates the necessity for such purchase, the purchased land is not on a Federal geothermal lease, and MMS approves the deduction; the rate of return shall be the same rate determined in paragraph (b)(2)(v) of this section.

(i) Allowable operating expenses include operations supervision and engineering, operations labor, materials, ad valorem property taxes, rent, supplies, and any other directly allocable and attributable operating expenses that the lessee can document.

(ii) Allowable maintenance expenses include maintenance of the transmission line, maintenance of equipment, maintenance labor, and other directly allocable and attributable maintenance expenses that the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transmission line is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) To compute costs associated with capital investment, a lessee may use either depreciation with a return on undepreciated capital investment, or a return on capital investment. After a lessee has elected to use either method, the lessee may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, the lessee must use a straight-line depreciation method based on the expected life of the geothermal project, usually the term of the electricity sales contract or other depreciation period acceptable to MMS. A change in ownership of a transmission line shall not alter the depreciation schedule established by the original lessee-owner for purposes of computing transmission line costs. With or without a change in ownership, a transmission line shall be depreciated only once. The rate of return used to compute the return on undepreciated capital investment shall be determined pursuant to paragraph (b)(2)(v) of this section.

(B) To compute a return on capital investment, the allowed cost shall be the amount equal to the allowable capital investment in the transmission line multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transmission lines first placed into service on or after March 1, 1988.

(v) The rate of return shall be 2 times Standard and Poor's industrial BBB bond rate. The rate of return shall be 2 times the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the annual deduction period and shall be effective during the following deduction period. The rate shall be redetermined annually at the beginning of the same month beginning the annual deduction period chosen pursuant to paragraph (b)(1) of this section.

(3) Transmission-line cost rates, determined annually, are computed by dividing the sum of the operating, maintenance, overhead, and capital costs by the annual amount of delivered electricity.

(4) For new transmission lines, the lessee's costs for the first deduction period shall be based on estimated expenses (including overhead) for operating and maintaining the transmission line. For subsequent deduction periods, the transmission line costs shall be estimated based on the lessee's actual operating and maintenance expenses for the previous period adjusted for decreases or increases that the lessee knows will affect the deduction in the current period.

(c) Under no circumstances shall the transmission deduction plus the generating deduction determined pursuant to § 206.354 of this subpart reduce the royalty value of the geothermal resource to zero.

(d)(1) If the actual transmission deduction determined at the end of the annual reporting period is less than the amount the lessee estimated and used in the netback procedure during the reporting period, the lessee shall be required to pay additional royalties retroactive to the first month of the reporting period, plus interest computed pursuant to 30 CFR 218.302. If the actual transmission deduction is greater than the amount applied in the netback calculation, the lessee shall be entitled to a credit.

(2) Lessees must submit corrected Forms MMS–2014 to reflect adjustments to royalty payments in accordance with MMS instructions.

(e)(1) All transmission deductions are subject to review, audit, and adjustment. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transmission deduction and adjust royalty values accordingly.

(2) Pursuant to subpart H of 30 CFR part 212, the lessee must maintain all data and records supporting its transmission deduction, including wheeling and other transmission-related agreements. These data and records must be made available to MMS and other authorized personnel upon request, and shall be maintained in a confidential manner in accordance with applicable laws and regulations pursuant to § 206.352 of this subpart.

(f) A one-time refund of royalties equal to the royalty amount of actual dismantlement costs attributable to the transmission line that are in excess of actual income attributable to the salvage of the transmission line will be allowed at the completion of the dismantlement and salvage operations.

§ 206.354 Determination of generating deductions.

(a) Where the value of geothermal energy is determined by the geothermal netback procedure pursuant to paragraphs (c)(1)(ii) and (d)(1)(ii) of § 206.352 of this subpart, that value shall be determined by deducting the lessee's reasonable actual costs incurred to generate electricity from the plant tailgate value of the electricity (usually the transmission-reduced value of the delivered electricity). Generating deductions are subject to the limitation prescribed in paragraph (c) of this section.

(b)(1) Generating costs shall be based on the lessee's actual annual costs associated with the construction and operation of a geothermal powerplant. The monthly generating deduction is determined by multiplying the annual generating cost rate (in dollars per

kilowatthour) by the amount of plant tailgate electricity measured (or computed) for the reporting month. The generating cost rate is determined from the annual amount of plant tailgate electricity and must be redetermined annually at the beginning of the same month of the year in which the powerplant was placed into service or, at the lessee's option, at a time concurrent with the beginning of the lessee's annual corporate accounting period; *Provided,* however, the period selected must coincide with the same period chosen for the transmission deduction pursuant to § 206.353(b)(1). After a deduction period is chosen, the lessee may not later elect to use a different deduction period without MMS approval.

(2) Allowable generating costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the capital investment in the powerplant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable assets, including costs of delivery and installation of capital equipment, that are an integral part of the powerplant or are required by the design specifications of the power conversion cycle. A return on capital invested in the purchase of real estate for a powerplant site may be allowed provided that the lessee demonstrates the necessity for such purchase, the purchased land is not on a Federal geothermal lease, and MMS approves the deduction; the rate of return shall be the same rate determined in paragraph (b)(2)(v) of this section. The costs of gathering systems and other production-related facilities are not allowed.

(i) Allowable operating expenses include operations supervision and engineering, operations labor, materials, ad valorem property taxes, rent, supplies, auxiliary fuel and/or utilities used to operate the powerplant during down time, and any other directly allocable and attributable operating expense that the lessee can document.

(ii) Allowable maintenance expenses include maintenance of the powerplant, maintenance of equipment, maintenance labor, and other directly allocable and attributable maintenance expenses that the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the powerplant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) To compute costs associated with capital investment, a lessee may use either depreciation with a return on undepreciated capital investment, or a return on capital investment. After a lessee has elected to use either method, the lessee may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, the lessee must use a straight-line depreciation method based on the life of the geothermal project, usually the term of the electricity sales contract or other depreciation period acceptable to MMS. A change in ownership of a powerplant shall not alter the depreciation schedule established by the original lessee-owner for computing the generating costs. With or without a change in ownership, a powerplant shall be depreciated only once. The rate of return used to compute the return on undepreciated capital investment shall be determined pursuant to paragraph (b)(2)(v) of this section.

(B) To compute a return on capital investment, the allowed cost shall be the amount equal to the allowable capital investment in the powerplant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to powerplants first placed into service on or after March 1, 1988.

(v) The rate of return shall be 2 times Standard and Poor's industrial BBB bond rate. The rate of return shall be 2 times the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the annual deduction period and shall be effective during the following deduction period.

The rate shall be redetermined annually at the beginning of the same month beginning the annual deduction period chosen pursuant to paragraph (b)(1) of this section.

(3) Generating cost rates, determined annually, shall be computed by dividing the sum of the operating, maintenance, overhead, and capital costs by the annual amount of plant tailgate electricity.

(4) For new powerplants, the lessee's generating costs for the first deduction period shall be based on estimated expenses (including overhead) for operating and maintaining the powerplant. For subsequent deduction periods, the generating costs shall be estimated based on the lessee's actual operating and maintenance expenses for the previous period adjusted for decreases or increases that the lessee knows will affect the deduction in the current period.

(c) Under no circumstances shall the generating deduction plus the transmission deduction determined pursuant to § 206.353 of this subpart reduce the royalty value of the geothermal resource to zero.

(d)(1) If the actual generating deduction determined at the end of the annual reporting period is less than the amount the lessee estimated and used in the netback procedure during the reporting period, the lessee shall be required to pay additional royalties retroactive to the first month of the reporting period, plus interest computed pursuant to 30 CFR 218.302. If the actual generating deduction is greater than the amount applied in the netback calculation, the lessee shall be entitled to a credit.

(2) Lessees must submit corrected Forms MMS–2014 to reflect adjustments to royalty payments in accordance with MMS instructions.

(e)(1) All generating deductions are subject to review, audit, and adjustment. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual generating deduction and adjust royalty values accordingly.

(2) Pursuant to subpart H of 30 CFR part 212, the lessee must maintain all data and records supporting its generating deduction. These data and records must be made available to MMS and other authorized personnel upon request, and shall be maintained in a confidential manner in accordance with applicable laws and regulations pursuant to § 206.352 of this subpart.

(f) A one-time refund of royalties equal to the royalty amount of actual dismantlement costs attributable to the powerplant that are in excess of actual income attributable to the salvage of the powerplant will be allowed at the completion of the dismantlement and salvage operations.

§ 206.355 Valuation standards for direct utilization.

(a) The value of geothermal resources produced for leases subject to this subpart and used in direct utilization processes shall be determined pursuant to this section.

(b)(1)(i) The value of geothermal resources that are sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (b)(1)(iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit.

(ii) In conducting these reviews and audits, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the geothermal resource. If the contract does not reflect the total consideration, MMS may require that the geothermal resource sold pursuant to that contract be valued in accordance with paragraph (d) of this section. Value shall not be less than the gross proceeds accruing to the lessee, including any additional consideration received.

(iii) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the geothermal resource because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the

lessor, MMS shall require the geothermal resource to be valued pursuant to paragraph (d) of this section and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) The MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the geothermal resource.

(c)(1) The value of geothermal resources subject to this section that are sold under a non-arm's-length contract shall be determined in accordance with the first applicable of the following paragraphs:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract provided that those gross proceeds are not less than the gross proceeds derived from or paid under the lowest-priced available comparable arm's-length contract for sales of geothermal resources to the lessee-affiliate's same direct utilization facility (the ''minimun value''). If the gross proceeds under the lessee's non-arm's-length contract are less than the ''minimum value'' under available comparable arm's-length contracts, or if there are no available comparable arm's-length contracts, value will be determined by the weighted average of the gross proceeds established under arm's-length contracts for the sale of significant quantities of geothermal resources to the same direct utilization facility. Available contracts will mean contracts in the possession of the lessee, the lessee's affiliate, or MMS. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Time of execution, duration, terms, quality of the geothermal resource, volume, dedication to the same direct utilization facility, and other factors that may be appropriate to reflect the value of the resource;

(ii) The equivalent value of the least expensive, reasonable alternative energy source (fuel). The equivalent value of the least expensive, reasonable alternative energy source shall be based on the amount of thermal energy that would otherwise be used by the direct utilization process in place of the geothermal resource. That amount of thermal energy (in Btu's) displaced by the geothermal resource shall be determined by the equation

$$\text{thermal energy displaced} = \frac{(h_{in} - h_{out}) \times \text{density} \times 0.133681 \times \text{volume}}{\text{efficiency factor}},$$

where h_{in} is the enthalpy in Btu's/lb at the utilization facility inlet (based on measured inlet temperature), h_{out} is the enthalpy in Btu's/lb at the facility outlet (based on measured outlet temperature), density is in lbs/cu ft based on inlet temperature, the factor 0.133681 (cu ft/gal) converts gallons to cubic feet, and volume is the quantity of geothermal fluid in gallons produced at the wellhead or measured at an approved point. The efficiency of the alternative energy source shall be 0.7 for coal and 0.8 for oil, natural gas, and other fuels derived from oil and natural gas, or an efficiency factor proposed by the lessee and approved by MMS. The methods of measuring resource parameters (temperature, volume, etc.) and the frequency of computing and accumulating the amount of thermal energy displaced shall be determined and approved by BLM; or

(iii) A value determined by any other reasonable valuation method approved by MMS.

(2) Valuations made pursuant to this paragraph are subject to the notification requirements of paragraph (e) of this section.

(d)(1) The value of geothermal resources subject to this section that are not subject to a sales transaction but are instead used by the lessee in its own direct utilization facility (''no sales'' geothermal resources) shall be determined in accordance with the first applicable of the following paragraphs:

(i) The weighted average of the gross proceeds established in arm's-length contracts for the purchase of significant quantities of geothermal resources to operate the lessee's same direct utilization facility. In evaluating

the acceptability of arm's-length contracts, the following factors shall be considered: Time of execution, duration, terms, volume, quality of resource, and such other factors as may be appropriate to reflect the value of the resource;

(ii) The equivalent value of the least expensive, reasonable alternative energy source (fuel). The equivalent value of the least expensive, reasonable alternative energy source shall be based on the amount of thermal energy that would otherwise be used by the direct utilization process in place of the geothermal resource. That amount of thermal energy (in Btu's) displaced by the geothermal resource shall be determined by the equation

$$\text{thermal energy displaced} = \frac{(h_{in} - h_{out}) \times \text{density} \times 0.133681 \times \text{volume}}{\text{efficiency factor}},$$

where h_{in} is the enthalpy in Btu's/lb at the utilization facility inlet (based on measured inlet temperature), h_{out} is the enthalpy in Btu's/lb at the facility outlet (based on measured outlet temperature), density is in lbs/cu ft based on inlet temperature, the factor 0.133681 (cu ft/gal) converts gallons to cubic feet, and volume is the quantity of geothermal fluid in gallons produced at the wellhead or measured at an approved point. The efficiency of the alternative energy source shall be 0.7 for coal and 0.8 for oil, natural gas, and other fuels derived from oil and natural gas, or an efficiency factor proposed by the lessee and approved by MMS. The methods of measuring resource parameters (temperature, volume, etc.) and the frequency of computing and accumulating the amount of thermal energy displaced shall be determined and approved by BLM; or

(iii) A value determined by any other reasonable valuation method approved by MMS.

(2) Valuations made pursuant to this paragraph are subject to the notification requirements of paragraph (e) of this section.

(e)(1) Pursuant to subpart H of 30 CFR part 212, the lessee shall retain all data relevant to the determination of royalty value, particularly where the value is determined pursuant to paragraph (c) or (d) of this section. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Upon request, lessees shall make available to authorized MMS representatives or to other authorized persons any and all contracts for the sale or other disposition of the lease production, and any arm's-length sales and other data for like-quality production sold, purchased, or otherwise obtained by the lessee from the field as may be necessary to support a value determination.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c) or (d) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c) or (d) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.302. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method and may use that method in determining value, for royalty purposes, until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making

a value determination, MMS may use any of the valuation criteria consistent with this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production, for royalty purposes, be less than the gross proceeds accruing to the lessee where geothermal energy is directly sold.

(i) The lessee is required to place geothermal resources in marketable condition and to deliver geothermal resources to the direct utilization facility at no cost to the Federal lessor. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the geothermal resource in marketable condition or to deliver it to the direct utilization facility.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to the contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee shall owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of geothermal resources.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support value determinations is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable laws and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department, 43 CFR part 2.

[56 FR 57276, Nov. 8, 1991; 57 FR 12376, Apr. 9, 1992]

§ 206.356 Valuation standards for byproducts.

(a) The value of geothermal byproducts, including commercially demineralized water, shall be determined pursuant to this section, less applicable byproducts transportation allowances determined pursuant to §§ 206.357 and 206.358 of this subpart.

(b)(1)(i) The value of byproducts that are sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii) and (b)(1)(iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to the seller for the byproducts. If the contract does not reflect the total consideration, MMS may require that the byproducts sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the

lessee, including any additional consideration received .

(iii) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, MMS shall require that the byproduct production be valued pursuant to paragraph (c) of this section and in accordance with the notification requirements of paragraph (d) of this section. If MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported byproduct value.

(2) The MMS may require a lessee to certify that the provisions in its arm's-length contract include all of the consideration to be paid by the buyer, either directly or indirectly, for the byproduct.

(c) The value of byproducts that are sold pursuant to a non-arm's-length contract or that are utilized by the lessee (no sales), except demineralized water used for the benefit of the lease pursuant to paragraph (b)(2) of § 202.351 of this subpart, shall be determined in accordance with the first applicable of the following paragraphs:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are not less than the gross proceeds derived from or paid under the lowest-priced available comparable arm's-length contract for sales, purchases, or other dispositions of like-quality byproducts in the field or, if necessary to obtain a representative sample, from the same area (the ''minimum value''). If the gross proceeds under the lessee's non-arm's-length contract are less than the ''minimum value'' under available comparable arms length contracts, or if there are no available comparable arm's-length contracts, value will be determined by the weighted average of the gross proceeds established under arm's-length contracts for the sale of like-quality products in the field or, if necessary to obtain a representative sample, from the same area. Available contracts will mean contracts in the possession of the lessee, the lessee's affiliate, or MMS. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Field or area, price, time of execution, duration, terms, quality of the byproduct, volume, market or markets served, and other factors that may be appropriate to reflect the value of the byproduct;

(2) Other relevant matters including, but not limited to, published or publicly available spot-market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain byproducts; or

(3) A netback method or any other reasonable method used to determine value.

(d)(1) Pursuant to subpart H of 30 CFR part 212, the lessee shall retain all data relevant to the determination of royalty value, particularly where the value is determined pursuant to paragraph (c) of this section. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Upon request, lessees shall make available to authorized MMS representatives or to other authorized persons any and all contracts and/or invoices for the sale or other disposition of the byproducts, and any arm's-length sales and other data for like-quality production sold, purchased, or otherwise obtained by the lessee from the field or other area as may be necessary to support a value determination.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is

a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS–2014 using a valuation method authorized by paragraph (c) of this section, and each time there is a change in a method under paragraph (c) of this section.

(e) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.302. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method and may use that method in determining value, for royalty purposes, until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria consistent with this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of the section, under no circumstances shall the value of byproducts for royalty purposes be less than the gross proceeds accruing to the lessee, less applicable byproduct transportation allowances determined pursuant to §§ 206.357 and 206.358 of this subpart.

(h) The lessee is required to place the byproducts in marketable condition at no cost to the Federal Government. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the byproducts in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to the contract, and may be retroactively applied to value byproducts, for royalty purposes, for a period not to exceed 2 years, unless MMS approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of byproducts.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) Certain information submitted to MMS to support valuation proposals, including byproduct transportation allowances pursuant to §§ 206.357 and 206.358 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552. Any data specified by the act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable laws and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department, 43 CFR part 2.

§ 206.357 Byproduct transportation allowances—general.

(a) Where the value of byproducts has been determined at a point off the geothermal lease, unit, or participating area, MMS shall allow a deduction in determining value, for royalty purposes, for the lessee's reasonable, actual costs incurred to:

(1) Transport the byproducts from a Federal lease, unit, or participating area to a sales point or point of delivery that is off the lease, unit, or participating area; or

(2) Transport the byproducts from a Federal lease, unit, or participating area, or from a geothermal utilization facility to a byproduct recovery facility when that byproduct recovery facility is off the lease, unit, or participating area and, if applicable, from the recovery facility to a sales point or point of delivery off the lease, unit, or participating area. Costs for transporting geothermal fluids from the lease to the geothermal utilization facility, whether on or off the lease, shall not be included in the transportation allowance.

(b) Under no circumstances shall the byproduct transportation allowance authorized by paragraph (a) of this section reduce the value of the byproducts under any selling arrangement to zero.

(c)(1) When byproducts are transported from a lease, unit, participating area, or geothermal utilization facility to a byproduct recovery facility, the lessee is not required to allocate transportation costs between the quantity of marketable byproducts and the rejected waste material. The byproduct transportation allowance shall be authorized for the total production that is transported. Byproduct transportation allowances shall be expressed as a cost per unit of marketable byproducts transported.

(2) For byproducts that are extracted on the lease, unit, or participating area, or at the geothermal utilization facility, the byproduct transportation allowance shall be authorized for the total production that is transported to a point of sale off the lease, unit, or participating area. Byproduct transportation allowances shall be expressed as a cost per unit of byproduct transported.

(3) Transportation costs shall be authorized as allowances only when the transported byproduct is sold, delivered, or otherwise utilized by the lessee and royalties are reported and paid.

(d) Byproduct transportation allowances are subject to monitoring, review, and audit. If, after a review and/or audit, MMS determines that a lessee has improperly determined a byproduct transportation allowance authorized by this section, then the lessee shall pay any additional royalties plus interest determined in accordance with 30 CFR 218.302, or shall be entitled to a credit without interest.

(e) If byproducts produced from Federal and non-Federal leases are commingled for transportation, lessees shall not disproportionately allocate transportation costs to Federal lease production.

(f) Upon request, the lessee shall make available to authorized MMS representatives or to other authorized persons all transportation contracts and all other information as may be necessary to support a byproduct transportation allowance.

(g) Byproduct transportation allowances are to be reported as separate lines on Form MMS–2014.

§ 206.358 Determination of byproduct transportation allowances.

(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the byproducts under that contract, subject to monitoring, review, audit, and possible future adjustments. The MMS's prior approval is not required before a lessee may deduct costs incurred under an arm's-length transportation contract.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the

total consideration paid, MMS may require that the byproduct transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If MMS determines that the consideration paid pursuant to an arm's-length byproduct transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, MMS shall require that the byproduct transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not established on a dollars-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the byproduct transportation allowance shall be based upon the lessee's reasonable actual costs. All byproduct transportation allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior MMS approval of byproduct transportation allowances is not required for non-arm's-length or no-contract situations.

(2) The byproduct transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the capital investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable assets, including costs of delivery and installation of capital equipment, that are an integral part of the transportation system. A return on capital invested in the purchase of real estate to locate the byproduct transportation facilities may be allowed provided that the lessee demonstrates the necessity for such purchase, the purchased land is not on a Federal geothermal lease, and MMS approves the deduction; the rate of return shall be the same rate determined in paragraph (b)(2)(v) of this section.

(i) Allowable operating expenses include operations supervision and engineering, operations labor, fuel, utilities, materials, ad valorem property taxes, rent, supplies, and any other allocable and attributable operating expenses that the lessee can document.

(ii) Allowable maintenance expenses include maintenance of the transportation system, maintenance of equipment, maintenance labor, and other directly allocable and attributable maintenance expenses that the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) To compute costs associated with capital investment, a lessee may use either paragraph (b)(2)(iv)(A) or (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, the lessee must use a straight-line depreciation method based on, as appropriate, either the life of equipment or the life of the geothermal project that the transportation system services. After an election is made, the lessee may not change methods. A change in ownership of a transportation system shall

not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value. The rate of return used to compute the return on undepreciated capital investment shall be determined pursuant to paragraph (b)(2)(v) of this section.

(B) To compute a return on capital investment, the allowed cost shall be the amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation.

(v) The rate of return shall be Standard and Poor's industrial BBB bond rate. The rate of return shall be the monthly average rate as published in *Standard and Poor's Bond Guide* for the first month of the annual reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period.

Subpart I—OCS Sulfur [Reserved]

Subpart J—Indian Coal

SOURCE: 61 FR 5481, Feb. 12, 1996, unless otherwise noted.

§ 206.450 Purpose and scope.

(a) This subpart prescribes the procedures to establish the value, for royalty purposes, of all coal from Indian Tribal and allotted leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma).

(b) If the specific provisions of any statute, treaty, or settlement agreement between the Indian lessor and a lessee resulting from administrative or judicial litigation, or any coal lease subject to the requirements of this subpart, are inconsistent with any regulation in this subpart, then the statute, treaty, lease provision, or settlement shall govern to the extent of that inconsistency.

(c) All royalty payments are subject to later audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian coal leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

§ 206.451 Definitions.

Ad valorem lease means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

Allowance means an approved, or an MMS-initially accepted deduction in determining value for royalty purposes. Coal washing allowance means an allowance for the reasonable, actual costs incurred by the lessee for coal washing, or an approved or MMS-initially accepted deduction for the costs of washing coal, determined pursuant to this subpart. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant, or an approved MMS-initially accepted deduction for costs of such transportation, determined pursuant to this subpart.

Area means a geographic region in which coal has similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

Arm's-length contract means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: ownership in excess of 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if

it demonstrates actual or legal control, including the existence of interlocking directorates. Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month, as well as when the contract was executed.

Audit means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Indian leases.

BIA means the Bureau of Indian Affairs of the Department of the Interior.

BLM means the Bureau of Land Management of the Department of the Interior.

Coal means coal of all ranks from lignite through anthracite.

Coal washing means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

Contract means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

Gross proceeds (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Indian lessor. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

Indian allottee means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

Indian Tribe means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

Lease means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for an Indian coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

Lessee means any person to whom the Indian Tribe or an Indian allottee issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

Like-quality coal means coal has similar chemical and physical characteristics.

Marketable condition means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

Mine means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

MMS means the Minerals Management Service of the Department of the Interior.

Net-back method means a method for calculating market value of coal at the lease or mine. Under this method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

Net output means the quantity of washed coal that a washing plant produces.

Person means by individual, firm, corporation, association, partnership, consortium, or joint venture.

Selling arrangement means the individual contractual arrangements under which sales or dispositions of coal are made to a purchaser.

Spot market price means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

§ 206.452 Coal subject to royalties—general provisions.

(a) All coal (except coal unavoidably lost as determined by BLM pursuant to 43 CFR group 3400) from an Indian lease subject to this part is subject to royalty. This includes coal used, sold, or otherwise disposed of by the lessee on or off the lease.

(b) If a lessee receives compensation for unavoidably lost coal through insurance coverage or other arrangements, royalties at the rate specified in the lease are to be paid on the amount of compensation received for the coal. No royalty is due on insurance compensation received by the lessee for other losses.

(c) If waste piles or slurry ponds are reworked to recover coal, the lessee shall pay royalty at the rate specified in the lease at the time the recovered coal is used, sold, or otherwise finally disposed of. The royalty rate shall be that rate applicable to the production method used to initially mine coal in the waste pile or slurry pond; i.e., underground mining method or surface mining method. Coal in waste pits or slurry ponds initially mined from Indian leases shall be allocated to such leases regardless of whether it is stored on Indian lands. The lessee shall maintain accurate records to determine to which individual Indian lease coal in the waste pit or slurry pond should be allocated. However, nothing in this section requires payment of a royalty on coal for which a royalty has already been paid.

§ 206.453 Quality and quantity measurement standards for reporting and paying royalties.

(a) For leases subject to § 206.456 of this subpart, the quality of coal on which royalty is due shall be reported on the basis of percent sulfur, percent ash, and number of British thermal units (Btu) per pound of coal. Coal quality determinations shall be made at intervals prescribed in the lessee's sales contract. If there is no contract, or if the contract does not specify the intervals of coal quality determination, the lessee shall propose a quality test schedule to MMS. In no case, however, shall quality tests be performed less than quarterly using standard industry-recognized testing methods. Coal quality information shall be reported on the appropriate forms required under 30 CFR part 216.

(b) For all leases subject to this subpart, the quantity of coal on which royalty is due shall be measured in short tons (of 2,000 pounds each) by methods prescribed by the BLM. Coal quantity information shall be reported on appropriate forms required under 30 CFR part 216 and on the Report of Sales and Royalty Remittance, Form MMS–2014, as required under 30 CFR part 210.

§ 206.454 Point of royalty determination.

(a) For all leases subject to this subpart, royalty shall be computed on the basis of the quantity and quality of Indian coal in marketable condition measured at the point of royalty measurement as determined jointly by BLM and MMS.

(b) Coal produced and added to stockpiles or inventory does not require payment of royalty until such coal is later used, sold, or otherwise finally disposed of. MMS may ask BLM or BIA to increase the lease bond to protect the lessor's interest when BLM determines

that stockpiles or inventory become excessive so as to increase the risk of degradation of the resource.

(c) The lessee shall pay royalty at a rate specified in the lease at the time the coal is used, sold, or otherwise finally disposed of, unless otherwise provided for at § 206.455(d) of this subpart.

§ 206.455 Valuation standards for cents-per-ton leases.

(a) This section is applicable to coal leases on Indian Tribal and allotted Indian lands (except leases on the Osage Indian Reservation, Osage County, Oklahoma) which provide for the determination of royalty on a cents-per-ton (or other quantity) basis.

(b) The royalty for coal from leases subject to this section shall be based on the dollar rate per ton prescribed in the lease. That dollar rate shall be applicable to the actual quantity of coal used, sold, or otherwise finally disposed of, including coal which is avoidably lost as determined by BLM pursuant to 43 CFR part 3400.

(c) For leases subject to this section, there shall be no allowances for transportation, removal of impurities, coal washing, or any other processing or preparation of the coal.

(d) When a coal lease is readjusted pursuant to 43 CFR part 3400 and the royalty valuation method changes from a cents-per-ton basis to an ad valorem basis, coal which is produced prior to the effective date of readjustment and sold or used within 30 days of the effective date of readjustment shall be valued pursuant to this section. All coal that is not used, sold, or otherwise finally disposed of within 30 days after the effective date of readjustment shall be valued pursuant to the provisions of § 206.456 of this subpart, and royalties shall be paid at the royalty rate specified in the readjusted lease.

§ 206.456 Valuation standards for ad valorem leases.

(a) This section is applicable to coal leases on Indian Tribal and allotted Indian lands (except leases on the Osage Indian Reservation, Osage County, Oklahoma) which provide for the determination of royalty as a percentage of the amount of value of coal (ad valorem). The value for royalty purposes of coal from such leases shall be the value of coal determined pursuant to this section, less applicable coal washing allowances and transportation allowances determined pursuant to §§ 206.457 through 206.461 of this subpart, or any allowance authorized by § 206.464 of this subpart. The royalty due shall be equal to the value for royalty purposes multiplied by the royalty rate in the lease.

(b)(1) The value of coal that is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(2), (b)(3), and (b)(5) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the coal produced. If the contract does not reflect the total consideration, then MMS may require that the coal sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be based on less than the gross proceeds accruing to the lessee for the coal production, including the additional consideration.

(3) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the coal production be valued pursuant to paragraphs (c)(2)(ii), (c)(2)(iii), (c)(2)(iv), or (c)(2)(v) of this section, and in accordance with the notification requirements of paragraph (d)(3) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported coal value.

(4) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the coal production.

(5) The value of production for royalty purposes shall not include payments received by the lessee pursuant to a contract which the lessee demonstrates, to MMS' satisfaction, were not part of the total consideration paid for the purchase of coal production.

(c)(1) The value of coal from leases subject to this section and which is not sold pursuant to an arm's-length contract shall be determined in accordance with this section.

(2) If the value of the coal cannot be determined pursuant to paragraph (b) of this section, then the value shall be determined through application of other valuation criteria. The criteria shall be considered in the following order, and the value shall be based upon the first applicable criterion:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition of produced coal by other than an arm's-length contract), provided that those gross proceeds are within the range of the gross proceeds derived from, or paid under, comparable arm's-length contracts between buyers and sellers neither of whom is affiliated with the lessee for sales, purchases, or other dispositions of like-quality coal produced in the area. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of coal, quantity, and such other factors as may be appropriate to reflect the value of the coal;

(ii) Prices reported for that coal to a public utility commission;

(iii) Prices reported for that coal to the Energy Information Administration of the Department of Energy;

(iv) Other relevant matters including, but not limited to, published or publicly available spot market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the salability of certain types of coal;

(v) If a reasonable value cannot be determined using paragraphs (c)(2)(i), (c)(2)(ii), (c)(2)(iii), or (c)(2)(iv) of this section, then a net-back method or any other reasonable method shall be used to determine value.

(3) When the value of coal is determined pursuant to paragraph (c)(2) of this section, that value determination shall be consistent with the provisions contained in paragraph (b)(5) of this section.

(d)(1) Where the value is determined pursuant to paragraph (c) of this section, that value does not require MMS' prior approval. However, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) An Indian lessee will make available upon request to the authorized MMS or Indian representatives, or to the Inspector General of the Department of the Interior or other persons authorized to receive such information, arm's-length sales and sales quantity data for like-quality coal sold, purchased, or otherwise obtained by the lessee from the area.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraphs (c)(2)(ii), (c)(2)(iii), (c)(2)(iv), or (c)(2)(v) of this section. The notification shall be by letter to the Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this section is a one-time notification due no later than the month the lessee first reports royalties on the Form MMS–2014 using a valuation method authorized by paragraphs (c)(2)(ii), (c)(2)(iii), (c)(2)(iv), or (c)(2)(v) of this section, and each time there is a change in a method under paragraphs (c)(2)(iv) or (c)(2)(v) of this section.

(e) If MMS determines that a lessee has not properly determined value, the lessee shall be liable for the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due

based upon the value established by MMS. The lessee shall also be liable for interest computed pursuant to 30 CFR 218.202. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of this section, under no circumstances shall the value for royalty purposes be less than the gross proceeds accruing to the lessee for the disposition of produced coal less applicable provisions of paragraph (b)(5) of this section and less applicable allowances determined pursuant to §§ 206.457 through 206.461 and § 206.464 of this subpart.

(h) The lessee is required to place coal in marketable condition at no cost to the Indian lessor. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds has been reduced because the purchaser, or any other person, is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the coal in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract, and may be retroactively applied to value for royalty purposes for a period not to exceed two years, unless MMS approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of coal.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Indian Tribes or allottees until the audit period is formally closed.

(k) Certain information submitted to MMS to support valuation proposals, including transportation, coal washing, or other allowances pursuant to §§ 206.457 through 206.461 and § 206.464 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 522. Any data specified by the Act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from MMS or such lessor's lessee directly under the terms of the lease or applicable law.

§ 206.457 Washing allowances—general.

(a) For ad valorem leases subject to § 206.456 of this subpart, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual

costs incurred to wash coal, unless the value determined pursuant to § 206.456 of this subpart was based upon like-quality unwashed coal. Under no circumstances shall the washing allowance and the transportation allowance authorized by § 206.461 of this subpart reduce the value for royalty purposes to zero.

(b) If MMS determines that a lessee has improperly determined a washing allowance authorized by this section, then the lessee shall be liable for any additional royalties, plus interest determined in accordance with 30 CFR 218.202, or shall be entitled to a credit, without interest.

(c) Lessees shall not disproportionately allocate washing costs to Indian leases.

(d) No cost normally associated with mining operations and which are necessary for placing coal in marketable condition shall be allowed as a cost of washing.

(e) Coal washing costs shall only be recognized as allowances when the washed coal is sold and royalties are reported and paid.

§ 206.458 Determination of washing allowances.

(a) *Arm's-length contracts.* (1) For washing costs incurred by a lessee pursuant to an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. However, before any deduction may be taken, the lessee must submit a completed page one of Form MMS–4292, Coal Washing Allowance Report, in accordance with paragraph (c)(1) of this section. A washing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4292 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then MMS may require that the washing allowance be determined in accordance with paragraph (b) of this section.

(3) If MMS determines that the consideration paid pursuant to an arm's-length washing contract does not reflect the reasonable value of the washing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the washing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the washing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's washing costs.

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior MMS approval of washing allowances is not required for non-arm's-length or no contract situations. However, before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS–4292 in accordance with paragraph (c)(2) of this section. A washing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4292 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

MMS will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its actual washing allowance.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the wash plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the wash plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a wash plant shall not alter the depreciation schedule established by the original operator/lessee for purposes of the allowance calculation. With or without a change in ownership, a wash plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the allowable capital investment in the wash plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent washing allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) With the exception of those washing allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS–4292 prior to, or at the same time, as the washing allowance determined pursuant to an arm's-length contract is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4292 received by the end of the month that the Form MMS–2014 is due shall be considered to be received timely.

(ii) The initial Form MMS–4292 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a washing allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS–4292 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) MMS may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Washing allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those washing allowances specified in paragraphs (c)(2)(v) and (c)(2)(vii) of this section, the lessee shall submit an initial Form MMS–4292 prior to, or at the same time as, the washing allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on Form MMS–2014, Report of Sales and Royalty Remittance. A Form MMS–4292 received by the end of the month that the Form MMS–2014 is due shall be considered to be timely received. The initial reporting may be based on estimated costs.

(ii) The initial Form MMS–4292 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a washing allowance and shall continue until the end of the calendar year, or until the washing under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS–4292 containing the actual costs for the previous reporting period. If coal washing is continuing, the lessee shall include on Form MMS–4292 its estimated costs for the next calendar year. The estimated coal washing allowance shall be based on the actual costs for the previous period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form MMS–4292 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new wash plants, the lessee's initial Form MMS–4292 shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the plant, or if such data are not available, the lessee shall use estimates based upon industry data for similar coal wash plants.

(v) Washing allowances based on non-arm's-length or no contract situations which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used by the lessee to prepare its Forms MMS–4292. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(3) MMS may establish coal washing allowance reporting dates for individual leases different from those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Washing allowances must be reported as a separate line on the Form MMS–2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a washing allowance on its Form MMS–2014 without complying with the requirements of this section, the lessee shall be liable for interest on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments.* (1) If the actual coal washing allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed pursuant to 30 CFR 218.202, retroactive to the first month the lessee is authorized to deduct a washing allowance. If the actual washing allowance is greater than the amount the lessee has estimated and taken during the reporting period, the lessee shall be entitled to a credit, without interest.

(2) The lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other washing cost determinations.* The provisions of this section shall apply to determine washing costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of washing costs.

§ 206.459 Allocation of washed coal.

(a) When coal is subjected to washing, the washed coal must be allocated to the leases from which it was extracted.

(b) When the net output of coal from a washing plant is derived from coal obtained from only one lease, the quantity of washed coal allocable to the lease will be based on the net output of the washing plant.

(c) When the net output of coal from a washing plant is derived from coal obtained from more than one lease, unless determined otherwise by BLM, the quantity of net output of washed coal allocable to each lease will be based on the ratio of measured quantities of coal delivered to the washing plant and washed from each lease compared to the total measured quantities of coal delivered to the washing plant and washed.

§ 206.460 Transportation allowances—general.

(a) For ad valorem leases subject to § 206.456 of this subpart, where the value for royalty purposes has been determined at a point remote from the lease or mine, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to:

(1) Transport the coal from an Indian lease to a sales point which is remote from both the lease and mine; or

(2) Transport the coal from an Indian lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point. In-mine transportation costs shall not be included in the transportation allowance.

(b) Under no circumstances shall the washing allowance and the transportation allowance authorized by § 206.456 of this subpart reduce the value of coal under any selling arrangement to zero.

(c)(1) When coal transported from a mine to a wash plant is eligible for a transportation allowance in accordance with this section, the lessee is not required to allocate transportation costs between the quantity of clean coal output and the rejected waste material. The transportation allowance shall be authorized for the total production

which is transported. Transportation allowances shall be expressed as a cost per ton of cleaned coal transported.

(2) For coal that is not washed at a wash plant, the transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of coal transported.

(3) Transportation costs shall only be recognized as allowances when the transported coal is sold and royalties are reported and paid.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this section, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.202, or shall be entitled to a credit, without interest.

(e) Lessees shall not disproportionately allocate transportation costs to Indian leases.

§ 206.461 Determination of transportation allowances.

(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. However, before any deduction may be taken, the lessee must submit a completed page one of Form MMS–4293, Coal Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4293 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior MMS approval of transportation allowances is not required for non-arm's-length or no contract situations. However, before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS–4293 in accordance with paragraph (c)(2) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS–4293 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the

lessee. MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or paragraph (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(B)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average as published in Standard and Poor's Bond Guide for the first month of the reporting period of which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) A lessee may apply to MMS for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (b)(2) of this section. MMS will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency for Indian leases. MMS shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if:

(i) No Federal regulatory agency cost analysis exists and the Federal regulatory agency has declined to investigate pursuant to MMS timely objections upon filing; and

(ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements.* (1) *Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS–4293 prior to, or at the same time as, the transportation allowance determined pursuant to an arm's-length contract is reported on Form MMS–2014, Reports of Sales and Royalty Remittance.

(ii) The initial Form MMS–4293 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS–4293 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period). Lessees may request special reporting procedures in unique allowance reporting situations, such as those related to spot sales.

(iv) MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances that are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v) and (c)(2)(vii) of this section, the lessee shall submit an initial Form MMS–4293 prior to, or at the same time as, the transportation allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on Form MMS–2014, Report of Sales and Royalty Remittance. The initial report may be based on estimated costs.

(ii) The initial Form MMS–4293 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the transportation under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS–4293 containing the actual costs for the previous reporting period. If the transportation is continuing, the lessee shall include on Form MMS–4293 its estimated costs for the next calendar year. The estimated transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments that are based on the lessee's knowledge of decreases or increases that will affect the allowance. Form MMS–4293 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS–4293 shall include estimates of the allowable transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for

the transportation system, or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no contract-based transportation allowances that are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS–4293. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(viii) If the lessee is authorized to use its Federal-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) MMS may establish reporting dates for individual lessees different than those specified in this paragraph in order to provide more effective administration. Lessees will be notified as to any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on Form MMS–2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a transportation allowance on its Form MMS–2014 without complying with the requirements of this section, the lessee shall be liable for interest on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS–2014 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest, computed pursuant to 30 CFR 218.202, retroactive to the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has estimated and taken during the reporting period, the lessee shall be to a credit, without interest.

(2) The lessee must submit a corrected Form MMS–2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

§ 206.462 Contract submission.

(a) The lessee and other payors shall submit to MMS, upon request, contracts for the sale of coal from ad valorem leases subject to this subpart. MMS must receive the contracts within a reasonable period of time, as specified by MMS. Lessees shall include as part of the submittal requirements any contracts, agreements, contract amendments, or other documents that affect the gross proceeds received for the sale of coal, as well as any other information regarding any consideration received for the sale or disposition of coal that is not included in such contracts. At the time of its contract submittals, MMS may require the lessee to certify in writing that it has provided all documents and information that reflect the total consideration provided by purchasers of coal from ad valorem leases subject to this subpart. Information requested under this section may include contracts for both ad valorem and cents-per-ton leases and shall be available in the lessee's offices during normal business hours or provided to

MMS at such time and in such manner as may be requested by authorized Department of the Interior personnel. Any oral sales arrangement negotiated by the lessee must be placed in a written form and be retained by the lessee. Nothing in this section shall be construed to limit the authority of MMS to obtain or have access to information pursuant to 30 CFR part 212.

(b) Lessees and other payors shall designate, for each contract submitted pursuant to this section, whether the contract in arm's-length or non-arm's-length.

(c) A lessee's or other payor's determination that its contract is arm's-length is subject to future audit to verify that the contract meets the criteria of the arm's-length contract definition in § 206.251 of this subpart.

(d) Information required to be submitted under this section that constitutes trade secrets and commercial and financial information that is identified as privileged or confidential shall not be available for public inspection or made public or disclosed without the consent of the lessee or other payor, except as otherwise provided by law or regulation.

§ 206.463 In-situ and surface gasification and liquefaction operations.

In an ad valorem Federal coal lease is developed by in-situ or surface gasification or liquefaction technology, the lessee shall propose the value of coal for royalty purposes to MMS. MMS will review the lessee's proposal and issue a value determination. The lessee may use its proposed value until MMS issues a value determination.

§ 206.464 Value enhancement of marketable coal.

If, prior to use, sale, or other disposition, the lessee enhances the value of coal after the coal has been placed in marketable condition in accordance with § 206.456(h) of this subpart, the lessee shall notify MMS that such processing is occurring or will occur. The value of that production shall be determined as follows:

(a) A value established for the feedstock coal in marketable condition by application of the provisions of § 206.465(c)(2) (i) through (iv) of this subpart; or,

(b) In the event that a value cannot be established in accordance with paragraph (a) of this section, then the value of production will be determined in accordance with § 206.456(c)(2)(v) of this subpart and the value shall be the lessee's gross proceeds accruing from the disposition of the enhanced product, reduced by MMS-approved processing costs and procedures including a rate of return on investment equal to two times the Standard and Poor's BBB bond rate applicable under § 206.458(b)(2)(v) of this subpart.

PART 207—SALES AGREEMENTS OR CONTRACTS GOVERNING THE DISPOSAL OF LEASE PRODUCTS

Subpart A—General Provisions

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Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

AUTHORITY: 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*; 25 U.S.C. 396a *et seq.*; 25 U.S.C. 2101 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq.*; 30 U.S.C. 1001 *et seq.*; 30 U.S.C. 1701 *et seq.*; 31 U.S.C. 3716 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.*; 43 U.S.C. 1331 *et seq.*; and 43 U.S.C. 1801 *et seq.*

SOURCE: 53 FR 1225, Jan. 15, 1988, unless otherwise noted.

Subpart A—General Provisions

§207.1 Required recordkeeping.

(a) The information collection and recordkeeping requirements contained in this part have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned OMB Clearance Number 1010–0061. The information collected will be used to determine a proper transportation allowance for the cost of transporting royalty oil from the lease to a delivery point remote from the lease. The information is required in order to obtain a benefit and is collected in accordance with the Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. 1701 *et seq.*

(b) Public reporting burden is estimated to average 30 minutes per year for each record keeper to maintain copies of sales contracts, agreements, or other documents relevant to the valuation of production. Send any comments regarding this burden estimate or any other aspect of this requirement to the Information Collection Clearance Officer, Minerals Management Service, 381 Elden Street, Herndon, VA 22070, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project 1010–0061, Washington, DC 20503.

[57 FR 41864, Sept. 14, 1992, as amended at 58 FR 64901, Dec. 10, 1994]

§207.2 Definitions.

The definitions in part 206 of this title are applicable to this part.

§207.3 Contracts made pursuant to new form leases.

On November 29, 1950 (15 FR 8585), a new lease form was adopted (Form 4–1158, 15 FR 8585) containing provisions whereby the lessee agrees that nothing in any contract or other arrangement made for the sale or disposal of oil, gas, natural gasoline, and other products of the leased land, shall be construed as modifying any of the provisions of the lease, including, but not limited to, provisions relating to gas waste, taking royalty-in-kind, and the method of computing royalties due as based on a minimum valuation and in accordance with the oil and gas valuation regulations. A contract or agreement pursuant to a lease containing such provisions may be made without obtaining prior approval of the United States as lessor, but must be retained as provided in §207.5 of this subpart.

§207.4 Contracts made pursuant to old form leases.

(a) Old form leases are those containing provisions prohibiting sales or disposal of oil, gas, natural gasoline, and other products of the lease except in accordance with a contract or other arrangement approved by the Secretary of the Interior, or by the Director of the Minerals Management Service or his/her representative. A contract or agreement made pursuant to an old form lease may be made without obtaining approval if the contract or agreement contains either the substance of or is accompanied by the stipulation set forth in paragraph (b) of this section, signed by the seller (lessee or operator).

(b) The stipulation, the substance of which must be included in the contract, or be made the subject matter of a separate instrument properly identifying the leases affected thereby, is as follows:

> It is hereby understood and agreed that nothing in the written contract or in any approval thereof shall be construed as affecting any of the relations between the United States and its lessee, particularly in matters of gas waste, taking royalty in kind, and the method of computing royalties due as based on a minimum valuation and in accordance with the terms and provisions of the oil and gas valuation regulations applicable to the lands covered by said contract.

§207.5 Contract and sales agreement retention.

Copies of all sales contracts, posted price bulletins, etc., and copies of all agreements, other contracts, or other documents which are relevant to the valuation of production are to be maintained by the lessee and made available upon request during normal working hours to authorized MMS, State or Indian representatives, other MMS or BLM officials, auditors of the General Accounting Office, or other persons authorized to receive such documents, or

shall be submitted to MMS within a reasonable period of time, as determined by MMS. Any oral sales arrangement negotiated by the lessee must be placed in written form and retained by the lessee. Records shall be retained in accordance with 30 CFR part 212.

Subpart B—Oil, Gas, and OCS Sulfur, General [Reserved]

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

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PART 208—SALE OF FEDERAL ROYALTY OIL

Subpart A—General Provisons

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AUTHORITY: 5 U.S.C. 301 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq.*; 30 U.S.C. 1701 *et seq.*; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.; 43 U.S.C. 1331 et seq.* and 43 U.S.C. 1801 *et seq.*

SOURCE: 52 FR 41913, Oct. 30, 1987, unless otherwise noted.

Subpart A—General Provisions

§208.1 General.

The regulations in this part govern the sale of royalty oil by the United States to eligible refiners. The regulations apply to royalty oil from leases on Federal lands onshore and on the Outer Continental Shelf (OCS).

§208.2 Definitions.

Allotment means the quantity of royalty oil that DOI determines is available to each eligible refiner that has applied for a portion of the total volume of royalty oil offered in a given royalty oil sale.

Application means the formal written request to DOI on Form MMS–4070 by an eligible refiner interested in purchasing a quantity of royalty oil from the approximate volume announced by DOI in a given ''Notice of Availability of Royalty Oil.''

Area or *Region* means the geographic territory having Federal oil and gas leases over which MMS has jurisdiction, unless the context in which those words are used indicates that a different meaning is intended.

Delivery point means the point where the lessor, in accordance with lease terms, directs the lessee to deliver royalty oil to a purchaser. Title to the royalty oil, or to the quantity thereof in a commingled stream, passes from the Federal Government to the purchaser at this designated point, which is specified in the royalty oil contract. For onshore leases, the delivery point will be on or adjacent to the lease, except as provided in §208.8(a) of this part. In instances where an onshore delivery point is designated for offshore royalty oil, such point generally will be the first onshore point where the price of the oil, including transportation costs, can be determined and where the purchaser can either exchange or take delivery of the oil. The Government does not guarantee physical access to the oil at such point.

Director means the Director of MMS, who is responsible for its overall direction, or his or her delegate(s).

DOI means the Department of the Interior, including the Secretary or his or her delegate(s).

Eligible refiner means a refiner of crude oil that meets the following criteria for eligibility to purchase royalty oil:

(1) For the purchase of royalty oil from onshore leases, it means a refiner that qualifies as a small and independent refiner as those terms are defined in sections 3(3) and 3(4) of the Emergency Petroleum Allocation Act, 15 U.S.C. 751 *et seq.*, except that the time period for determination contained in section 3(3)(A) would be the calendar quarter immediately preceding the date of the applicable ''Notice of Availability of Royalty Oil.'' A refiner that, together with all persons controlled by, in control of, under common control with, or otherwise affiliated with the refiner, inputs a volume of domestic crude oil from its own production exceeding 30 percent of its total refinery input of crude oil is ineligible to participate in royalty oil sales under this part. Crude oil received in exchange for such refiner's own production is considered to be that refiner's own production for purposes of this section.

(2) For the purchase of royalty oil from leases on the OCS, it means a refiner that qualifies as a small business enterprise under the rules of the Small Business Administration (13 CFR part 121).

Entitlement means the volume of royalty oil from the Federal Government's share of production from a Federal lease which a purchaser is entitled to receive under a royalty oil contract.

Exchange agreement means a written agreement between the purchaser and another person for the exchange of royalty oil purchased under this part for other oil on a volume or equivalent value basis.

Fair market value means the value of oil—(1) Computed at a unit price equivalent to the average unit price at which oil was sold pursuant to a lease during the period for which any royalty or net profit share is accrued or reserved to the United States pursuant to such lease, or

(2) If there were no such sales, or if the Secretary finds that there were an insufficient number of such sales to equitably determine such value, computed at the average unit price at which oil was sold pursuant to other

leases in the same region of the OCS during such period, or

(3) If there were no sales of oil from such region during such period, or if the Secretary finds that there are an insufficient number of such sales to equitably determine such value, at an appropriate price determined by the Secretary.

Federal lease means a contractual agreement with the Federal Government which authorizes the exploration, development, and production of oil and gas on Federal lands onshore or on the OCS.

Interim sale means a sale conducted as a result of substantial additional royalty oil becoming available in a specific area prior to the scheduled expiration date of royalty oil contracts in effect for that area.

Lessee means any person to whom the United States issues a lease, or any person who has been assigned an obligation to make royalty or other payments required by the lease.

MMS means the Minerals Management Service of the Department of the Interior.

Notice of Availability of Royalty Oil means a notice published by DOI in the FEDERAL REGISTER (and in other printed media when appropriate, such as a newspaper or magazine of general or specialized circulation) to advise interested parties of the availability of royalty oil for purchase by eligible refiners and the approximate volume of royalty oil available to the applicants.

OCS means the Outer Continental Shelf, as defined in 43 U.S.C. 1331(a).

OCSLA means the Outer Continental Shelf Lands Act (43 U.S.C. 1331 et seq., as amended by 43 U.S.C. 1801 et seq.).

Oil means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and is marketed or used as such. Condensate recovered in lease separators or field facilities is considered to be oil.

Operator means any person, including a lessee, who has control of or who manages operations on an oil and gas lease site on Federal onshore lands or on the OCS.

Payor means any person responsible for reporting royalties from a Federal lease or leases on Form MMS–2014.

Person means any individual, firm, corporation, association, partnership, consortium, or joint venture.

Preference eligible refiner means an eligible refiner with at least one operating refinery which is located within the area designated as the preference eligible area in the ''Notice of Availability of Royalty Oil.'' A refiner may be deemed to be a preference eligible refiner if it owns a refinery located in the preference eligible area which is not operational if the refiner meets the requirements of § 208.7(g) of this part.

Purchaser means anyone who acquires royalty oil sold by DOI under the Federal Government's Royalty-in-Kind (RIK) Program and who has a contractual obligation under an agreement to purchase royalty oil.

Reallocation means an offering of royalty oil previously allocated in a specific sale but subsequently turned back to MMS. A reallocation would only be made if substantial amounts of royalty oil are turned back.

Refined petroleum product means gasoline, kerosene, distillates (including Number 2 fuel oil), refined lubricating oils, or diesel fuel.

Royalty oil means that amount of oil that DOI takes in kind in partial or full satisfaction of a lessee's royalty or net profit share obligations as determined by whatever lease interest the lessee holds under an applicable mineral leasing law.

Secretary means the Secretary of the Department of the Interior or his/her delegate(s).

Section 6 lease means an oil and gas lease originally issued by any State and currently maintained in effect pursuant to section 6 of the OCSLA.

Section 8 lease means an oil and gas lease originally issued by the United States pursuant to section 8 of the OCSLA.

[52 FR 41913, Oct. 30, 1987; 52 FR 45528, Nov. 30, 1987; 58 FR 64901, Dec. 10, 1993]

§ 208.3 Information collection.

The information collection requirements contained in this part have been approved by OMB under 44 U.S.C. 3501

et seq. The form, filing date, and approved OMB clearance number are identified in 30 CFR 210.10.

[58 FR 64901, Dec. 10, 1993]

§208.4 Royalty oil sales to eligible refiners.

(a) *Determination to take royalty oil in kind.* The Secretary may evaluate crude oil market conditions from time to time. The evaluation will include, among other things, the availability of crude oil and the crude oil requirements of the Federal Government, primarily those requirements concerning matters of national interest and defense. The Secretary will review these items and will determine whether eligible refiners have access to adequate supplies of crude oil and whether such oil is available to eligible refiners at equitable prices. Such determinations may be made on a regional basis. The determination by the Secretary shall be published in the FEDERAL REGISTER concurrent with or included in the ''Notice of Availability of Royalty Oil'' required by 30 CFR 208.5.

(b) *Sale to eligible refiners.* (1) Upon a determination by the Secretary under paragraph (a) of this section that eligible refiners do not have access to adequate supplies of crude oil at equitable prices, the Secretary, at his or her discretion, may elect to take in kind some or all of the royalty oil accruing to the United States from oil and gas leases on Federal lands onshore and on the OCS. The Secretary may authorize MMS to offer royalty oil for sale to eligible refiners only for use in their refineries and not for resale (other than under an exchange agreement).

(2) All sales of royalty oil from onshore leases will be priced at the royalty value that would have been determined for that oil pursuant to 30 CFR part 206 had the royalties been paid in value rather than taken in kind. All sales of royalty oil from OCS leases will be priced at the fair market value of the oil including associated transportation costs to the designated delivery point, if applicable.

(3) An eligible refiner must have a representative at a sale in order to participate. The Secretary may, at his or her discretion, establish purchase limitations and withhold any royalty oil from any offering.

(4) The MMS will recover the administrative costs of the RIK Program through the collection of administrative fees. The fees will consist of an initial nonrefundable contract fee for each executed contract and a monthly variable charge applied to each lease under contract. The amount of the initial contract fee shall be determined prior to a sale and published in the ''Notice of Availability of Royalty Oil.'' The initial contract fee will be payable in equal installments due at the end of the first and second months of the contract. These contract fees will be applied against the RIK Program's administrative costs, and the remainder of the administrative costs will be recovered through the monthly variable charges per lease, which will be billed and payable concurrently with the monthly actual billings for royalty oil. The rate per lease will be determined by dividing the remaining recoverable administrative costs by the total number of leases under contract. The rate may change depending upon whether total administrative costs change and/or whether the number of leases taken in kind changes from one month to another. In instances where production from a lease is sold on a percentage basis to two or more purchasers, each percentage portion of the lease will be considered a separate lease for purposes of administrative fee determination.

(c) Upon a determination by the Secretary under paragraph (a) of this section that eligible refiners do have access to adequate supplies of crude oil at equitable prices, MMS will not take royalties in kind from oil and gas leases for exclusive sale to such refiners. Such determinations may be made on a regional basis.

(d) *Interim sales.* The MMS generally will not conduct interim sales. However, interim sales may be held at the discretion of the Secretary if substantial addition royalty oil becomes available. The potentially eligible refiners, individually or collectively, must submit documentation demonstrating that

adequate supplies of crude oil at equitable prices are not available for purchase. Although sufficient documentation must be submitted, it is not mandatory for each potentially eligible refiner to participate in a submission of such documentation to be determined eligible. The documentation must be submitted to MMS for a determination as to whether an interim sale is needed.

§ 208.5 Notice of royalty oil sale.

If the Secretary decides to take royalty oil in kind for sale to eligible refiners, MMS will issue a ''Notice of Availability of Royalty Oil'' specifying the manner in which the sale is to be effected, the approximate quantity of royalty oil to be offered, information required in applications, the closing date for the receipt of applications for royalty oil, and other general administrative details concerning the application, allocation, and contract award process for the royalty oil. The Notice will describe generally the terms under which the royalty oil contracts will be awarded and will specify which applicants will be deemed preference eligible refiners in the sale proceedings. The Notice will also contain guidelines for reallocation procedures in the event substantial quantities of royalty oil sold in that specific sale are subsequently turned back to MMS. Only those purchasers that hold ongoing contracts from that specific sale will be allowed to participate in any reallocation, which would be voluntary, and then only if they continue to meet eligibility requirements as set forth in 30 CFR 208.2 and 208.7. If a reallocation is held prior to the effective date of the contracts as specified in the ''Notice of Availability of Royalty Oil'', all eligible refiners that selected a lease or leases in that specific sale would be allowed to participate, pursuant to the procedures in the Notice.

§ 208.6 General application procedures.

(a) To apply for the purchase of royalty oil, an applicant must file a Form MMS–4070 with MMS in accordance with instructions provided in the ''Notice of Availability of Royalty Oil'' and in accordance with any instructions issued by MMS for completion of Form MMS–4070. The applicant will be required to submit a letter of intent from a qualified financial institution stating that it would be granted surety coverage for the royalty oil for which it is applying, or other such proof of surety coverage, as deemed acceptable by MMS. The letter of intent must be submitted with a completed Form MMS–4070.

(b) In addition to any other application requirements specified in the Notice, the following information is required on Form MMS–4070 at the time of application:

(1) Name and address of the applicant, the location of the applicant's refinery or refineries, and disclosure of the applicant's affiliation with any other persons.

(2) The capacity of the applicant's refineries in barrels of crude oil throughput per calendar day and a tabulation for the past 12 months of oil processed for each refinery, identified as to source (from own production or from other sources).

(3) Identification of any Government royalty oil contracts under which the applicant is currently receiving royalty oil.

(4) Identification of the locations (area/region and State) where the applicant proposes to purchase royalty oil, the volume of oil requested, and the specific refineries in which the oil will be refined.

(5) A certification from the applicant that it is an eligible refiner for the purchase of Government royalty oil, as defined in § 208.2 of this part.

[52 FR 41913, Oct. 30, 1987, as amended at 58 FR 64901, Dec. 10, 1993]

§ 208.7 Determination of eligibility.

(a) The MMS will examine each application and may request additional information if the information in the application is inadequate. An application received after the close of the application period will be rejected. If additional information is requested by MMS, it must be received by the time specified or the application will be rejected.

(b) After the close of the application period and the receipt of any additional

requested information, MMS will determine which applicants may participate in the royalty oil sale and the quantity of royalty oil which each applicant is authorized to purchase.

(c) When applications are filed by two or more eligible refiners for the same royalty oil, the oil will be allocated among such applicants on an equitable basis as determined by MMS. Preference eligible refiners will be given priority in the allocation procedures in sales and subsequent reallocations of royalty oil.

(d) No eligible refiner shall be awarded contracts for volumes of royalty oil that, when added to volumes of other Federal royalty oil being received, are in excess of 60 percent of the combined refinery capacity of that refiner.

(e) The MMS may exclude any section 6 lease from a royalty oil sale.

(f) If two or more eligible refiners are related through common ownership or control or otherwise affiliated, only one of them shall be entitled to an allotment of royalty oil from a specific sale.

(g) Any applicant whose refinery is not in operation during the 60-day period prior to the date of the royalty oil sale shall not be entitled to participate in the sale unless such applicant self-certifies and demonstrates to the satisfaction of MMS that it will begin operations by the first month in which oil becomes available under a royalty oil contract. If operations do not begin by that month, MMS will terminate the contract.

(h) Applicants or purchasers that have delinquent balances with MMS as of the date of a royalty oil sale or subsequent reallocation will not be allowed to participate in that sale or reallocation. If a person which is controlled by, in control of, under common control with, or otherwise affiliated with an applicant or purchaser has such delinquent balances, the applicant or purchaser will not be allowed to participate in a royalty oil sale or reallocation. To the extent a purchaser or affiliated person has appealed a billing and posted a surety instrument in accordance with the contract terms and applicable MMS regulations or other law, the balance shall not be considered delinquent.

(i) A purchaser must meet the eligibility criteria on the date of contract issuance. However, a change in a purchaser's eligibility status during the term of the contract will not affect the purchaser's right to continue that contract until its term expires, including any extensions thereof.

[52 FR 41913, Oct. 30, 1987, as amended at 58 FR 64901, Dec. 10, 1993]

§208.8 Transportation and delivery.

(a) The lessee shall deliver royalty oil from onshore leases to the purchaser at a point on or adjacent to the lease pursuant to the terms of the lease. If the purchaser does not have access to its onshore royalty oil entitlement at facilities on or adjacent to the lease, the operator of the lease must designate an alternate delivery point at no additional cost to the purchaser or the Government. The purchaser must have physical access to the oil at the alternate delivery point and such point must be approved by MMS.

(b) The lessee shall deliver royalty oil from section 8 offshore leases issued after September 1969 at a delivery point to be designated by MMS. The lessee shall deliver royalty oil from section 8 offshore leases issued before October 1969 or from section 6 leases at a delivery point to be designated by the lessee. If the delivery point is on or immediately adjacent to the lease, the royalty oil will be delivered without cost to the Federal Government as an undivided portion of production in marketable condition at pipeline connections or other facilities provided by the lessee, unless other arrangements are approved by MMS. If the delivery point is not on or immediately adjacent to the lease, MMS will reimburse the lessee for the reasonable cost of transportation to such point in an amount not to exceed the transportation allowance determined pursuant to 30 CFR part 206. The MMS will include such transportation costs in the price charged for the oil taken in kind to reflect the value of the oil at the delivery point. Arrangements for delivery of the royalty oil from, or exchange of the oil at, the delivery point, and related transportation costs, are the responsibility of the purchaser of the royalty

oil. In addition, quality differentials between the royalty oil to which a purchaser is entitled and the oil which is made available at the delivery point are matters to be resolved between the purchaser and the operator.

(c) When the purchaser has physical access to the royalty oil at the delivery point, the lessee shall deliver such oil in marketable condition at pipeline connections or other facilities designated by MMS. If the lessee is unable to provide the royalty portion of actual production from the lease, the lessee must provide crude oil to the purchaser which is equivalent in volume or value to the royalty oil to which the purchaser is entitled. The lessee will deliver the royalty oil to the purchaser during normal operating hours and in reasonable quantities and intervals. The lessee will make available and the purchaser will accept delivery of the royalty oil entitlement no later than the last day of the calendar month immediately following the calendar month in which the oil was produced. Failure to accept deliveries shall constitute grounds for the termination of the contract.

(d) Upon termination of deliveries under a royalty oil contract, the transportation allowance and delivery point designation authorized by this section no longer will remain in effect.

§ 208.9 Agreements.

(a) A purchaser must submit to MMS two copies of any written third-party agreements, or two copies of a full written explanation of any oral third-party agreements, relating to the method and costs of delivery of royalty oil, or crude oil exchanged for the royalty oil, from the point of delivery under the contract to the purchaser's refinery. In addition, the purchaser must submit copies of agreements pertaining to quality differentials which may occur between leases and delivery points.

(b) A purchaser may not sell royalty oil which it purchases pursuant to this part except for purposes of an exchange for other crude oil on a volume or equivalent value basis.

(c) Royalty oil purchased under this part, or crude oil received in exchange for such royalty oil, must be processed into refined petroleum products in the purchaser's refinery.

§ 208.10 Notices.

(a) The MMS shall notify each operator, by certified mail, of the Secretary's decision to take royalty oil in kind. This notice shall be mailed at least 45 days in advance of the effective date of delivery and will specify delivery points for offshore oil for OCS leases issued after September 1969.

(b) Deliveries of royalty oil may be partially terminated only with the written approval of the Director, MMS.

(c) Before terminating the delivery of royalty oil taken in kind, MMS, if possible, will notify each operator by certified mail of the change in requirements at least 30 days in advance of the effective date.

(d) After MMS notification that royalty oil will be taken in kind, the operator shall be responsible for notifying each working interest on the Federal lease. As soon as practicable after the date of each royalty oil sale, MMS will publish in the FEDERAL REGISTER a notice of the leases from which royalty oil will be taken, the purchasers of the royalty oil, and the leases from which royalty oil deliveries will be discontinued on terminated contracts.

(e) A purchaser cannot transfer, assign, or sell its rights or interest in a royalty oil contract without written approval of the Director, MMS. If the purchaser changes ownership or its assets are sold or liquidated for any reason, it cannot transfer, assign, or sell its rights or interest in the royalty oil contract without written approval of the Director, MMS. Without express written consent from MMS for a change in ownership, the royalty oil contract shall be terminated. The successor company must meet the definition of an eligible refiner in § 208.2 of this part for MMS to consider assignment of the royalty oil contract.

§ 208.11 Surety requirements.

(a) The eligible purchaser, prior to execution of the contract, shall furnish an ''MMS-specified surety instrument,'' in an amount equal to the estimated value of royalty oil that could be taken by the purchaser in a 99-day period, plus related administrative

charges. The MMS may require the purchaser to increase the amount of the surety instrument when necessary to protect the Government's interest or may allow the purchaser to decrease the amount of the surety instrument where necessary to further the purposes of the Royalty-in-Kind Program.

(b) If a letter of credit is furnished as the surety instrument, it must be effective for a 9-month period beginning the first day the royalty oil contract is effective, with a clause providing for automatic renewal monthly for a new 9-month period. The purchaser or its surety company may elect not to renew the letter of credit at any monthly anniversary date, but must notify MMS of its intent not to renew at least 30 days prior to the anniversary date. The MMS may grant the purchaser 45 days to obtain a new surety instrument. If no replacement surety instrument is provided, MMS will terminate the contract effective at least 6 months prior to the expiration date of the letter of credit. Notwithstanding the above provisions, the letter of credit also may contain a clause providing for automatic termination 6 months after the royalty oil contract terminates. If a certificate of deposit is furnished as the surety instrument, it must be effective for the life of the contract plus 6 months after the royalty oil contract terminates.

(c) For the purposes of this section, an ''MMS-specified surety instrument'' means either: an MMS-specified surety bond, an MMS-specified irrevocable letter of credit, or a financial institution book-entry certificate of deposit.

(d) The ''MMS-specified surety instrument'' shall be in a form specified by MMS instructions or approved by MMS. A bond must be issued by a qualified surety company that has been approved by the Department of the Treasury. An irrevocable letter of credit or a certificate of deposit must be from a financial institution acceptable to MMS. The MMS will use a bank rating service to determine whether a financial institution has an acceptable rating to provide a surety instrument deemed adequate to indemnify the Government from loss or damage.

(e) All surety instruments must be in a form acceptable to MMS and must include such other specific requirements as MMS may require adequately to protect the Government's interests.

[58 FR 64901, Dec. 10, 1993]

§ 208.12 Payment requirements.

(a) All payments to MMS by a purchaser of royalty oil will be due on the date and at the location specified in the contract, or, if there is no contractual provision, as specified by MMS. The purchaser shall tender all payments to MMS in accordance with 30 CFR 218.51. Payments made by a payor pursuant to the requirements of paragraph (b) of this section and § 208.13 also shall be tendered in accordance with 30 CFR 218.51.

(b)(1) Payments from a purchaser of royalty oil not received by MMS when due, or that portion of the payment less than the full amount due, will be subject to a late payment charge equivalent to an interest assessment on the amount past due for the number of days that the payment is late at the underpayment rate applicable under section 6621 of the Internal Revenue Code of 1954.

(2) The MMS may assess interest to a payor for any underpayments which are the result of the payor's late or underreporting, or for adjustments reported by the payor, or made as a result of audit, reconciliation, or other procedures. The interest for late payment and underpayment will be assessed pursuant to 30 CFR 218.54.

(c) If payment for royalty oil is not received by the due date specified in the contract, a notice of nonreceipt will be sent to the purchaser by certified mail. If payment is not received by MMS within 15 days from the date of such notice, MMS may cancel the contract and collect under the MMS-specified surety instrument. See § 208.11.

(d) If the purchaser disagrees with the amount of payment due, it must pay the amount due as computed by MMS, unless the purchaser appeals the amount and posts an MMS-specified surety instrument pursuant to the provisions of 30 CFR part 243. The MMS may, at its discretion, waive the appeal surety requirements if it determines that the contract surety instrument is

sufficient protection for an amount under appeal.

[52 FR 41913, Oct. 30, 1987, as amended at 64901, Dec. 10, 1993]

§ 208.13 Reporting requirements.

If MMS underbills a purchaser under a royalty oil contract because of a payor's underreporting or failure to report on Form MMS–2014 pursuant to 30 CFR 210.52, the payor will be liable for payment of such underbilled amounts plus interest if they are unrecoverable from the purchaser or the surety instrument related to the contract.

[58 FR 64902, Dec. 10, 1993]

§ 208.14 Civil and criminal penalties.

Failure to abide by the regulations in this part may result in civil and criminal penalties being levied on that person as specified in sections 109 and 110 of the Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. 1719–20, and regulations at 30 CFR part 241. Civil penalties applicable under the OCSLA and the Mineral Leasing Act of 1920 may also be imposed.

§ 208.15 Audits.

Audits of the accounts and books of lessees, operators, payors, and/or purchasers of royalty oil taken in kind may be made annually or at such other times as may be directed by MMS. Such audits will be for the purpose of determining compliance with applicable statutes, regulations, and royalty oil contracts.

§ 208.16 Appeals.

Except as provided in § 208.12(d) of this part, orders or decisions issued under the regulations in this part may be appealed as provided in 30 CFR parts 243 and 290.

§ 208.17 Suspensions for national emergencies.

The Secretary of the Department of the Interior, upon a recommendation by the Secretary of Defense or the Secretary of Energy and with the approval of the President, may suspend operations under these regulations and suspend royalty oil contracts during a national emergency declared by the Congress or the President.

PART 210—FORMS AND REPORTS

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Subpart I—OCS Sulfur [Reserved]

AUTHORITY: 5 U.S.C. 301 *et seq.;* 25 U.S.C. 396 *et seq.;* 25 U.S.C. 396a *et seq.;* 25 U.S.C. 2101 *et seq.;* 30 U.S.C. 181 *et seq.;* 30 U.S.C. 351 *et seq.;* 30 U.S.C. 1001 *et seq.;* 30 U.S.C. 1701 *et seq.;* 31 U.S.C. 3716 *et seq.;* 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.;* 43 U.S.C. 1331 *et seq.;* and 43 U.S.C. 1801 *et seq.*

Subpart A—General Provisions

§ 210.10 Information collection.

(a) *Forms*—This section identifies required MMS Royalty Management Program forms for reporting sales and royalties, production information, claiming a processing or transportation allowance, or claiming a reward for providing original information. The information collection requirements associated with the forms identified in this section have been approved by OMB under 44 U.S.C. 3501 et seq. The forms, filing dates, and approved OMB clearance numbers are summarized below:

Form No., name, and filing date	OMB No.
MMS–2014—Report of Sales and Royalty Remittance—Due by the end of first month following production month for royalty payment and for rentals no later than anniversary date of the lease	1010–0022
MMS–3160—Monthly Report of Operations—Due by the 15th day of the second month following the production month	1010–0040
MMS–4025—Oil and Gas Payor Information Form—Due 30 days after issuance of a new lease or change to an existing lease	1010–0033
MMS–4030—Solid Minerals Payor Information Form—Due 30 days after issuance of a new lease or change to an existing account established by an earlier form	1010–0064
MMS–4051—Facility and Measurement Information Form and Supplement—Due at the request of MMS during the initial conversion of the facility and measurement device operators	1010–0040
MMS–4053—First Purchaser Report—Due at the request of MMS	1010–0040
MMS–4054—Oil and Gas Operations Report—Due by the 15th day of the second month following the production month	1010–0040
MMS–4055—Gas Analysis Report—Due by the 15th day of the second month following the production month	1010–0040
MMS–4056—Gas Plant Operations Report—Due by the 15th day of the second month following the production month	1010–0040
MMS–4058—Production Allocation Schedule Report—Due by the 15th day of the second month following the production month	1010–0040
MMS–4059—Solid Minerals Operation Report—Due by the 15th day of the second month following the production month	1010–0063
MMS–4060—Solid Minerals Facility Report—Due by the 15th day of the second month following the production month	1010–0063
MMS–4070—Application of the Purchase of Royalty Oil—Due prior to the date of sale in accordance with the instructions in the Notice of Availability of Royalty Oil	1010–0042
MMS–4109—Gas Processing Allowance Summary Report—Initial report due within 3 months following the last day of the month for which an allowance is first claimed, unless a longer period is approved by MMS	1010–0075
MMS–4110—Oil Transportation Allowance Report—Initial report due within 3 months following the last day of the month for which an allowance is first claimed, unless a longer period is approved by MMS	1010–0061
MMS–4280—Application for Reward for Original Information—Due when a reward is claimed for information provided which may lead to the recovery of royalty or other payments owed to the United States	1010–0076
MMS–4292—Coal Washing Allowance Report—Due prior to or at the same time that the allowance is first reported on Form MMS–2014 and annually thereafter if the allowance does not change	1010–0074
MMS–4293—Coal Transportation Allowance Report—Due prior to or at the same time that the allowance is first reported on Form MMS–2014 and annually thereafter if the allowance does not change	1010–0074
MMS–4295—Gas Transportation Allowance Report—Initial report due within 3 months following the last day of month for which an allowance is first claimed unless a longer period is approved by MMS	1010–0075
MMS–4377—Stripper Royalty Rate Reduction Notification—Due for each 12-month qualifying period that a reduced royalty rate is granted by the Bureau of Land Management	1010–0090

The information required on the forms identified in the table above is being collected by the Department of the Interior to meet its congressionally mandated accounting and auditing responsibilities relating to Federal and Indian mineral royalty management. The purpose of the forms and the estimated public reporting burden associated with each form are described in paragraph (c) of this section. With the exception of Forms MMS–4109, MMS–4110, MMS–4280, MMS–4292, MMS–4293, and MMS–4295, the forms are mandatory. Information on Forms MMS–4109, MMS–4110, MMS–4292, MMS–4293, and MMS–4295 is required to receive a benefit. Information required on Form MMS–4280 must be provided voluntarily to claim a reward. Information collected relative to production, royalties, and other payments due the Government from activities on leased Federal or Indian land is authorized by the Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. 1701 et seq. for oil and gas production, and by 30 U.S.C. 189, 30 U.S.C. 359, and 30 U.S.C. 396d for solid mineral production.

(b) *MMS mailing addresses*—This paragraph identifies the MMS address(es) to be used for requesting forms and/or for mailing completed forms to MMS.

(1) Requests for Forms MMS–2014 or MMS–4070 should be addressed to the Minerals Management Service, Royalty Management Program, P.O. Box 5760, Denver, Colorado 80217–5760. The completed Form MMS–2014 should be mailed to the Minerals Management Service, Royalty Management Program, P.O. Box 5810, Denver, Colorado 80217–5810. The address to which a completed Form MMS–4070 should be mailed will be identified in a FEDERAL REGISTER Notice of Availability of Royalty Oil. (See 30 CFR 208.5.)

(2) Requests for Forms MMS–4025 or MMS–4030 should be addressed to the Minerals Management Service, Royalty Management Program, P.O. Box 5760, Denver, Colorado 80217–5760. The completed forms should be mailed to the same address.

(3) Requests for Forms MMS–3160, MMS–4051, MMS–4052, MMS–4053, MMS–4054, MMS–4055, MMS–4056, MMS–4057, MMS–4058, MMS–4059, MMS–4060, or MMS–4061 should be addressed to the Minerals Management Service, Royalty Management Program, P.O. Box 17110, Denver, Colorado 80217–0110. The completed forms should be mailed to the same address.

(4) Requests for processing or transportation allowance forms (Forms MMS–4109, MMS–4110, MMS–4292, MMS–4293, or MMS–4295) should be addressed to the Minerals Management Service, Royalty Management Program, P.O. Box 25165, Denver, Colorado 80225–0165. The completed allowance forms should be mailed to the Minerals Management Service, Royalty Management Program, P.O. Box 5200, Denver, Colorado 80217–5200.

(5) Requests for Form MMS–4280 should be addressed to the Minerals Management Service, Royalty Management Program, P.O. Box 25165, Denver, Colorado 80225–0165. The completed form should be mailed to the same address. (See 30 CFR 218.57(b)).

(6) Reports delivered to MMS by special couriers or overnight mail shall be addressed as follows: Minerals Management Service, Royalty Management Program, Building 85, Denver Federal Center, room A–212, Denver, Colorado 80225.

(c) *Purpose of forms and estimated public reporting burden*—This paragraph describes the purpose of the information being collected and the estimated public reporting burden associated with the OMB approved forms identified in paragraph (a) of this section.

(1) *MMS–2014*—Used monthly to report lease-related transactions essential for royalty management to determine the correct royalty amount due, reconcile or audit data, and distribute payments to appropriate accounts. Public reporting burden is estimated to average 7 minutes to complete each line item on the form, including the time necessary to assemble data, calculate value and royalty, and enter data on the form. Companies with equipment enabling them to report using tape media may average 3 minutes to complete each line item on the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0022.

(2) *MMS–3160*—Used by onshore oil and gas lease operators to report monthly oil and gas production to MMS. Public reporting burden is estimated to average 15 minutes per form including time spent reading instructions, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(3) *MMS–4025*—This form is used to establish a data base of payor accounts for oil and gas leases on Federal or Indian lands, reporting changes in payor accounts, and notifying MMS of the products on which royalties will be paid. Public reporting burden is estimated to average 30 minutes per form, including time spent reading instructions, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0033.

(4) *MMS–4030*—This form is used to establish a data base of payor accounts for solid mineral leases on Federal or Indian lands, reporting any changes to the accounts, and identifying the type of mine and product produced. Public reporting burden is estimated to average 30 minutes per form, including

time spent reading instructions, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0064.

(5) *MMS–4051*—Used to establish a reference data base identifying the facilities where oil and gas production is stored or processed and the metering points where production is measured for sale or transfer. Public reporting burden is estimated to average 30 minutes per form for facility operators to review and update the data base. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(6) *MMS–4053*—Designed as an audit tool to be used to confirm sales data. Public reporting burden is estimated to average 30 minutes per form, including time spent reading instructions, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(7) *MMS–4054*—This three-part form identifies all oil and gas lease production from Federal and Indian lands. The MMS uses information from this form to track oil and gas from the point of production to the point of first sale or other disposition. Respondents will generally not use all three parts of the form. Public reporting burden is estimated to average 30 minutes per month, including time gathering data, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(8) *MMS–4055*—This report identifies the separate components of natural gas production. It is submitted quarterly or semiannually by lease operators when gas production is processed before royalty value has been determined. Public reporting burden is estimated to average 15 minutes per form including time required gathering data, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(9) *MMS–4056*—Submitted monthly by gas plant operators to identify components and disposition of natural gas from Federal and Indian leases. Public reporting burden is estimated to average 30 minutes per form, including time required gathering data, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(10) *MMS–4058*—Submitted monthly by operators of the facilities and measurement points where production from a Federal or Indian lease is commingled with production from other sources before it is measured for royalty determination. The data reported is used to determine whether sales reported by lessees are reasonable. Public reporting burden is estimated to average 15 minutes per form, including time required gathering data, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0040.

(11) *MMS–4059*—This form consists of parts A and B. It is submitted by all operators of Federal or Indian solid mineral leases on a schedule established on the lease. Public reporting burden is estimated to range from 30 minutes per form for the majority of operators who submit only part A to report production and disposition of raw materials, to 1.25 hours for operators submitting both parts A and B to report sales of mine production from a facility beyond the mine site. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0063.

(12) *MMS–4060*—Submitted by operators of secondary processing or remote storage facilities that handle solid mineral production on which royalties have not been determined. The form is usually submitted monthly and requires 1 to 2 hours to complete depending on the processes, inventory, and production disposition to be reported. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0063.

(13) *MMS–4070*—After publication in the Federal Register of a Notice of Availability of Royalty Oil, refiners interested in the purchase of royalty oil should submit their applications using this form. The information collected is used by MMS to determine if the applicant meets eligibility requirements to

contract to purchase the oil. Public reporting burden is estimated to average 1 hour per form, including time required gathering data, completing, and mailing the form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0042.

(14) *MMS–4109*—Used to claim an allowance for the reasonable, actual costs of removing hydrocarbon and nonhydrocarbon elements or compounds from the gas streams. Public reporting burden varies depending on the type of contract involved. Under an arm's-length contract, burden is estimated to average 1 hour for the submission of page 1 and schedule 1 of the form requiring the lessee's name and address, payor code, plant name, accounting identification number, product code, and selling arrangement. Nonarm's-length contract claims require completion of all pages of the form including calculations of allowable operating and maintenance costs, overhead, depreciation, and return on undepreciated capital investment. Public reporting burden is estimated to average 10 hours to complete the entire form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0075.

(15) *MMS–4110*—Used to claim an allowance for expenses incurred by a lessee in transporting oil from the lease site to a point remote from the lease where value is determined. Public reporting burden varies depending on the type of contract involved. Under an arm's-length contract, burden is estimated to average 2 hours for the submission of page 1 and schedule 1 of the form requiring the lessee's name and address, payor code, accounting identification number, product code, and selling arrangement. Nonarm's-length contract claims require completion of all pages of the form including calculations of allowable operating and maintenance costs, overhead, depreciation, and return on undepreciated capital investment. Public reporting burden is estimated to average 5 hours to complete the entire form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0061.

(16) *MMS–4280*—This form is used to claim a reward for information leading to the recovery of payments owed to the United States from oil and gas leases on Federal land or the Outer Continental Shelf. Claimants must provide name, address, Social Security number, and a brief description of the violation being reported. Public reporting burden is estimated to average 30 minutes to complete this form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0076.

(17) *MMS–4292*—This form is used to claim an allowance for the reasonable, actual costs incurred to wash coal. Public reporting burden varies depending on the type of contract involved. Under an arm's-length contract, burden is estimated to average 1 hour for the submission of page 1 of the form requiring the lessee's name and address, payor code, accounting identification number, product code, and selling arrangement. Nonarm's-length contract claims require completion of all pages of the form including calculations of allowable operating and maintenance costs, overhead, depreciation, and return on undepreciated capital investment. Public reporting burden is estimated to average 40 hours to complete the entire form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0074.

(18) *MMS–4293*—Used to claim an allowance for the reasonable, actual costs of transporting coal to a sales point or a washing facility remote from the mine or lease. Public reporting burden varies depending on the type of contract involved. Under an arm's-length contract, burden is estimated to average 1 hour for the submission of page 1 of the form requiring the lessee's name and address, payor code, accounting identification number, product code, and selling arrangement. Nonarm's-length contract claims require completion of all pages of the form including calculations of allowable operating and maintenance costs, overhead, depreciation, and return on undepreciated capital investment. Public reporting burden is estimated to average 40 hours to complete the entire form. Comments submitted relative to

this information collection should reference Paperwork Reduction Project 1010–0074.

(19) *MMS–4295*—This form is used to claim an allowance for the reasonable, actual costs of transporting gas from the lease to the point of first sale. Public reporting burden varies depending on the type of contract involved. Under an arm's-length contract, burden is estimated to average 1 hour for the submission of page 1 and schedule 1 of the form requiring the lessee's name and address, payor code, accounting identification number, product code, and selling arrangement. Nonarm's-length contract claims require completion of all pages of the form including calculations of allowable operating and maintenance costs, overhead, depreciation, and return on undepreciated capital investment. Public reporting burden is estimated to average 3 hours to complete the entire form. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0075.

(20) *MMS–4377*—This form must be submitted by operators of stripper oil properties to notify MMS of reduced royalty rates granted by the Bureau of Land Management under 43 CFR 3103.4–1 for each 12-month qualifying period. Reporting burden is estimated to require an average of 30 minutes per form to supply the operator name, lease and agreement numbers, calculated and current royalty rate, and the period covered. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0090.

(d) *Comments on burden estimates.* Send comments regarding the burden estimates or any other aspect of these information collections, including suggestions for reducing burden, to the Information Collection Clearance Officer, Minerals Management Service, 381 Elden Street, Herndon, VA 22070; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project 1010–XXXX, Washington, DC 20503.

[57 FR 41864, Sept. 14, 1992]

Subpart B—Oil, Gas, and OCS Sulfur—General

AUTHORITY: The Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 *et seq.).*

SOURCE: 49 FR 37345, Sept. 21, 1984, unless otherwise noted.

§ 210.50 Required recordkeeping.

Information required by the MMS shall be filed using the forms prescribed in this subpart, which are available from MMS. Records may be maintained in microfilm, microfiche, or other recorded media that is easily reproducible and readable.

§ 210.51 Payor information form.

The Payor Information Form (Form MMS–4025) must be filed for each Federal or Indian lease on which royalties are paid. Where specifically determined by MMS, Form MMS–4025 is also required for all Federal leases on which rent is due. The completed form must be filed by the party who is making the rent or royalty payment (payor) for each revenue source. Form MMS–4025 must be filed no later than 30 days after issuance of a new lease or a modification to an existing lease which changes the paying responsibility on the lease.

§ 210.52 Report of sales and royalty remittance.

A completed Report of Sales and Royalty Remittance (Form MMS–2014) must accompany all payments to MMS for royalties and, where specified, for rents on nonproducing leases. Payors who submit Form MMS–2014 data on magnetic tape will not be required to submit the form itself. Completed Form MMS–2014's (or magnetic tape) for royalty payments including those covering payments by electronic funds transfer, are due by the end of the month following the production month. Where applicable, completed Form MMS–2014's for rental payments are due no later than the anniversary date of the lease. This section does not prohibit payors from making early payments voluntarily.

§ 210.53 Reporting instructions.

(a) Specific guidance on how to prepare and submit required information collection reports and forms to MMS is contained in an MMS ''Oil and Gas Payor Handbook,'' a ''Production Accounting and Auditing System Reporter Handbook,'' and a ''PAAS Onshore Oil and Gas Reporter Handbook.'' The Payor Handbook is available from the Minerals Management Service, Royalty Management Program, P.O. Box 5760, Denver, Colorado 80217–5760. The Reporter Handbooks are available from the Minerals Management Service, Royalty Management Program, P.O. Box 17110, Denver, Colorado 80217–0110.

(b) Royalty payors or production reporters should refer to these handbooks for specific guidance with respect to oil and gas reporting requirements. If additional information is required, the payor or reporter should contact the MMS at the above address. The appropriate telephone numbers are listed in the handbooks.

[51 FR 45882, Dec. 23, 1986, as amended at 53 FR 16412, May 9, 1988; 57 FR 41867, Sept. 14, 1992; 58 FR 64902, Dec. 10, 1993]

§ 210.54 Definitions.

Terms used in this subpart shall have the same meaning as in 30 U.S.C. 1702.

[49 FR 37345, Sept. 21, 1984. Redesignated at 51 FR 45882, Dec. 23, 1986]

§ 210.55 Special forms or reports.

When special forms or reports other than those referred to in the regulations in this part may be necessary, instructions for the filing of such forms or reports will be given by MMS.

[53 FR 1226, Jan. 15, 1988]

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General

SOURCE: 51 FR 15766, Apr. 28, 1986, unless otherwise noted.

§ 210.200 Required recordkeeping.

Information required by the Minerals Management Service (MMS) shall be filed using the forms prescribed in this subpart, copies of which are available from MMS. Instructions on the completion of these forms are provided in the Payor Handbook—Solid Minerals, also available from MMS. Records and supporting data may be maintained in hardcopy, microfilm, microfiche, or other recorded media that is readily available and readable.

§ 210.201 Solid minerals payor information form.

A Solid Minerals Payor Information Form (Form MMS–4030) must be submitted to MMS for each Federal and Indian solid minerals lease on which royalties, rentals or minimum royalties are paid. This form does not change any requirement for a separate approval, if required, by the Department of the Interior. The Form MMS–4030 shall identify the payor of rent, minimum royalty, advance royalty and production royalty, and identify revenue sources and selling arrangements for all lease products. The completed form must be filed by each royalty payor no later than 30 days after MMS provides notice that the payor is converted to the Auditing and Financial System (AFS). After filing the initial form, a new Form MMS–4030 must be filed no later than 30 days after the occurrence of any of the following:

(a) Assignment of all or any part of the lease;

(b) Adoption of a new mining method;

(c) Production of a new product;

(d) A change in a selling arrangement;

(e) Change in royalty rate;

(f) Change of payor; or

(g) Abandonment of a lease.

§ 210.202 Report of sales and royalty remittance—solid minerals.

A completed Report of Sales and Royalty Remittance (Form MMS–2014) must accompany all payments to MMS for rents (other than first year) and royalties for Federal and Indian solid minerals leases. On leases where payment is remitted directly to an Indian tribe or Bureau of Indian Affairs office, the payor also must send a completed

form MMS–2014 to MMS for processing in AFS. The Form MMS–2014 shall identify the payor and the lease subaccounts, contain production, sales, and royalty data, and identify the time period applicable to the data. Completed forms are due at the end of the month following the production or sales period as applicable. Unless the lease terms specify a different royalty payment frequency, all reports and payments are due monthly. If the lease terms do specify a different frequency for payment, the reporting must coincide with the payment. The Form MMS–2014 for rental payments is due no later than the rental payment date specified in the lease terms.

[51 FR 15766, Apr. 28, 1986, as amended at 57 FR 52720, Nov. 5, 1992]

§ 210.203 Special forms and reports.

The MMS may require submission of additional information on special forms or reports. When special forms or reports other than those referred to in this subpart are necessary, instructions for the filing of such forms or reports will be given by MMS. Requests for the submission of such forms will be made in conformity with the requirements of the Paperwork Reduction Act of 1980 and other applicable laws.

§ 210.204 Reporting instructions.

(a) Specific guidance on how to prepare and submit required information collection reports and forms to MMS is contained in an ''MMS Payor Handbook—Solid Minerals'' and a ''Production Accounting and Auditing System Reporter Handbook.'' The Payor Handbook is available from the Minerals Management Service, Royalty Management Program, P.O. Box 5760, Denver, Colorado 80217–5760. The Reporter Handbook is available from the Minerals Management Service, Royalty Management Program, P.O. Box 17110, Denver, Colorado 80217–0110.

(b) Royalty payors or production reporters should refer to these handbooks for specific guidance with respect to solid minerals reporting requirements. If additional information is required, the payor or reporter should contact the MMS at the above address. The appropriate telephone numbers are listed in the handbooks.

[51 FR 45883, Dec. 23, 1986, as amended at 57 FR 41867, Sept. 14, 1992; 58 FR 64902, Dec. 10, 1993]

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources

SOURCE: 56 FR 57286, Nov. 8, 1991, unless otherwise noted.

§ 210.350 Definitions.

Terms used in this subpart shall have the same meaning as in 30 CFR 206.351.

§ 210.351 Required recordkeeping.

Information required by MMS shall be filed using the forms prescribed in this subpart, which are available from MMS. Records may be maintained on microfilm, microfiche, or other recorded media that are easily reproducible and readable. See subpart H of 30 CFR part 212.

§ 210.352 Payor information forms.

The Payor Information Form (Form MMS–4025) must be filed for each Federal lease on which geothermal royalties (including byproduct royalties) are paid. Where specifically determined by MMS, Form MMS–4025 is also required for all Federal leases on which rent is due. The completed form must be filed by the party who is making the rent or royalty payment (payor) for each revenue source. Form MMS–4025 must be filed no later than 30 days after issuance of a new lease or a modification to an existing lease that changes the paying responsibility on the lease. The Form MMS–4025 shall identify the payor of production royalty, and identify revenue sources and selling arrangements for all leased geothermal resources (including byproducts). After filing the initial form, a new Form MMS–4025 must be filed no later than 30 days after the occurrence of any of the following:

(a) Assignment of all or any part of the lease;

(b) Production of new product;

(c) A change in a selling arrangement;

(d) Change in royalty rate;

(e) Change of payor; or

(f) Abandonment of a lease.

§ 210.353 Special forms and reports.

The MMS may require submission of additional information on special forms or reports. When special forms or reports other than those referred to in this subpart are necessary, MMS will give instructions for the filing of such forms or reports. Requests for the submission of such forms will be made in conformity with the requirements of the Paperwork Reduction Act of 1980 and other applicable laws.

§ 210.354 Monthly report of sales and royalty.

A completed Report of Sales and Royalty Remittance (Form MMS–2014) must be submitted each month once sales or utilization of production occur, even though sales may be intermittent, unless otherwise authorized by MMS. This report is due on or before the last day of the month following the month in which production was sold or utilized, together with the royalties due the United States.

§ 210.355 Reporting instructions.

(a) Specific guidance on how to prepare and submit required information collection reports and forms to MMS is contained in an MMS Oil and Gas Payor Handbook which is available from the Minerals Management Service, Royalty Management Program, P.O. Box 5760, Denver, Colorado 80217–5760.

(b) Royalty payors should refer to this handbook for specific guidance with respect to geothermal resources reporting requirements. If additional information is required, the payor should contact the MMS at the above address. The appropriate telephone numbers are listed in the handbook.

[56 FR 57286, Nov. 8, 1991, as amended at 58 FR 64902, Dec. 10, 1993]

Subpart I—OCS Sulfur [Reserved]

PART 212—RECORDS AND FILES MAINTENANCE

Subpart A—General Provisions [Reserved]

Subpart B—Oil, Gas, and OCS Sulphur—General

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212.50 Required recordkeeping and reports.
212.51 Records and files maintenance.
212.52 Definitions.

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals—General

212.200 Maintenance of and access to records.

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources

212.350 Definitions.
212.351 Required recordkeeping and reports.

Subpart I—OCS Sulfur [Reserved]

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

Subpart A—General Provisions [Reserved]

Subpart B—Oil, Gas, and OCS Sulphur—General

§ 212.50 Required recordkeeping and reports.

All records pertaining to offshore and onshore Federal and Indian oil and gas leases shall be maintained by a lessee, operator, revenue payor, or other person for 6 years after the records are generated unless the recordholder is notified, in writing, that records must

be maintained for a longer period. When an audit or investigation is underway, records shall be maintained until the recordholder is released by written notice of the obligation to maintain records.

[49 FR 37345, Sept. 21, 1984]

§ 212.51 Records and files maintenance.

(a) *Records.* Each lessee, operator, revenue payor, or other person shall make and retain accurate and complete records necessary to demonstrate that payments of rentals, royalties, net profit shares, and other payments related to offshore and onshore Federal and Indian oil and gas leases are in compliance with lease terms, regulations, and orders. Records covered by this section include those specified by lease terms, notices and orders, and by the various parts of this chapter. Records also include computer programs, automated files, and supporting systems documentation used to produce automated reports or magnetic tape submitted to the Minerals Management Service (MMS) for use in its Auditing and Financial System (AFS) and Production Accounting and Auditing System (PAAS).

(b) *Period for keeping records.* Lessees, operators, revenue payors, or other persons required to keep records under this section shall maintain and preserve them for 6 years from the day on which the relevant transaction recorded occurred unless the Secretary notifies the record holder of an audit or investigation involving the records and that they must be maintained for a longer period. When an audit or investigation is underway, records shall be maintained until the recordholder is released in writing from the obligation to maintain the records. Lessees, operators, revenue payors, or other persons shall maintain the records generated during the period for which they have paying or operating responsibility on the lease for a period of 6 years.

(c) *Inspection of records.* The lessee, operator, revenue payor, or other person required to keep records shall be responsible for making the records available for inspection. Records shall be provided at a business location of the lessee, operator, revenue payor, or other person during normal business hours upon the request of any officer, employee or other party authorized by the Secretary. Lessees, operators, revenue payors, and other persons will be given a reasonable period of time to produce historical records.

[49 FR 37345, Sept. 21, 1984; 49 FR 40576, Oct. 17, 1984]

§ 212.52 Definitions.

Terms used in this subpart shall have the same meaning as in 30 U.S.C. 1702.

[49 FR 37345, Sept. 21, 1984]

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals—General

§ 212.200 Maintenance of and access to records.

(a) All records pertaining to Federal and Indian solid minerals leases shall be maintained by a lessee, operator, revenue payor, or other person for 6 years after the records are generated unless the record holder is notified, in writing, that records must be maintained for a longer period. When an audit or investigation is underway, records shall be maintained until the record holder is released by written notice of the obligation to maintain records.

(b) The MMS shall have access to all records of the operator/lessee pertaining to compliance to Federal royalties, including, but not limited to:

(1) Qualities and quantities of all products mined, processed, sold, delivered, or used by the operator/lessee.

(2) Prices received for mined or processed products, prices paid for like or similar products, and internal transfer prices.

(3) Costs of mining, processing, handling, and transportation.

[47 FR 33193, July 30, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, and amended at 51 FR 15767, Apr. 28, 1986; 54 FR 1532, Jan. 13, 1989]

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources

SOURCE: 56 FR 57286, Nov. 8, 1991, unless otherwise noted.

§ 212.350 Definitions.

Terms used in this subpart shall have the same meaning as in 30 CFR 206.351.

§ 212.351 Required recordkeeping and reports.

(a) *Records.* Each lessee, operator, revenue payor, or other person shall make and retain accurate and complete records necessary to demonstrate that payments of royalties, rentals, and other amounts due under Federal geothermal leases are in compliance with laws, lease terms, regulations, and orders. Records covered by this section include those specified by lease terms, notices, and orders, and those identified in paragraph (c) of this section. Records also include computer programs, automated files, and supporting systems documentation used to produce automated reports or magnetic tapes submitted to MMS for use in its AFS, or in its Production Accounting and Auditing System.

(b) *Period for keeping records.* All records pertaining to Federal geothermal leases shall be maintained by a lessee, operator, revenue payor, or other person for 6 years after the records are generated unless the recordholder is notified, in writing, before the expiration of that 6-year period that records must be maintained for a longer period for purposes of audit or investigation. When an audit or investigation is underway, records shall be maintained until the recordholder is released by written notice of the obligation to maintain records.

(c) *Access to records.* The Associate Director for Royalty Management shall have access to all records in the possession of the lessee, operator, revenue payor, or other person pertaining to compliance with royalty obligations under Federal geothermal leases (regardless of whether such records were generated more than 6 years before a request or order to produce them and they otherwise were not disposed of), including, but not limited to:

(1) Qualities and quantities of all products extracted, processed, sold, delivered, or used by the operator/lessee;

(2) Prices received for products, prices paid for like or similar products, and internal transfer prices; and

(3) Costs of extraction, power generation, electrical transmission, and by-product transportation.

(d) *Inspection of Records.* The lessee, operator, revenue payor, or other person required to keep records shall be responsible for making the records available for inspection. Records shall be made available at a business location of the lessee, operator, revenue payor, or other person during normal business hours upon the request of any officer, employee, or other party authorized by the Secretary. Lessees, operators, revenue payors, and other persons will be given a reasonable period of time to produce records.

Subpart I—OCS Sulfur [Reserved]

PART 215—ACCOUNTING AND AUDITING STANDARDS [RESERVED]

PART 216—PRODUCTION ACCOUNTING

Subpart A—General Provisions

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Subpart B—Oil and Gas, General

216.50 Monthly report of operations.
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Subpart C—Oil and Gas, Onshore [Reserved]

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Subpart E—Solid Minerals, General

216.200 [Reserved]
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Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—Indian Land [Reserved]

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.*

SOURCE: 51 FR 8175, Mar. 7, 1986, unless otherwise noted.

Subpart A—General Provisions

§216.1 Purpose.

The purpose of this part is to ensure that the Federal Government receives proper information regarding energy and mineral resources removed from Federal and Indian leases and federally approved agreements, including the Outer Continental Shelf (OCS).

§216.2 Scope.

This part governs the reporting of oil, gas, and solid minerals operations information on Federal and Indian leases or federally-approved agreements including leases or agreements on the OCS. This part also governs the reporting of other operational information associated with production from Federal and Indian leases or federally-approved agreements when such operations occur prior to the point of sale or royalty determination, whichever is applicable. Reporters are required to submit certain production reports to MMS as set forth in this part.

[58 FR 45254, Aug. 27, 1993]

§216.6 Definitions.

For purposes of this part:

Agreement means a binding arrangement between two or more parties purporting to the act of agreeing or of coming to a mutual arrangement that is accepted by all parties to a transaction (e.g., communitizations, unitization, gas storage, or compensatory royalty agreements.).

Alaska Native Corporation means a corporation created pursuant to the provisions of the Alaska Native Claims Settlement Act (43 U.S.C. 1601 *et seq.*).

Approved mining plan as used in this part means an approved resource recovery and protection plan (43 CFR 3480.5) or approved mining plan (43 CFR 3572.1).

Associate Director means the Associate Director for Royalty Management of the MMS.

Facility means a structure(s) used to store or process Federal or Indian mineral production prior to or at the point of royalty determination.

Federal lease means a lease concerning minerals owned by the United States and includes a lease where an Alaska Native Corporation receives all or part of the royalties accruing from that lease, and the MMS has not waived administration of that lease.

First purchaser means any entity receiving the lease production in a first transfer for value transaction.

Gas means any fluid, either combustible or noncombustible, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely; a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

Indian lease means a lease concerning lands or interest in lands of an Indian Tribe or an Indian allottee, his heirs or devisees, held in trust by the United States or which is subject to Federal restriction against alienation, including mineral resources and mineral estates reserved to an Indian Tribe or an Indian allottee, his heirs or devisees thereto in the conveyance of a surface

or non-mineral estate, except that such term does not include any lands subject to the provisions of section 3 of the Act of June 28, 1906 (34 Stat. 539).

Lease means any contract, profit-share arrangement, joint venture, permit, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, extraction of, or removal of oil, gas, or solid minerals—or the land area covered by that authorization, whichever is covered by the context.

Lessee means any person to whom the United States, an Indian Tribe, or an Indian allottee, issues a lease, or any person who has been assigned an obligation to make royalty or other payments required by the lease.

MMS/RMP means the Royalty Management Program of the Minerals Management Service.

Measurement device means a mechanical or electrical device that is used to measure production of oil, gas, or solid minerals for sales, transfers, and/or royalty determination.

Mine means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of coal or other solid minerals.

Mineral Leasing Law means any Federal law administered by the Secretary authorizing the disposition under lease of oil, gas, or solid minerals.

Oil means any fluid hydrocarbon substance other than gas which is extracted in a fluid state from a reservoir and which exists in a fluid state under the existing temperature and pressure conditions of the reservoir. Oil includes liquefiable hydrocarbon substances such as drip gasoline or other natural condensates recovered in a liquid state from gas.

Operator means any person, including a lessee who has control of, or who manages operations on, any oil and gas or solid minerals lease site on Federal (including the OCS) or Indian lands. ''Operator'' also means any entity engaged in the business of developing, drilling for, producing, transporting, purchasing, selling, or processing oil, gas or solid minerals and/or which has the responsibility of reporting production from a lease or a portion thereof.

Outer Continental Shelf (OCS) has the same meaning as provided in section 2 of the Outer Continental Shelf Lands Act, 43 U.S.C. 1331.

Person means any individual, firm, corporation, association, partnership, consortium or joint venture.

Production Accounting and Auditing System (PAAS) means an integrated system of manual and automated processes for minerals production reporting, accounting, and auditing. Based upon production reports submitted by reporters, the PAAS will track oil, gas, and solid minerals produced from or allocated to Federal and Indian leases, including the OCS, from the source of production to the point of disposition with emphasis on the point of royalty determination, or point of sale, whichever is applicable.

Raw make means natural gas liquids (NGL's) that are extracted from the wet gas stream at a gas plant (e.g., ethane through natural gasoline) which sometimes is transferred to a fractionation plant for further processing.

Reporter means any reporting entity required to submit a PAAS report or form to the MMS.

Secretary means the Secretary of the Interior or his/her designee.

Solid minerals means those minerals including but not limited to coal, potash, sodium, phosphate, sulfur, lead, zinc, copper, silica sands, sand and gravel, and other minerals under mineral leasing laws originating from or allocated to Federal or Indian leases, excluding oil or gas, oil shale, and geothermal resources.

[51 FR 8175, Mar. 7, 1986, as amended at 58 FR 45254, Aug. 27, 1993]

§ 216.10 Information collection.

The information collection requirements contained in this part have been approved by OMB under 44 U.S.C. 3501 et seq. The forms, filing date, and approved OMB clearance numbers are identified in 30 CFR 210.10.

[57 FR 41867, Sept. 14, 1992]

§ 216.15 Reporting instructions.

(a) Specific guidance on how to prepare and submit required information

collection reports and forms to MMS is contained in a ''PAAS Reporter Handbook'' and a ''Paas Onshore Oil and Gas Reporter Handbook.'' The Reporter Handbooks are available from the Minerals Management Service, Royalty Management Program, P.O. Box 17110, Denver, Colorado 80217–0110.

(b) Production reporters should refer to these handbooks for specific guidance with respect to production reporting requirements. If additional information is required, the reporter should contact the MMS at the above address. The telephone number is listed in the handbooks.

[53 FR 16412, May 9, 1988, as amended at 57 FR 41867, Sept. 14, 1992; 58 FR 64903, Dec. 10, 1993]

§ 216.16 Where to report.

(a) All reporting forms listed in this part that are mailed or sent by U.S. Postal Service express mail should be mailed to the Mineral Management Service, Royalty Management Program, P.O. Box 17110, Denver, Colorado 80217–0110.

(b) Reports delivered to MMS by special couriers or overnight mail, except U.S. Postal Service express mail, shall be addressed as follows: Minerals Management Service, Royalty Management Program, Building 85, Denver Federal Center, Denver, Colorado 80225.

(c) A report is considered received when it is delivered to MMS at the addresses specified in paragraphs (a) and (b) of this section. Reports received at the MMS addresses specified in paragraphs (a) and (b) of this section after 4 p.m. mountain time are considered received the following business day.

[56 FR 20127, May 2, 1991, as amended at 57 FR 41867, Sept. 14, 1992; 58 FR 64903, Dec. 10, 1993]

§ 216.20 Applicability.

The requirements of this part shall apply to all oil, gas, and solid mineral operators reporting information on Federal and Indian leases or federally-approved agreements, including leases or agreements on the OCS.

[58 FR 45254, Aug. 27, 1994]

§ 216.21 General obligations of the reporter.

The reporter shall submit accurately, completely and timely, pursuant to the requirements of this part, all information forms and other information required by MMS. Specific guidance on the use of the required forms is contained in the Production Accounting and Auditing System Reporters Handbook. Copies of the handbook are available from the MMS.

§ 216.25 Confidentiality.

(a) Information obtained by MMS pursuant to the rules of this part shall be open for public inspection and copying during regular office hours upon a written request, pursuant to rules at 43 CFR part 2, except that:

(1) Notwithstanding any other provision of this part, information obtained from a reporter under this part relating to a minerals agreement approved pursuant to the Indian Mineral Development Act of 1982, 25 U.S.C. 2101 *et seq.,* the Tribal Leasing Act of 1938 (25 U.S.C. 396a *et seq.*), or the Allotted Indian Mineral Development Act of 1909 (25 U.S.C. 396), shall not be released without the written consent of the Indian Tribe(s) or individual Indian(s) who are parties to the mineral agreement.

(2) Information obtained from a reporter pursuant to this part that constitutes a trade secret and/or commercial or financial information which is privileged or confidential, or other information that may be withheld under the Freedom of Information Act (5 U.S.C. 552(b)), such as geologic and geophysical data concerning wells, shall be available for public inspection in accordance with 43 CFR part 2. When such information is related to Indian lands, consent to release the information must also be obtained from the cognizant Tribe or allottee.

(b) If any geologic and/or geophysical data is submitted under this part, these shall be made available to the public only in accordance with the provisions of 30 CFR 250.3, 250.4 and 252.7, if these relate to an offshore lease, and in accordance with 43 CFR 3162.8 if these relate to an onshore Federal or Indian lease.

§ 216.30 Special forms and reports.

When special forms or reports other than those referred to in the regulations in this part are necessary, instructions for the filing of such forms or reports will be provided by the Associate Director. Such requests will be made in conformity with the requirements of the Paperwork Reduction Act of 1980, and are expected to involve less than 10 respondents annually.

§ 216.40 Assessments for incorrect or late reports and failure to report.

(a) An assessment of an amount not to exceed $10 per day may be charged for each report not received by MMS by the designated due date.

(b) An assessment of an amount not to exceed $10 may be charged for each incorrectly completed report.

(c) For purposes of oil and gas reporting under the PAAS, a report is defined as each line of production information required on the Monthly Report of Operations (Form MMS–3160), Oil and Gas Operations Report (Form MMS–4054), Gas Analysis Report (Form MMS–4055), Gas Plant Operations Report (Form MMS–4056), and Production Allocation Schedule Report (Form MMS–4058).

(d) For purposes of solid minerals reporting under PAAS, a report is defined as each line of production information required on the Solid Minerals Operation Report (Form MMS–4059) and Solid Minerals Facility Report (Form MMS–4060).

(e) The MMS will not make assessments for reporting problems which are beyond the control of the reporter (e.g., reports received late because of bad weather). The reporter shall have the burden of proving that a reporting problem was unavoidable.

(f) An assessment under this section shall not be shared with a State, Indian tribe, Indian allottee, or Alaska Native Corporation.

(g) The amount of the assessment to be imposed pursuant to paragraphs (a) and (b) of this section shall be established periodically by MMS. The assessment amount for each violation will be based on MMS's experience with costs and improper reporting. The MMS will publish a Notice of the assessment amount to be applied in the FEDERAL REGISTER.

[51 FR 8175, Mar. 7, 1986, as amended at 52 FR 27546, July 22, 1987; 53 FR 16412, May 9, 1988; 58 FR 64903, Dec. 10, 1993; 59 FR 38905, Aug. 1, 1994]

Subpart B—Oil and Gas, General

§ 216.50 Monthly report of operations.

(a) Each operator of each onshore Federal or Indian lease or agreement containing at least one well not permanently plugged and abandoned shall file a Monthly Report of Operations (Form MMS–3160) unless production data is authorized to be reported on Form MMS–4054. This requirement does not apply to reporting of operations of gas storage agreements, which must continue to be reported to the appropriate BLM office. A completed Form MMS–3160 shall be filed for each calendar month, beginning with the month in which drilling operations are initiated, on or before the 15th day of the second month following the month being reported until the lease or agreement is terminated, or the last well is approved as permanently plugged or abandoned by BLM and all inventory is disposed of, or until monthly omission of the report is authorized by MMS. The MMS may grant time extensions for filing Form MMS–3160 on a case-by-case basis upon written request to MMS.

(b) Specific and detailed guidance on how to prepare and submit the required production data on the Form MMS–3160 are contained in the MMS *PAAS Onshore Oil and Gas Reporter Handbook*. See § 216.15 of this part.

(c)(1) Operators already reporting onshore lease production data to MMS in accordance with § 216.53 of this part on the effective date of this rule may request to change to the provisions of this section. Any request to change to the requirements of this section must be made by advance written notice to MMS and have MMS approval.

(2) An operator who reports production data to MMS for offshore leases in accordance with § 216.53 of this part may request to report for its onshore leases in accordance with the requirements of that section. Any such request must be made by advance written

notice to MMS and have MMS approval.

(d)(1) Except where disclosure is required by law, information submitted on Form MMS–3160 that MMS classifies as confidential will be protected as such by both MMS and BLM for the period of 1 year. Operators must petition MMS for each lease or agreement to obtain a confidential classification and to extend the classification period beyond 1 year.

(2) Except as provided by statute, information submitted on Form MMS–3160 in regard to Federal leases and Indian leases which are part of a unit containing non-Indian leases is not considered to be confidential.

(3) Except where disclosure is required by law, all information submitted on Form MMS–3160 in regard to Indian leases, other than those included in paragraph (d)(2) of this section, will be considered to be confidential.

(4) Except as provided in this subsection, all other information will be released.

[53 FR 16412, May 9, 1988, as amended at 58 FR 45254, Aug. 27, 1993; 58 FR 64903, Dec. 10, 1993]

§ 216.51 Facility and Measurement Information Form.

A Facility and Measurement Information Form (Form MMS–4051) must be filed for each facility or measurement device which handles production from any Federal or Indian lease, or federally-approved agreement, through the point of first sale or the point of royalty computation, whichever is later. The completed form must be filed by any operator (reporting production on a Form MMS–4054) of an onshore Facility Measurement Point (FMP) that handles production from any Federal or Indian lease or federally-approved agreement prior to, or at the point of royalty determination, or any operator who acquires an onshore FMP that is currently reporting to the PAAS. The report must be filed no later than 30 days after the establishment of a new facility or measurement device, or 30 days after a change is made to an existing facility or measurement device.

[58 FR 45254, Aug. 27, 1993]

§ 216.52 First Purchaser Report.

The First Purchaser Report (Form MMS–4053) must be filed by first purchasers only upon the specific request of MMS.

[51 FR 8175, Mar. 7, 1986. Redesignated at 58 FR 64903, Dec. 10, 1993]

§ 216.53 Oil and Gas Operations Report.

Every operator of an OCS lease or federally-approved offshore agreement and any operator of an onshore Federal or Indian lease or federally-approved agreement that has elected to report production on an Oil and Gas Operations Report (Form MMS–4054) instead of the Form MMS–3160 (see § 216.50(c)(2)) must file a Form MMS–4054 each month as long as there exists at least one well that is not permanently plugged and abandoned. A completed Form MMS–4054 must be filed for each calendar month, beginning with the month in which drilling operations are initiated, on or before the 15th day of the second month following the month being reported, until the lease or agreement is terminated, or the last well is permanently plugged or abandoned and all inventory is disposed of, or until omission of the report is authorized by MMS.

[58 FR 45255, Aug. 27, 1993. Redesignated at 58 FR 64903, Dec. 10, 1993]

§ 216.54 Gas Analysis Report.

Any operator of an OCS lease or federally-approved agreement and, upon request by MMS, any operator of an onshore Federal or Indian lease or federally-approved agreement, from which gas is sold or is transferred for processing prior to the point of royalty computation, must file a Gas Analysis Report (Form MMS–4055) for each sales or transfer meter. The form is due at least twice a year; once in the first 6 months of the calendar year, and once in the last 6 months of the calendar year, but may be submitted monthly, or as specified by the gas sales contract terms, and must be submitted on or before the 15th day of the second month following the end of the reporting period to which the information applies. All reports must be submitted by August 15th for any sales/transfers occurring

in the first 6 months of the calendar year and February 15th of the following year for any sales/transfers occurring in the second 6 months of the calendar year.

[58 FR 45255, Aug. 27, 1993. Redesignated at 58 FR 64903, Dec. 10, 1993]

§ 216.55 Gas Plant Operations Report.

The operator of each gas plant that processes gas that originates from an OCS lease or federally-approved agreement and, upon request by MMS, the operator of a gas plant that processes gas from an onshore Federal or Indian lease or federally-approved agreement, prior to the point of royalty computation, must file a Gas Plant Operations Report (Form MMS–4056) for each calendar month, beginning with the month in which processing of gas is initiated, on or before the 15th day of the second month following the month being reported. The report must show 100 percent of the gas. If a plant no longer processes gas that originated from a Federal or Indian lease, or federally-approved agreement, prior to the point of royalty computation and has not processed such gas for 6 months or more, the operator of the gas plant is not required to file a Gas Plant Operations Report until the plant again produces such gas. The operator of the gas plant must notify MMS, in writing, when such gas has not been processed for 6 months or longer.

[58 FR 45255, Aug. 27, 1993. Redesignated at 58 FR 64903, Dec. 10, 1993]

§ 216.56 Production Allocation Schedule Report.

(a) Any operator of an offshore Facility Measurement Point (FMP) handling production from a Federal lease or federally-approved agreement that is commingled (with approval) with production from any other source prior to measurement for royalty determination must file a Production Allocation Schedule Report (Form MMS–4058). This report is not required whenever all of the following conditions are met:

(1) All leases involved are Federal leases;

(2) All leases have the same fixed royalty rate;

(3) All leases are operated by the same operator;

(4) The facility measurement device is operated by the same person as the leases/agreements;

(5) Production has not been previously measured for royalty determination; and

(6) The production is not subsequently commingled and measured for royalty determination at an FMP for which Form MMS–4058 is required under this part.

(b) A completed Form MMS–4058 must be filed for each calendar month, beginning with the month in which handling of production covered by this section is initiated, and must be filed on or before the 15th day of the second month following the month being reported.

[58 FR 45255, Aug. 27, 1993. Redesignated at 58 FR 64903, Dec. 10, 1993]

§ 216.57 Stripper royalty rate reduction notification.

In accordance with its regulations at 43 CFR 3103.4–1, titled ''Waiver, suspension, or reduction of rental, royalty, or minimum royalty,'' the Bureau of Land Management (BLM) may grant reduced royalty rates to operators of low producing oil leases to encourage continued production. Operators who have been granted a reduced royalty rate(s) by BLM must submit a Stripper Royalty Rate Reduction Notification (Form MMS–4377) to MMS for each 12-month qualifying period that a reduced royalty rate(s) is granted.

[58 FR 64903, Dec. 10, 1993]

Subpart C—Oil and Gas, Onshore [Reserved]

Subpart D—Oil, Gas, and Sulfur, Offshore [Reserved]

Subpart E—Solid Minerals, General

§ 216.200 [Reserved]

§ 216.201 Mine Information Report.

The Mine Information Form (Form MMS–4050) must be filed for each mine that includes Federal or Indian leases

in its approved mining plan. The completed form must be filed by the operator of the mine/lease(s). Form MMS–4050 must be filed at the request of the MMS initially during the conversion of the mine/lease(s) to the PAAS.

§ 216.202 Facility and Measurement Information Form.

The Facility and Measurement Information Form (Form MMS–4051) must be filed for each facility or measurement device which handles solid mineral production from any Federal or Indian lease, or federally approved agreement, through the point of first sale or the point of royalty computation, whichever is applicable. The completed form must be filed by the operator of the facility or measurement device. Form MMS–4051 must be filed initially at the request of the MMS during the conversion of facility and measurement device operators to the PAAS. Subsequent to conversion, Form MMS–4051 must be filed with MMS/RMP no later than 30 days after establishment of a new facility or measurement device, or a change to any existing facility or measurement device that handles production attributable to any Federal or Indian lease, or federally approved agreement, through the point of first sale or royalty computation, whichever is applicable.

§ 216.203 Solid Minerals Operations Report.

The Solid Minerals Operation Report (Form MMS–4059) must be submitted by all Federal and Indian lease operators of producing mines that are part of an approved mine plan. Form MMS–4059 must be filed for the same period established for payment for royalties in the lease terms, unless a different reporting frequency is established by an MMS authorized official, and on or before the 15th day of the second month following the period being reported until all the leases within a mine are terminated or until omission of the report is authorized by the MMS.

§ 216.204 Solid Minerals Facility Report.

The Solid Minerals Facility Report (Form MMS–4060) must be filed by operators of secondary processing facilities that handle production attributable to Federal or Indian leases where royalty is determined after processing. The report period is monthly, unless a longer period is specified in the lease document, or otherwise approved by the MMS. The Form MMS–4060 must be filed on or before the 15th day of the second month following the period being reported.

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—Indian Land [Reserved]

PART 217—AUDITS AND INSPECTIONS

Subpart A—General Provisions [Reserved]

Subpart B—Oil and Gas, General

Sec.
217.50 Audits of records.
217.51 Lease account reconciliation.
217.52 Definitions.

Subpart C—Oil and Gas, Onshore [Reserved]

Subpart D—Oil, Gas and Sulfur, Offshore [Reserved]

Subpart E—Coal

217.200 Audits.

Subpart F—Other Solid Minerals

217.250 Audits.

Subpart G—Geothermal [Reserved]

Subpart H—Indian Lands [Reserved]

AUTHORITY: 35 Stat. 312; 35 Stat. 781, as amended; secs. 32, 6, 26, 41 Stat. 450, 753, 1248; secs. 1, 2, 3, 44 Stat. 301, as amended; secs. 6, 3, 44 Stat. 659, 710; secs. 1, 2, 3, 44 Stat. 1057; 47 Stat. 1487; 49 Stat. 1482, 1250, 1967, 2026; 52 Stat. 347; sec. 10, 53 Stat. 1196, as amended; 56 Stat. 273; sec. 10, 61 Stat. 915; sec. 3, 63 Stat. 683; 64 Stat. 311; 25 U.S.C. 396, 396a–f, 30 U.S.C. 189, 271, 281, 293, 359. Interpret or apply secs. 5, 5, 44 Stat. 302, 1058, as amended; 58 Stat. 483–485; 5 U.S.C. 301, 16 U.S.C. 508b, 30

U.S.C. 189, 192c, 271, 281, 293, 359, 43 U.S.C. 387, unless otherwise noted.

Subpart A—General Provisions [Reserved]

Subpart B—Oil and Gas, General

AUTHORITY: The Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 *et seq.).*

SOURCE: 49 FR 37345, Sept. 21, 1984, unless otherwise noted.

§ 217.50 Audits of records.

The Secretary, or his/her authorized representative, shall initiate and conduct audits relating to the scope, nature and extent of compliance by lessees, operators, revenue payors, and other persons with rental, royalty, net profit share and other payment requirements on a Federal or Indian oil and gas lease. Audits also will relate to compliance with applicable regulations and orders. All audits will be conducted in accordance with the notice and other requirements of 30 U.S.C. 1717.

§ 217.51 Lease account reconciliation.

Specific lease account reconciliations shall be performed with priority being given to reconciling those lease accounts specifically identified by a State or Indian tribe as having significant potential for underpayment.

§ 217.52 Definitions.

Terms used in this subpart shall have the same meaning as in 30 U.S.C. 1702.

Subpart C—Oil and Gas, Onshore [Reserved]

Subpart D—Oil, Gas and Sulfur, Offshore [Reserved]

Subpart E—Coal

§ 217.200 Audits.

An audit of the accounts and books of operators/lessees for the purpose of determining compliance with Federal lease terms relating to Federal royalties may be required annually or at other times as directed by the Associate Director for Royalty Management. The audit shall be performed by a qualified independent certified public accountant or by an independent public accountant licensed by a State, territory, or insular possession of the United States or the District of Columbia, and at the expense of the operator/lessee. The operator/lessee shall furnish, free of charge, duplicate copies of audit reports that express opinions on such compliance to the Associate Director for Royalty Management within 30 days after the completion of each audit. Where such audits are required, the Associate Director for Royalty Management will specify the purpose and scope of the audit and the information which is to be verified or obtained.

[47 FR 33195, July 30, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983]

Subpart F—Other Solid Minerals

§ 217.250 Audits.

An audit of the lessee's accounts and books may be made annually or at such other times as may be directed by the mining supervisor, by certified public accountants, and at the expense of the lessee. The lessee shall furnish free of cost duplicate copies of such annual or other audits to the mining supervisor, within 30 days after the completion of each auditing.

[37 FR 11041, June 1, 1972. Redesignated at 48 FR 35641, Aug. 5, 1983]

Subpart G—Geothermal [Reserved]

Subpart H—Indian Lands [Reserved]

PART 218—COLLECTION OF ROYALTIES, RENTALS, BONUSES AND OTHER MONIES DUE THE FEDERAL GOVERNMENT

Subpart A—General Provisions

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218.10 Information collection.
218.40 Assessments for incorrect or late reports and failure to report.
218.41 Assessments for failure to submit payment of same amount as Form MMS–2014 or bill document or to provide adequate information.

218.42 Cross-lease netting in calculation of late-payment interest.

Subpart B—Oil and Gas, General

218.50 Timing of payment.
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218.57 Providing information and claiming rewards.

Subpart C—Oil and Gas, Onshore

218.100 Royalty and rental payments.
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218.102 Late payment or underpayment charges.
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218.104 Exemption of States from certain interest and penalties.
218.105 Definitions.

Subpart D—Oil, Gas and Sulfur, Offshore

218.150 Royalties, net profit shares, and rental payments.
218.151 Rentals.
218.152 Fishermen's Contingency Fund.
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218.154 Effect of suspensions on royalty and rental.
218.155 Method of payment.
218.156 Definitions.

Subpart E—Solid Minerals—General

218.200 Payment of royalties, rentals, and deferred bonuses.
218.201 Method of payment.
218.202 Late payment or underpayment charges.
218.203 Recoupment of overpayments on Indian mineral leases.

Subpart F—Geothermal Resources

218.300 Payment of royalties, rentals, and deferred bonuses.
218.301 Method of payment.
218.302 Late payment or underpayment charges.

Subpart G—Indian Lands [Reserved]

Authority: 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.A. 3335; 43 U.S.C. 1301 *et seq.* 1331 *et seq.*, 1801 *et seq.*

Subpart A—General Provisions

§ 218.10 Information collection.

The information collection requirements contained in this part have been approved by OMB under 44 U.S.C. 3501 et seq. The forms, filing date, and approved OMB clearance numbers are identified in 30 CFR 210.10.

[57 FR 41867, Sept. 14, 1992]

§ 218.40 Assessments for incorrect or late reports and failure to report.

(a) An assessment of an amount not to exceed $10 per day may be charged for each report not received by MMS by the designated due date.

(b) An assessment of an amount not to exceed $10 may be charged for each incorrectly completed report.

(c) For purposes of reports required for the Auditing and Financial System (AFS), a report is defined as each line item on a Form MMS–2014. The line item consists of the various information, such as Product Code or Selling Arrangement Code, relating to each Accounting Identification Number (AID).

(d) An assessment under this section shall not be shared with a State, Indian tribe, or Indian allottee.

(e) The amount of the assessment to be imposed pursuant to paragraphs (a) and (b) of this section shall be established periodically by MMS. The assessment amount for each violation will be based on MMS's experience with costs and improper reporting. The MMS will publish a Notice of the assessment amount to be applied in the FEDERAL REGISTER.

[49 FR 37346, Sept. 21, 1984. Redesignated and amended at 51 FR 15767, Apr. 28, 1986; 52 FR 27546, July 22, 1987; 52 FR 37452, Oct. 7, 1987; 57 FR 52720, Nov. 5, 1992; 59 FR 38906, Aug. 1, 1994]

§ 218.41 Assessments for failure to submit payment of same amount as Form MMS–2014 or bill document or to provide adequate information.

(a) An assessment of an amount not to exceed $250 may be charged when the amount of a payment submitted by a payor is not equivalent in amount to the total of individual line items on the associated Form MMS 2014 or bill

document, unless the difference in amount has been authorized by MMS.

(b) An assessment of an amount not to exceed $250 may be charged for each payment submitted by a payor that cannot be automatically applied by AFS to the associated Form MMS–2014 or bill document because of inadequate or erroneous information submitted by the payor. For purposes of this section, inadequate or erroneous information is defined as:

(1) Absent or incorrect payor assigned document number, required to be identified by the payor in Block 3a on a Form MMS–2014, or the reuse of the same payor assigned document (''3a'') number in a subsequent reporting period.

(2) Absent or incorrect bill document invoice number (to include the four character alpha prefix and the eight digit number) or the payor-assigned 3a number required to be identified by the payor on the associated payment document, or the reuse of the same payor assigned 3a number in a subsequent reporting period.

(3) Absent or incorrect name of the administering Bureau of Indian Affairs Agency/Area office and the word ''allotted'' or the tribe name on payment documents remitted to MMS for an Indian tribe or allottee. If the payment is made by EFT, the payor must identify the tribe/allottee on the EFT message by a pre-established five digit code.

(4) Absent or incorrect MMS assigned payor code on a payment document.

(c) For purposes of this section, the term ''Form MMS–2014'' includes submission of reports of royalty information by magnetic media. Magnetic media submissions include submissions by magnetic tape, magnetic cartridge, or floppy diskette.

(d) For purposes of this section, a bill document is defined as any Bill of Collection (Form DI–1040b) that has been issued by MMS for assessments, late-payment interest charges, or other amounts owed.

(e) For purposes of this section, a payment document is defined as one of the payment methods identified in § 218.51(a)(3).

(f) The amount of the assessment to be imposed pursuant to paragraphs (a) and (b) of this section shall be established periodically by MMS. The assessment amount will be based on MMS' experience with costs and improper reporting and/or payment as specified in this section. The MMS will publish a Notice in the FEDERAL REGISTER of the assessment amount to be applied with the effective date.

[58 FR 45438, Aug. 30, 1993]

§ 218.42 Cross-lease netting in calculation of late-payment interest.

(a) Interest due from a payor on any underpayment for any Federal mineral lease or leases (onshore or offshore) and on any Indian tribal mineral lease or leases for any production month shall not be reduced by offsetting against that underpayment any overpayment made by the payor on any other lease or leases, except as provided in paragraph (b) of this section. Interest due from a payor or any underpayment on any Indian allotted lease shall not be reduced by offsetting against any overpayment on any other Indian allotted lease under any circumstances.

(b) Royalties attributed to production from a lease or leases which should have been attributed to production from a different lease or leases may be offset to determine whether and to what extent an underpayment exists on which interest is due if the following conditions are met:

(1) The error results from attributing and reporting an equal volume of production, produced from a lease or leases during a particular production month, to a different lease or leases from which it was not produced for the same or another production month;

(2) The payor is the same for the lease or leases to which production was attributed and the lease or leases to which it should have been attributed;

(3) The payor submits production reports, pipeline allocation reports, or other similar documentary evidence pertaining to the specific production involved which verifies the correct production information;

(4) The lessor is the same for the leases involved (in the case of Indian tribal leases, the same tribe is the lessor); and

(5) The ultimate recipients of any royalty or other lease revenues under

any applicable permanent indefinite appropriations are the same for, and receive the same percentage of revenue from, the leases.

(c) If MMS assesses late-payment interest and the payor asserts that some or all of the interest assessed is not owed pursuant to the exception set forth in paragraph (b) of this section, the burden is on the payor to demonstrate that the exception applies in the specific circumstances of the case.

(d) The exception set forth in paragraph (b) of this section shall not operate to relieve any payor of liability imposed by statute or regulation for erroneous reporting.

[57 FR 62206, Dec. 30, 1992]

Subpart B—Oil and Gas, General

SOURCE: 49 FR 37346, Sept. 21, 1984, unless otherwise noted.

§ 218.50 Timing of payment.

(a) Royalty payments are due at the end of the month following the month during which the oil and gas is produced and sold except when the last day of the month falls on a weekend or holiday. In such cases, payments are due on the first business day of the succeeding month. Rental payments are due as specified by the lease terms.

(b) Payments made on a Bill for Collection (Form DI–1040b) are due as specified by the Bill. Bills for Collection will be issued and payable as final collection actions.

(c) All payments to MMS are due as specified and are not deferred or suspended by reason of an appeal having been filed unless such deferral or suspension is approved in writing by an authorized MMS official.

§ 218.51 How to make payments.

(a) *Definitions.*

ACH—Automated Clearing House. A type of EFT using the ACH network.

Courtesy Notice—An MMS-issued notice of rental or bonus due.

Deferred Bonus Payment—Lease bonus paid in equal annual installments over a specified number of years.

EFT—Electronic Funds Transfer. Any paperless transfer of funds a bank initiates through an electronic terminal. For MMS purposes, EFT is limited to FEDWIRE and ACH transfers.

FEDWIRE—A type of EFT using the Federal Reserve Wire network.

Invoice Document Identification—The MMS-assigned invoice document identification (four alpha and eight numeric characters).

Payment—Any monies for royalty, bonus, rental, late payment charge, assessment, penalty, or other money sent to MMS.

Person—Any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity). The term does not include Federal agencies.

Report—Form MMS–2014, *Report of Sales and Royalty Remittance.*

RIK—Royalty in kind.

(b) *General Instructions.* You must make all payments to MMS electronically to the extent it is cost effective and practical. If you pay money to MMS or to an Indian tribe or allottee, you must follow these procedures:

(1) If MMS instructs you to use EFT, you must use EFT for all payments to MMS and/or a tribe.

(2) Contact MMS before using EFT. MMS will provide you with EFT payment instructions.

(3) Separate any payments on a Federal lease from any payments on an Indian lease.

(4) If you are not required to use EFT, use one of the following types of payment documents. MMS prefers that you use these payment documents in the order presented:

(i) Commercial check drawn on a solvent bank;

(ii) Certified check;

(iii) Cashier's check;

(iv) Money order;

(v) Bank draft drawn on a solvent bank; or

(vi) Federal Reserve check.

(5) You must include your payor code on all payments.

(6) You must pay in U.S. dollars.

(c) *How to complete a non-EFT payment.* (1) Make any payment on a Federal lease payable to: ''Department of the Interior-Minerals Management Service'' or ''DOI–MMS.''

(2) For an Indian allottee payment, send a separate payment for each Bureau of Indian Affairs (BIA) agency or

area office represented by the leases on your report or invoice document. You must include the name of the applicable BIA agency or area office on your payment. Make your payment document payable to: ''Department of the Interior-Minerals Management Service for BIA [Name] Agency (allotted)'' or ''DOI-MMS for BIA [Name] Agency (allotted).''

(3) For an Indian tribal payment other than a lockbox payment, send a separate payment for each tribe represented by the leases on your report or invoice document. You must include the name of the Indian tribe on your payment. Make it payable to: ''Department of the Interior-Minerals Management Service for BIA [Name of Tribe]'' or ''DOI-MMS for BIA [Name of Tribe].''

(4) For an Indian tribal lockbox payment, follow the instructions MMS provides you on how to report and make the lockbox payment. These instructions are specific to each tribe's lockbox written agreement with the bank authorized to receive payments on the tribe's mineral leases. You will receive these instructions from MMS when you are required to use a tribal lockbox for reports and payments.

(d) *Where to send a non-EFT payment when you use the U.S. Postal Service.* (1) For a payment to an Indian tribal lockbox, send your payment to the appropriate tribal lockbox address.

(2) For a Federal nonproducing lease rental or deferred bonus payment, send it to:

Minerals Management Service, Royalty Management Program, P.O. Box 5640, Denver, CO 80217–5640.

(3) For all other Federal and Indian lease payments other than those going to an Indian tribal lockbox, send them to:

Minerals Management Service, Royalty Management Program, P.O. Box 5810, Denver, CO 80217–5810.

(e) *Where to send a non-EFT payment when you use a courier or overnight delivery service.* You should send this type of payment to:

Minerals Management Service, Royalty Management Program, Building 85, Denver Federal Center, Room A–212, Denver, CO 80225–0165.

(f) *How to prepare and what to include on your payment document.* (1) For Form MMS–2014 payments, you must include both your payor code (block 2) and your payor-assigned document number (block 3a).

(2) For invoice payments, including RIK invoice payments, you must include both your payor code and invoice document identification (four-letter prefix and eight-digit number).

(3) For bonus payments:

(i) For one-fifth bonus payments for offshore oil, gas, and sulphur leases, follow the instructions in the Notice of Lease Offering.

(ii) For payment of the four-fifths bonus for an offshore lease, use EFT and follow the instructions in § 218.155(c).

(iii) For the successful bidder's bonus in the competitive sale of a coal, geothermal, or offshore mineral (other than oil, gas or sulfur) lease, follow the instructions and terms of the Notice of Competitive Lease Sale.

(iv) For installment payments of deferred bonuses, you must use EFT.

(4) If you are paying a lease rental you must:

(i) See 30 CFR 218.155(c) for instructions on how to pay first-year rentals of an offshore oil, gas, or sulfur lease;

(ii) See the Notice of Lease Offering for instructions on how to pay first-year rentals other than those covered in paragraph (f)(4)(i) of this section.

(iii) Include the MMS Courtesy Notice, when provided, or write your payor code and government-assigned lease number on the payment document when paying a rental that is not reported on Form MMS–2014 and not paid by EFT.

(g) *When is a payment to MMS due?* (1) All payments are due to MMS at the time law, regulation, or lease terms require unless MMS approves a change according to 30 CFR 243.2, ''Suspensions of orders or decisions pending appeal.'' If you file an appeal, and the requirement to submit payment is suspended, the original payment due date for purposes such as calculating late payment interest is not changed.

(2) If you use the U.S. Postal Service, courier, or overnight mail to send your

payment, it is due at the MMS addresses in paragraphs (d) and (e) of this section before 4 p.m. Mountain Time on the due date, regardless of when you sent it.

(3) If you use EFT to send your payment, it is due in the MMS account by the payment due date. You are responsible for your actions or your bank's actions that cause a late or incorrect payment. You will not be held responsible for mechanical or system failures of EFT payments.

(h) *What happens if payments are late or overdue?*

(1) If MMS receives your payment late, MMS will impose a late-payment interest charge under 30 CFR 218.54.

(2) If you do not pay an amount you owe, MMS may assess civil penalties under 30 CFR 241.20 and 241.51 or other applicable regulations.

[62 FR 19498, Apr. 22, 1997]

§ 218.52 Designated payor.

(a) When the lessee or revenue payor assigns any paying responsibility to any other entity, MMS must be notified within 30 days of the assignment.

(b) MMS may, by order, designate a lessee or revenue payor on a lease as the single payor for all revenues due and owing from that lease.

§ 218.53 Recoupment of overpayments on Indian mineral leases.

(a) Whenever an overpayment is made under an Indian oil and gas lease, a payor may recoup the overpayment through a recoupment on Form MMS–2014 against the current month's royalties or other revenues owed on the same lease. However, for any month a payor may not recoup more than 50 percent of the royalties or other revenues owed in that month under an individual allotted lease or more than 100 percent of the royalties or other revenues owed in that month under a tribal lease.

(b) With written permission authorized by tribal statute or resolution, a payor may recoup an overpayment against royalties or other revenues owed in that month under other leases for which that tribe is the lessor. A copy of the tribe's written permission must be furnished to MMS pursuant to instructions for reporting recoupments in the MMS ''Oil and Gas Payor Handbook.'' See 30 CFR 210.53. Recouping overpayments on one allotted lease from royalties paid to another allotted lease is specifically prohibited.

(c) Overpayments subject to recoupment under this section include all payments made in excess of the required payment for royalty, rental, bonus, or other amounts owed as specified by statute, regulation, order, or terms of an Indian mineral lease.

(d) The MMS Director or his/her designee may order any payor to not recoup any amount for such reasonable period of time as may be necessary for MMS to review the nature and amount of any claimed overpayment.

[60 FR 3087, Jan. 13, 1995]

§ 218.54 Late payments.

(a) An interest charge shall be assessed on unpaid and underpaid amounts from the date the amounts are due.

(b) The interest charge on late payments shall be at the underpayment rate established by the Internal Revenue Code, 26 U.S.C. 6621(a)(2) (Supp. 1987).

(c) Interest will be charged only on the amount of the payment not received. Interest will be charged only for the number of days the payment is late.

(d) A portion of the interest collected will be paid to a State where the State shares in mineral revenues from Federal leases.

(e) An overpayment on a lease or leases may be offset against an underpayment on a different lease or leases to determine a net underpayment on which interest is due pursuant to conditions specified in § 218.42.

[49 FR 37346, Sept. 21, 1984, as amended at 55 FR 37230, Sept. 10, 1990; 57 FR 62206, Dec. 30, 1992]

§ 218.55 Interest payments to Indians.

(a) All interest collected from unpaid or underpayments on Indian tribal or allotted leases will be paid to the tribe or allottee.

(b) Any disbursement of Indian mineral revenues not made by the due date as required in § 219.103 of this chapter shall accrue interest.

(c) Interest shall be computed at the underpayment rate established by the Internal Revenue Code, 26 U.S.C. 6621(a)(2) (Supp. 1987).

(d) The interest shall be payable only for the number of days the disbursement is late.

[49 FR 37346, Sept. 21, 1984, as amended at 55 FR 37230, Sept. 10, 1990]

§ 218.56 Definitions.

Terms used in this subpart shall have the same meaning as in 30 U.S.C. 1702.

[49 FR 37346, Sept. 21, 1984. Redesignated at 51 FR 15767, Apr. 28, 1986]

§ 218.57 Providing information and claiming rewards.

(a) *General.* (1) If a person has any information that could lead to the recovery of royalty or other payments owed to the United States with respect to any oil and gas lease on Federal lands or the Outer Continental Shelf, such information may be provided to the Minerals Management Service (MMS) in accordance with this paragraph. The MMS is authorized, under the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. 1723, to pay a reward for information with respect to Federal oil and gas leases. Funds must be appropriated before payment of any reward. Criteria and procedures covering claims for and payment of rewards are provided in paragraphs (b), (c), and (d) of this section.

(2) If a person has any information he or she believes would be valuable to MMS, that person (''informant'') should submit the information in writing, in the form of a letter, mailed or delivered in person to the Director, Minerals Management Service, Department of the Interior, 18th and C Street, NW., Washington, DC 20240, or to the Director's designated representative. Although written communications are preferred, oral information will be accepted.

(3) The informant should provide all data he or she has with respect to royalty or other payments owed. The information provided should include: identification of the alleged debtor; the source of the informant's knowledge of royalties or other payments owed; the date, if known, of the indebtedness; and any other information that could be used to establish indebtedness. All information received by MMS from persons providing information will be considered ''highly confidential'' and will not be disclosed to any individual except on a ''need to know'' basis in the performance of official duties.

(b) *Claim for reward.* (1) Any informant who provides information that could lead to the recovery of royalty or other payments may file a claim for reward unless the person is an officer or employee of the United States, an officer or employee of a State or Indian tribe acting pursuant to a cooperative agreement or delegation under the FOGRMA, or any person acting pursuant to a contract authorized by the FOGRMA.

(2) A claim for reward is not acceptable if filed on behalf of a claimant by his or her agent under power of attorney. However, an agent may provide MMS with information for an unidentified informant, to be evaluated and used by MMS as it deems appropriate. The informant's identity ultimately must be disclosed if the informant intends to file a claim for reward so that MMS can report the reward as taxable income to the Internal Revenue Service. An executor, administrator, or other legal representative of a deceased informant may file a claim on behalf of such deceased informant if, prior to his or her death, the informant was eligible to file a claim under this section. The representative must attach to the claim evidence of authority to file it.

(3) To file a claim for reward the informant must:

(i) Notify the Director, MMS, or the person to whom the information was reported, that he/she is claiming a reward.

(ii) Request an ''Application for Reward for Original Information'' (Form MMS–4280). This form provides for information to enable MMS to determine and pay rewards, to control reward applications, and to report a claimant's reward as taxable income to the Internal Revenue Service.

(iii) File a claim for reward by completing Form MMS–4280, sign it with his or her true name, and mail or deliver it in person to the Director or to

the Director's designated representative. If the informant provided the information in person, the claim should include the name and title of the person to whom the information was reported and the date that it was reported.

(4) If the informant used an identity other than his or true name when the information was originally reported, the person should attach proof to the claim that he or she is the person who gave the information. The MMS does not disclose the identity of its informants to unauthorized persons.

(c) *Basis for rejection of claims.* No reward will be paid to a claimant:

(1) Where the information originally furnished was deemed unworthy of initiating an investigation, but at some later date the records of the lessee are examined without reference to the information furnished. The claim will be rejected on the basis that the information did not cause the investigation nor did it, in itself, result in any recovery.

(2) For information that would have been discovered during the normal course of an audit or investigation.

(3) Unless the informant's true identity is disclosed.

(4) Until after all of the royalties, penalties, or other payments discovered to be owed as a result of information provided are collected and no longer subject to dispute.

(5) Unless funds are appropriated for the payment of rewards.

(d) *Basis for allowance of claims.* (1) The value of the information furnished in relation to the facts developed by the investigation will be taken into account in determining whether a reward shall be paid and, if so, the amount thereof. Information must be voluntarily given and upon the informant's own initiative to warrant the allowance of a reward. Information secured by representatives of MMS from witnesses and others in the course of their investigative activities does not constitute a basis for reward.

(2) In determining whether a reward will be allowed and, if so, the amount thereof, consideration will be given to any corresponding adjustment(s) which will result in potential savings to the lessee for other leases owned by the lessee or an affiliate of the lessee. An example of such an adjustment is a reduction in royalty payment on a different lease as the result of a revised allocation under a unitization or communitization agreement or from an offshore pipeline system. Rewards otherwise allowable will be reduced or rejected by reason of such offsetting adjustments.

(3) If several claims filed by one informant are considered in one recommendation, the reward, if any, may be allowed on one claim and the others may be closed by reference.

(4) Where an informant has provided information and filed a claim for reward with respect to royalty reports of one lessee for several leases, no reward will be granted with respect to an individual lease which has been examined until examination of all leases involved has been completed. Because the possibility exists that adjustments made to the reports for the open leases may result in offsetting adjustments, no reward will be allowed until the overall results of the information are evaluated.

(e) *Amount and payment of reward.* (1) The Director, MMS will determine whether a reward will be paid and, if so, the amount thereof. In making this decision, the information provided will be evaluated in relation to the facts developed by the resulting investigation. Claims for reward will be paid in proportion to the value of information furnished voluntarily and on the informant's own initiative with respect to recovered royalties or other payments. The amount of reward will be determined as follows:

(i) For specific and responsible information that caused the investigation and resulted in recovery, the reward will be 10 percent of the first $75,000 recovered, 5 percent of the next $25,000, and 1 percent of any additional recovery. The total reward cannot exceed $100,000.

(ii) For information that caused the examination and was of value in determining royalty or other payments due, although not specific, and for information that was a direct factor in recovering royalty or other payments, the reward will be 5 percent of the first $75,000 recovered, 2½ percent of the

next $25,000, and ½ percent of any additional recovery. The total reward cannot exceed $100,000.

(iii) For information that caused the investigation but was of no value in determining royalty or other payments due, the reward will be 1 percent of the first $75,000 recovered and ½ percent of any additional recovery. The total reward cannot exceed $100,000.

(2) Rewards will be paid only if moneys are appropriated for that purpose. Subject to appropriations, payments will be made as soon as possible after collection of the amounts owed by the lessee, and after those amounts no longer are subject to dispute by the payor. The reward payment to an informant will be net of Federal and State income tax in accordance with withholding guidelines of the Internal Revenue Service and the applicable State(s).

(3) A decision by the Director, MMS, either denying a reward or establishing the amount of any reward is a final departmental action and may not be appealed to the Interior Board of Land Appeals in accordance with the provisions of 30 CFR part 290.

(Approved by the Office of Management and Budget under control number 1010–0076)

[52 FR 24451, July 1, 1987]

Subpart C—Oil and Gas, Onshore

§ 218.100 Royalty and rental payments.

(a) *Payment of royalties and rentals.* As specified under the provisions of the lease, the lessee shall submit all rental payments when due and shall pay in value or deliver in production all royalties in the amounts of value or production determined by MMS to be due.

(b) If the lessor elects to take royalty in oil or gas, unless otherwise agreed upon, such royalty shall be delivered on the leasehold, by the lessee to the order of and without cost to the lessor, as instructed by the Associate Director.

(c) *Method of payment.* The payor shall tender all payments in accordance with 30 CFR 218.51.

[47 FR 47773, Oct. 27, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, and amended at 52 FR 23815, June 25, 1987]

§ 218.101 Royalty and rental remittance (naval petroleum reserves).

Remittance covering payments of royalty or rental on naval petroleum reserves must be accomplished by necessary identification information and sent direct to the Director, Naval Petroleum Reserves in California.

[47 FR 47773, Oct. 27, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983]

§ 218.102 Late payment or underpayment charges.

(a) The failure to make timely or proper payments of any monies due pursuant to leases, permits, and contracts subject to these regulations will result in the collection by the MMS of the full amount past due plus a late payment charge. Exceptions to this late payment charge may be granted when estimated payments on minerals production have already been made timely and otherwise in accordance with instructions provided by MMS to the payor. However, late payment charges assessed with respect to any Indian lease, permit, or contract shall be collected and paid to the Indian or tribe to which the amount overdue is owed.

(b) Late payment charges will be assessed on any late payment or underpayment from the date that the payment was due until the date that the payment was received at the MMS addresses specified in § 218.51(f)(1) and (f)(2). Payments received at the specified MMS addresses after 4 p.m. mountain time are considered received the following business day.

(c) Late payment charges apply to all underpayments and payments received after the date due. The charges include production and minimum royalties; assessments for liquidated damages; administrative fees and payments by purchasers of royalty taken-in-kind; or any other payments, fees, or assessments that a lessee/operator/permittee/payor/royalty taken-in-kind purchaser is required to pay by a specified date. The failure to pay past due amounts, including late-payment charges, will result in the initiation of other enforcement proceedings.

(d) An overpayment on a lease or leases may be offset against an underpayment on a different lease or leases

to determine a net underpayment on which interest is due pursuant to conditions specified in § 218.42.

[47 FR 47773, Oct. 27, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, and amended at 49 FR 37347, Sept. 21, 1984; 57 FR 41868, Sept. 14, 1992; 57 FR 62206, Dec. 30, 1992]

§ 218.103 Payments to States.

(a) Any amount that is payable by MMS to a State but is not paid on the due date, as specified in § 219.100 of this chapter, or that is held in a suspense account pending resolution of a dispute as specified in § 219.101 of this chapter, shall accrue interest payable to the State.

(b) Interest shall be computed at the underpayment rate established by the Internal Revenue Code, 26 U.S.C. 6621(a)(2) (Supp. 1987).

(c) Interest shall be computed only for the number of days the disbursement is late. In the case of suspended amounts subject to interest, it shall be computed beginning with the calendar day following the day that the monies normally would have been paid to the State had they not been in suspense.

[49 FR 37347, Sept. 21, 1984, as amended at 55 FR 37230, Sept. 10, 1990]

§ 218.104 Exemption of States from certain interest and penalties.

(a) States are exempt from being assessed for any interest or penalties found to be due against the Department of the Interior for failure to comply with the Emergency Petroleum Allocation Act of 1973, as amended, or any regulation issued by the Secretary of Energy thereunder concerning the certification or processing of crude oil taken in-kind as royalty by the Secretary.

(b) Any State shall be assessed for its share of any overcharge resulting from a determination that DOI failed to comply with the Emergency Petroleum Allocation Act of 1973, as amended. Each State's share shall be assessed against monies owed to the State. Such assessment shall be first against monies owed to such State as a result of royalty audits prior to January 12, 1983, the enactment date of the Federal Oil and Gas Royalty Management Act of 1982, then against other monies owed. The State shall be liable for any balance.

(c) A State's liability for repayment of an overcharge under this section shall exist for any amounts resulting from a judgment in a civil suit or as the result of settlement of a claim through a negotiated agreement. State liability would be offset against future mineral revenue distributions to the State.

[49 FR 37347, Sept. 21, 1984]

§ 218.105 Definitions.

Terms used in this subpart have the same meaning as in 30 U.S.C. 1702.

[49 FR 37347, Sept. 21, 1984]

Subpart D—Oil, Gas and Sulfur, Offshore

§ 218.150 Royalties, net profit shares, and rental payments.

(a) As specified under the provisions of the lease, the lessee shall submit all rental payments when due and shall pay in value or deliver in production all royalties and net profit shares in the amounts of value or production determined by MMS to be due.

(b) The failure to make timely or proper payments of any monies due pursuant to leases, permits, and contracts subject to these regulations will result in the collection of the amount past due plus a late payment charge. Exceptions to this late payment charge may be granted when estimated payments on minerals production have already been made timely and otherwise in accordance with instructions provided by MMS to the payor.

(c) Late payment charges will be assessed on any late payment or underpayment from the date that the payment was due until the date that the payment was received at the MMS addresses specified in § 218.51(f)(1) and (f)(2). Payments received at the specified MMS addresses after 4 p.m. mountain time are considered received the following business day.

(d) Late payment charges apply to all underpayments and payments received after the date due. These charges include production and minimum royalties; assessments for liquidated damages; administrative fees and payments

by purchasers of royalty taken-in-kind; or any other payments, fees, or assessments that a lessee/operator/payor/permittee/royalty taken-in-kind purchaser is required to pay by a specified date. The failure to pay past due amounts, including late payment charges, will result in the initiation of other enforcement proceedings.

(e) An overpayment on a lease or leases, excluding rental payments, may be offset against an underpayment on a different lease or leases to determine a net underpayment on which interest is due pursuant to conditions specified in § 218.42.

[47 FR 22528, May 25, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, and amended at 49 FR 37347, Sept. 21, 1984; 52 FR 23815, June 25, 1987; 57 FR 41868, Sept. 14, 1992; 57 FR 62206, Dec. 30, 1992]

§ 218.151 Rentals.

(a) Except for leases issued subject to net profit sharing provisions, an annual rental shall be due and payable in advance, at the rate specified in the oil and gas leases, on the first day of each lease year prior to discovery of oil or gas on the lease.

(b) The owner of any lease created by the segregation of a portion of a producing lease which is not subject to net profit sharing provisions and on which segregated portion there is no production, actual or allocated, shall pay an annual rental for such segregated portion at the rate per acre or hectare specified in the lease. This rental shall be payable each lease year following the year in which the segregation became effective and prior to a discovery on such segregated portion.

(c) Annual rental paid in any year shall be in addition to, and shall not be credited against, any royalties due from production.

(d) An annual rental on a lease for a mineral other than oil or gas, shall be due and payable, in advance, on the first day of each lease year prior to discovery in paying quantities, at a rate specified in the lease form.

(e) For leases issued subject to the net profit sharing provisions, annual rental payments shall be due and payable in advance, on the first day of each lease year which commences prior to the date the first profit share payment becomes due. The owner of any lease created by the segreation of a portion of a lease subject to net profit sharing provisions, shall pay an annual rental for such segregated portion at the rate per acre or hectare specified in the lease. This rental shall be payable each year following the year in which the segregation becomes effective and shall continue to be due and payable, in advance, on the first day of each year which commences prior to the date the first profit share payment becomes due.

[44 FR 38276, June 29, 1979, as amended at 45 FR 69175, Oct. 17, 1980; 47 FR 25972, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982, and at 48 FR 35641, Aug. 5, 1983]

§ 218.152 Fishermen's Contingency Fund.

Upon the establishment of the Fishermen's Contingency Fund, any holder of a lease issued or maintained under the Outer Continental Shelf Lands Act and any holder of an exploration permit or of an easement or right-of-way for the construction of a pipeline, shall pay an amount specified by the Director, MMS, who shall assess and collect the specified amount from each holder and deposit it into the Fund. With respect to prelease exploratory drilling permits, the amount will be collected at the time of issuance of the permit.

[52 FR 5458, Feb. 23, 1987]

§ 218.153 [Reserved]

§ 218.154 Effect of suspensions on royalty and rental.

(a) If under the provisions of 30 CFR 250.10 (b)(2) through (b)(4), the Regional Supervisor, with respect to any lease, directs the suspension of both operations and production, or, with respect to a lease on which there is no producible well, directs the suspension of operations, no payment of rental or minimum royalty shall be required for or during the period of suspension.

(b) The lessee shall not be relieved of the obligation to pay rental, minimum royalty or royalty for or during the period of suspension if the Regional Supervisor:

(1) Under the provisions of 30 CFR 250.10(a) approves, at the request of a

lessee, the suspension of operations or production, or both, or

(2) Under the provisions of 30 CFR 250.10(b)(1), (b)(5) through (b)(7), or (c) suspends any operation, including production.

(c) If the lease anniversary date falls within a period of suspension for which no rental or minimum royalty payments are required under paragraph (a) of this section, the prorated rentals or minimum royalties are due and payable as of the date the suspension period terminates. These amounts shall be computed and notice thereof given the lessee. The lessee shall pay the amount due within 30 days after receipt of such notice. The anniversary date of a lease shall not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979. Redesignated and amended at 47 FR 47006, 47007, Oct. 22, 1982. Further redesignated at 48 FR 35641, Aug. 5, 1983 and amended at 51 FR 19063, May 27, 1986; 54 FR 50616, Dec. 8, 1989]

§ 218.155 Method of payment.

(a) *Payment of royalties and rentals.* With the exception of first-year rental, the payor shall tender all payments in accordance with § 218.51 of this part. First-year rental shall be paid in accordance with paragraph (c) of this section.

(b) *Payment of the one-fifth bonus bid amount.* (1) Each lease bid must include a payment for the one-fifth bonus bid deposit amount unless the bidder is otherwise directed by the Secretary. Further instructions on how to make payment with the bid will be included in the notice of each lease offering. EFT may be used as a method of payment for the one-fifth bonus bid amount.

(2) Beginning with lease offerings held after February 1, 1984, the one-fifth bonus amount received from a high bidder shall be deposited into an escrow account created pursuant to an agreement between the Departments of the Interior and Treasury, pending acceptance or rejection of the bid. The one-fifth bonus funds will be invested in public debt securities. Investment of this amount by the U.S. Government does not indicate acceptance of the bid. The one-fifth bonus checks submitted with bids other than the highest valid bid shall be returned to respective bidders after bids are opened, recorded, and ranked. Return of such checks will not affect the status, validity, or ranking of bids. The one-fifth bonus bid amount received from any high bidder and held by the Government pending acceptance or rejection, will be returned with actual interest earned, if the bid is subsequently rejected. The interest accrued during the period held in the account pending acceptance or rejection of the bid will accrue to the Government when the bid is accepted.

(c) *Payment of the four-fifths bonus bid amount and the first year's rental.* Payment shall be made to MMS by EFT unless otherwise directed by the Secretary. The payment by EFT via the FRCS must be received by the Federal Reserve Bank of New York no later than noon, eastern standard time, on the 11th business day after receipt of the lease forms by the successful bidder. A ''business day'' is considered to be a day on which the OCS regional office issuing the lease is open for business. The lease will not be executed by the appropriate MMS official until payment is received. Failure to remit by EFT or as directed by the Secretary within the time specified above will result in forfeiture of the one-fifth bonus bid amount and the lease will not be executed by the appropriate MMS official. Payors will not be held responsible for late payment due to actions beyond their control, such as mechanical or systems failure of FRCS or FDS. Payors will be held responsible for incorrect actions of their bank which result in late payments. A 2-day grace period will be allowed to make up a deficient payment, but a late payment charge will be assessed for this late payment and a penalty will also be assessed if appropriate. Late payment charges will be assessed in accordance with Subpart B of this part.

(d) *General.* (1) Payors using the appropriate means of payment (EFT, check, etc.) may pay for multiple lease obligations with a single remittance but must ensure that the payment complies with subpart B of this part and the remittance advice adequately

identifies the single payment. The format to be used for such identification will be provided by the MMS Accounting Center.

(2) Where to pay.

(3) The MMS mailing addresses for payments to MMS are specified in § 218.51 (f)(1) and (f)(2).

(4) Payments received at the MMS addresses after 4 p.m. mountain time are considered received the following business day.

(e) *Miscellaneous payments.* Payments shall be made to the manager of the appropriate Outer Continental Shelf field office by cash, check or bank draft payable to ''Department of the Interior—MMS'' for miscellaneous payments such as:

(1) Pipeline rights-of-way application filing fees and rentals, pipeline accessory site rentals and application fees, and other related costs.

(2) Filing and approval fees for transfers of interest in leases.

[49 FR 8605, Mar. 8, 1984, as amended at 52 FR 23815, June 25, 1987; 53 FR 43201, Oct. 26, 1988; 57 FR 41868, Sept. 14, 1992; 62 FR 19499, Apr. 22, 1997]

§ 218.156 Definitions.

Terms used in this subpart have the same meaning as in 30 U.S.C. 1702.

[52 FR 23815, June 25, 1987]

Subpart E—Solid Minerals—General

§ 218.200 Payment of royalties, rentals, and deferred bonuses.

As specified under the provisions of the lease, the lessee shall submit all rental and deferred bonus payments when due and shall pay in value all royalties in the amount determined by MMS to be due.

[52 FR 23815, June 25, 1987]

§ 218.201 Method of payment.

The payor shall tender all payments in accordance with 30 CFR 218.51.

[52 FR 23815, June 25, 1987]

§ 218.202 Late payment or underpayment charges.

(a) The failure to make timely or proper payment of any monies due pursuant to leases and contracts subject to these rules will result in the collection by MMS of the full amount past due plus a late payment charge. Exceptions to this late payment charge may be granted when estimated payments on minerals production have already been made timely and otherwise in accordance with instructions provided by MMS to the operator/lessee. However, late payment charges assessed with respect to any Indian lease, permit, or contract shall be collected and paid to the Indian or tribe to which the amount overdue is owed.

(b) Late payment charges will be assessed on any late payment or underpayment from the date that the payment was due until the date that the payment was received at the MMS addresses specified in 218.51(f)(1) and (f)(2). Payments received at the specified MMS addresses after 4 p.m. mountain time are considered received the following business day.

(c) The interest charge on late payments shall be at the underpayment rate established by section 6621(a)(2) of the Internal Revenue Code, 26 U.S.C. 6621(a)(2).

(d) Interest will be charged only on the amount of the payment not received by the designated due date. Interest will be charged only for the number of days the payment is late.

(e) Late payment charges apply to all underpayments and payments received after the date due. These charges include production, minimum, or advance royalties; assessments for liquidated damages; or any other payments, fees, or assessments that an operator/lessee is required to pay by a specified date. The failure to pay past due payments, including late payment charges, will result in the initiation of other enforcement proceedings.

(f) An overpayment on a lease or leases may be offset against an underpayment on a different lease or leases to determine a net underpayment on which interest is due pursuant to conditions specified in § 218.42.

[47 FR 33195, July 30, 1982; 47 FR 53366, Nov. 26, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, and further redesignated at 52 FR 23815, June 25, 1987; 57 FR 41868, Sept. 14, 1992; 57 FR 62207, Dec. 30, 1992; 59 FR 14559, Mar. 29, 1994]

§ 218.203 Recoupment of overpayments on Indian mineral leases.

(a) Whenever an overpayment is made under an Indian solid mineral lease, a payor may recoup the overpayment through a recoupment on Form MMS–2014 against the current month's royalties or other revenues owed on the same lease. However, for any month a payor may not recoup more than 50 percent of the royalties or other revenues owed in that month under an individual allotted lease or more than 100 percent of the royalties or other revenues owed in that month under a tribal lease.

(b) With written permission authorized by tribal statute or resolution, a payor may recoup an overpayment against royalties or other revenues owed in that month under other leases for which that tribe is the lessor. A copy of the tribe's written permission must be furnished to MMS pursuant to instructions for reporting recoupments in the ''AFS Payor Handbook—Solid Minerals.'' See 30 CFR 210.204. Recouping overpayments on one allotted lease from royalties paid to another allotted lease is specifically prohibited.

(c) Overpayments subject to recoupment under this section include all payments made in excess of the required payment for royalty, rental, bonus, or other amounts owed as specified by statute, regulation, order, or terms of an Indian mineral lease.

(d) The MMS Director or his/her designee may order any payor to not recoup any amount for such reasonable period of time as may be necessary for MMS to review the nature and amount of any claimed overpayment.

[60 FR 3087, Jan. 13, 1995]

Subpart F—Geothermal Resources

§ 218.300 Payment of royalties, rentals, and deferred bonuses.

As specified under the provisions of the lease, the lessee shall submit all rental and deferred bonus payments when due and shall pay in value all royalties in the amount determined by MMS to be due.

[52 FR 23815, June 25, 1987]

§ 218.301 Method of payment.

The payor shall tender all payments in accordance with 30 CFR 218.51.

[52 FR 23815, June 25, 1987]

§ 218.302 Late payment or underpayment charges.

(a) The failure to make timely or proper payment of any monies due pursuant to leases and contracts subject to these regulations will result in the collection by the Minerals Management Service (MMS) of the full amount past due plus a late payment charge. Exceptions to this late payment charge may be granted when estimated payments on minerals production have already been made timely and otherwise in accordance with the instructions provided by the MMS to the payor.

(b) Late payment charges will be assessed on any late payment or underpayment from the date that the payment was due until the date that the payment was received at the MMS addresses specified in § 218.51 (f)(1) and (f)(2). Payments received at the specified MMS addresses after 4 p.m. Mountain Time are considered received the following business day.

(c) The interest charge on late payments shall be at the underpayment rate established by section 6621(a)(2) of the Internal Revenue Code, 26 U.S.C. 6621(a)(2).

(d) Interest will be charged only on the amount of the payment not received by the designated due date. Interest will be charged only for the number of days the payment is late.

(e) Late payment charges apply to all underpayments and payments received after the date due. These charges include production, minimum, and compensatory royalties; assessments for liquidated damages; administrative fees and payments by purchasers of royalty taken-in-kind; or any other payments, fees, or assessments that a lessee/operator/payor/royalty taken-in-kind purchaser is required to pay by a specified date. The failure to pay past due payments, including late payment charges, will result in the initiation of other enforcement proceedings.

(f) An overpayment on a lease or leases may be offset against an underpayment on a different lease or leases

to determine a net underpayment on which interest is due pursuant to conditions specified in § 218.42.

[47 FR 22528, May 25, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, and further redesignated at 51 FR 15767, Apr. 28, 1986 and 52 FR 23815, June 25, 1987; 57 FR 41868, Sept. 14, 1992; 57 FR 62207, Dec. 30, 1992; 59 FR 14559, Mar. 29, 1994]

Subpart G—Indian Lands [Reserved]

PART 219—DISTRIBUTION AND DISBURSEMENT OF ROYALTIES, RENTALS, AND BONUSES

Subpart A—General Provision [Reserved]

Subpart B—Oil and Gas, General [Reserved]

Subpart C—Oil and Gas, Onshore

Sec.

219.100 Timing of payment to States.
219.101 Receipts subject to an interest charge.
219.102 Method of payment.
219.103 Payments to Indian accounts.
219.104 Explanation of payments to States and Indian tribes.
219.105 Definitions.

AUTHORITY: Section 104, Pub. L. 97–451, 96 Stat. 2451 (30 U.S.C. 1714).

SOURCE: 49 FR 37347, Sept. 21, 1984, unless otherwise noted.

Subpart A—General Provisions [Reserved]

Subpart B—Oil and Gas, General [Reserved]

Subpart C—Oil and Gas, Onshore

§ 219.100 Timing of payment to States.

A State's share of mineral leasing revenues shall be paid to the State not later than the last business day of the month in which the U.S. Treasury issues a warrant authorizing the disbursement, except for any portion of such revenues which is under challenge and placed in a suspense account pending resolution of a dispute.

§ 219.101 Receipts subject to an interest charge.

(a) Subject to the availability of appropriations, the Minerals Management Service (MMS) shall pay the State its proportionate share of any interest charge for royalty and related monies that are placed in a suspense account pending resolution of matters which will allow distribution and disbursement. Such monies not disbursed by the last business day of the month following receipt by MMS shall accrue interest until paid.

(b) Upon resolution, the suspended monies found due in paragraph (a) of this section, plus interest, shall be disbursed to the State under the provisions of § 219.100.

(c) Paragraph (a) of this section shall apply to revenues which cannot be disbursed to the State because the payor/lessee provided incorrect, inadequate, or incomplete information to MMS which prevented MMS from properly identifying the payment to the proper recipient.

§ 219.102 Method of payment.

The MMS shall disburse monies to a State either by Treasury check or by Electronic Funds Transfer (EFT). Should a State prefer to receive its payment by EFT, it should request this payment method in writing to the Minerals Management Service, Royalty Management Program, P.O. Box 5760, Denver, Colorado 80217–5760.

[57 FR 41868, Sept. 14, 1992, as amended at 58 FR 64903, Dec. 10, 1993]

§ 219.103 Payments to Indian accounts.

Mineral revenues received from Indian leases shall be transferred to the appropriate Indian accounts managed by the Bureau of Indian Affairs (BIA) for allotted and tribal revenues. These accounts are specifically designated Treasury accounts. Revenues shall be transferred to the Indian accounts at the earliest practicable date after such funds are received, but in no case later than the last business day of the month in which revenues are received by the MMS.

§ 219.104 Explanation of payments to States and Indian tribes.

(a) Payments to States and BIA on behalf of Indian tribes or Indian allottees discussed in this part shall be described in *Explanation of Payment* reports prepared by the MMS. These reports will be at the lease level and shall include a description of the type of payment being made, the period covered by the payment, the source of the payment, sales amounts upon which the payment is based, the royalty rate, and the unit value. Should any State or Indian tribe desire additional information pertaining to mineral revenue payments, the State or tribe may request this information from the MMS.

(b) The report shall be provided to: (1) States not later than the 10th day of the month following the month in which MMS disburses the State's share of royalties and related monies; (2) the BIA on behalf of tribes and Indian allottees not later than the 10th day of the month following the month the funds are disbursed by MMS.

(c) Revenues that cannot be distributed to States, tribes, or Indian allottees because the payor/lessee provided incorrect, inadequate, or incomplete information, preventing MMS from properly identifying the payment to the proper recipient, shall not be included in the reports until the problem is resolved.

§ 219.105 Definitions.

Terms used in this subpart shall have the same meaning as in 30 U.S.C. 1702.

PART 220—ACCOUNTING PROCEDURES FOR DETERMINING NET PROFIT SHARE PAYMENT FOR OUTER CONTINENTAL SHELF OIL AND GAS LEASES

Sec.

220.001 Purpose and scope.
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220.012 Overhead allowance.
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220.020 Calculation of the allowance for capital recovery.
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AUTHORITY: Sec. 205, Pub. L. 95–372, 92 Stat. 643 (43 U.S.C. 1337).

SOURCE: 45 FR 36800, May 30, 1980, unless otherwise noted. Redesignated at 48 FR 1182, Jan. 11, 1983, and at 48 FR 35642, Aug. 5, 1983.

§ 220.001 Purpose and scope.

(a) This part 220 establishes accounting procedures for determining the net profit share base and calculating net profit share payments due the United States for the production of oil and gas from OCS leases.

(b) The procedures established by this part 220 apply to any OCS lease issued by the Department of the Interior under any bidding system established by § 260.110(a) of this chapter which has a net profit share component.

[45 FR 36800, May 30, 1980, as amended at 46 FR 29689, June 2, 1981. Redesignated at 48 FR 1182, Jan. 11, 1983, and at 48 FR 35642, Aug. 5, 1983]

§ 220.002 Definitions.

For purposes of this part 220:

Allowance for capital recovery means the amount calculated according to procedures specified in § 220.020. This amount allows a premium for risk initially undertaken by the lessee and a return on investment made during the capital recovery period. It is provided in lieu of interest on equipment and materiel charged to the NPSL capital account.

Capital recovery period means the period of time that begins on the date of issuance of the NPSL and ends on the last day of the month during which the sooner of the following occurs:

(1) The lessee completes the last well on the first platform specified in the development and production plan originally approved by the MMS, with any approved amendments thereto, and installation of wellhead equipment. In the event the last well is dry, then the

capital recovery period shall be deemed to have ended with the determination that the last well is non-productive;

(2) The balance in the NPSL capital account changes from a debit balance to a credit balance; or

(3) The lessee, at his election, chooses to terminate the capital recovery period. A decision to terminate the capital recovery period prior to the events specified in paragraphs (a) (1) and (2) of this definition shall be communicated in writing to the Director and shall be irrevocable.

Controllable materiel means materiel which at the time is so classified in the Materiel Classification Manual as most recently recommended by the Council of Petroleum Accountants Societies of North America.

Cost means an expenditure or an accrual incurred by a lessee in conducting NPSL operations.

Cost pool means a grouping of costs identified with more than one OCS lease, whether the leases are NPSLs or other types of leases.

Credit means a payment, rebate, reimbursement to a lessee, or other reduction in cost or increase in revenue attributable to NPSL operations.

Direct cost means any cost listed in § 220.011 that benefits only NPSL operations.

Director means the Director of MMS, Washington, D.C., or his delegate.

Field employee means an employee below a first level supervisor who is directly employed in the NPSL project area.

First level supervisor means an employee whose primary function in NPSL operations is the direct supervision of other employees and/or contract labor directly employed on the NPSL project area in a field operating capacity.

G & G means geological, geophysical, geochemical and other similar investigations carried out on the NPSL tract.

Joint cost means any cost listed in § 220.011 that benefits NPSL operations and one or more other operations of the lessee or an outside party.

Lessee means a person authorized by an OCS lease, or an approved assignment thereof, to develop and produce oil and gas, including all parties holding such authority by or through the lessee, and the person designated to conduct NPSL operations.

Lessee's cost of allowed employee absence means the lessee's cost of holiday, vacation, sickness, disability benefits, jury duty and other customary excused allowances.

Materiel means equipment, apparatus, and supplies.

Net profit share base means the end of the month credit balance in the NPSL capital account determined pursuant to § 220.021. The net profit share base is the production revenue remaining after subtracting all allowable costs and adding all allowable credits (including production revenue) in accordance with the procedures established by this part 220.

Net profit share payment means the portion of the net profit share base payable to the United States.

Net profit share rate means the percentage share of the net profit share base payable to the United States. The percentage share may be fixed in the notice of OCS lease sale or be the bid variable, depending upon the bidding system used, as established by § 260.110(a) of this chapter.

NPSL means a net profit share lease, which is an OCS lease that provides for payment to the United States of a percentage share of the net profits for production of oil and gas from the tract. This percentage share may be fixed in the notice of OCS lease sale or be the bid variable, depending on the bidding system used, as established by § 260.110(a) of this chapter.

NPSL operations means all activities subsequent to issuance of the NPSL necessary and proper for the exploration, development, operation, maintenance, and final abandonment of the NPSL property.

NPSL project area means the NPSL tract, offshore facilities, and shore base facilities.

NPSL property means the NPSL tract, and materiel and offshore facilities acquired for use in NPSL operations and that are installed and/or used on the NPSL tract.

NPSL tract means a tract subject to an NPSL.

OCS lease means a Federal lease for oil and gas issued under the OCSLA.

OCS lease sale means the DOI proceeding by which leases for certain OCS tracts are offered for sale by competitive bidding and during which bids are received, announced, and recorded.

Offshore facilities means platform and support systems located offshore that are necessary to conduct NPSL operations, *e.g.*, oil and gas handling facilities, living quarters, offices, shops, cranes, electrical supply equipment and systems, fuel and water storage and piping, heliport, marine docking installations, communication facilities, and navigation aids.

Outside party means any person who is not a lessee.

Person means person as defined in part 260 of this chapter.

Personal expenses means travel and other reasonable reimbursable expenses of lessee's employees.

Production means all oil, gas, or other hydrocarbon products produced, removed, saved, or sold from the NPSL property. Gas and liquids of all kinds are included in production. Production includes the allocated share of production from a unit of which the NPSL is a part.

Production revenue means the value of all production attributable to an NPSL property, which value is determined in accordance with §260.110(b) of this chapter.

Railway receiving point or *recognized barge terminal* means the location that a vendor would use in determining the sale price to the lessee of new materiel to be delivered to the NPSL project area.

Reliable supply store means a recognized source or common stock point for the particular materiel involved.

Shore base facilities means onshore facilities necessary for NPSL operations, including:

(1) Shore base support facilities, *e.g.*, a receiving and trans-shipment point for materiel, staging area for shuttling personnel to and from the NPSL tract, a communication, scheduling, and dispatching center; and

(2) Shore base production facilities, e.g., pumps, separating facilities, gas plants, and tankage for production from the NPSL tract.

Technical employees means those employees having special and specific engineering, geological or other professional skills, and whose primary function in NPSL operations is the handling and resolution of specific operating conditions and problems for the benefit of NPSL operations.

Tract means land located on the OCS that is offered for lease through an OCS lease sale and that is identified by a leasing map or an official protraction diagram prepared by DOI.

[45 FR 36800, May 30, 1980, as amended at 46 FR 29689, June 2, 1981. Redesignated and amended at 48 FR 1182, Jan. 11, 1983. Redesignated at 48 FR 35642, Aug. 5, 1983]

§ 220.003 Information collection.

(a) The information collection requirements of this part have been approved by OMB under 44 U.S.C. 3501 et seq. and assigned OMB Clearance Number 1010–0073. The information will be used to determine all allowable direct and allocable joint costs incurred during the term of the lease, appropriate overhead allowances permitted on these costs pursuant to §220.012, and allowances for capital recovery calculated pursuant to §220.020. The information collection is mandatory in accordance with the Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. 1701 et seq.

(b) Public reporting burden is estimated to average 16 hours for each annual and monthly lease report, including time spent reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing burden, to the Information Collection Clearance Officer, Minerals Management Service, 281 Elden Street, Herndon, Virginia 22070; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project 1010–0073, Washington, DC 20503.

[57 FR 41868, Sept. 14, 1992, as amended at 58 FR 64903, Dec. 10, 1993]

§ 220.010 NPSL capital account.

(a) For each NPSL tract, an NPSL capital account shall be established and maintained by the lessee for NPSL

operations. The NPSL capital account shall include debit entries for all allowable direct and allocable joint costs incurred during the term of the lease, appropriate overhead allowances permitted on these costs pursuant to § 220.012, and allowances for capital recovery calculated pursuant to § 220.020. The NPSL capital account shall be credited with production revenues attributable to the NPSL and any other credits arising from NPSL activities.

(b) The NPSL capital account shall be kept on an accrual basis.

§ 220.011 Schedule of allowable direct and allocable joint costs and credits.

The costs and credits specified in paragraphs (a) through (p) of this section may be charged direct, or allocated to NPSL operations, as appropriate, in accordance with § 220.014.

(a) *Lease rental.* The rent paid by the lessee for the NPSL tract is allowable.

(b) *Labor.* (1)(i) Salaries and wages of lessee's field employees, first level supervisors and technical employees employed in the NPSL project area in NPSL operations are allowable if such costs are not charged under paragraph (g) of this section.

(ii) Salaries and wages of technical employees within technical branches of the lessee's organization who are either temporarily or permanently assigned to, and directly employed in NPSL operations are allowable provided that such employees work ''full time'' on some particular aspect of NPSL operations or some specific technical problem. Excluded from this category are employees assigned a role in NPSL operations as a duty collateral with other duties that do not directly benefit NPSL operations.

(iii) Salaries and wages of technical employees within technical branches of the lessee's organization who are assigned technical tasks directly related to NPSL operations may be allowable. Costs may be charged to the NPSL if supported by adequate time records showing the nature of the task and the hours spent on that task.

(2) Lessee's cost of allowed employee absence paid to employees whose salaries and wages are chargeable to NPSL operations under paragraphs (b)(1) (i) and (ii) of this section are allowable.

(3) Expenditures or contributions made pursuant to assessments imposed by governmental authority that are applicable to lessee's costs chargeable to NPSL operations under paragraphs (b)(1) (i) and (ii) and (b)(2) of this section are allowable.

(4) Reasonable personal expenses, including allowable relocation costs of employees whose salaries and wages are chargeable to NPSL operations under paragraphs (b)(1) (i) and (ii) of this section and that are paid by the lessee or for which the employees are reimbursed under the lessee's normal practice are allowable except as limited by § 220.013(g).

(i) Allowable relocation costs include:

(A) Travel expenses, including transportation, lodging, subsistence, and reasonable incidental expenses of the employee and members of his immediate family and transportation of his household and personal effects to the new location.

(B) Other necessary and reasonable expenses normally incident to relocation, such as costs of cancelling an unexpired lease, disconnecting and reinstalling household applicances, and purchases of insurance against damages to or loss of personal property are allowable. Costs of cancelling an unexpired lease shall not exceed three times the monthly rental.

(C) Closing costs (i.e. brokerage fees, legal fees, appraisal fees, etc.) for the sale of the employee's actual residence when notified of the transfer are allowable; and

(D) Continuing costs of ownership of the vacant former actual residence being sold, such as continuing mortgage principal and interest payments, maintenance of building and grounds (exclusive of fixing-up expenses), utilities, taxes, property insurance, etc., after settlement date of lease or date of new permanent residence are allowable.

(ii) The combined total of costs listed in paragraphs (b)(4)(i) (C) through (D) of this section shall not exceed 8 percent of the sales price of the property sold.

(iii) Section 220.013(g) specifies employee relocation expenses that are not allowable as a charge to NPSL operations.

(5) Lessee's current costs of established plans for employee's group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonds, and other benefit plans of a like nature that are made available to all of lessee's employees on an equitable basis, applicable to lessee's labor cost chargeable to NPSL operations under paragraphs (b)(1) (i) and (ii) and (b)(2) of this section, are allowable. The amount of these charges shall be lessee's actual cost not to exceed 23 percent of the total charges under paragraphs (b)(1) (i) and (ii) and (b)(2) except that the Director may from time to time establish a different maximum percentage.

(6) Charges for expenses incurred under paragraphs (b)(2) through (b)(5) of this section may be made to NPSL accounts on a ''when and as paid'' basis or by a percentage assessment method. If the percentage assessment method is used, it shall be based upon the lessee's actual cost experience expressed as a percentage of costs chargeable under paragraphs (b)(1) (i) and (ii) and (b)(2) of this section. Under either method the lessee's own cost of administering the plans and paying the salaries and benefits defined in this paragraph shall be excluded. In determining actual cost experience of an employee benefit plan, any dividend or refunds received that are applicable to insurance or annuity policies shall be used to reduce the cost of such policies.

(c) *Materiel.* (1) Materiel purchased or furnish by a lessee as NPSL property shall be charged or credited at amounts specified in § 220.015. The purchase and inventorying of materiel is subject to the conditions and provisions in § 220.032.

(2) Charges to an NPSL account shall be made only for such materiel purchased or furnished as NPSL property as is reasonably practical and consistent with efficient and economical operations. The accumulation of surplus stocks shall be avoided.

(3) Credit for salvaged or returned materiel shall be made to the NPSL capital account. When the amount originally charged qualifies for the allowance for capital recovery in § 220.020, the credit shall be calculated pursuant to § 220.021(a)(3).

(d) *Transportation.* Transportation of employees and materiel necessary for NPSL operations to, from, and within the NPSL project area, are allowable, but subject to the following limitations:

(1) If materiel is moved to the NPSL project area, no charge shall be made to NPSL operations for a distance greater than the distance from the nearest reliable supply store, recognized barge terminal, or railway receiving point where like materiel is normally available, unless agreed to by the Director.

(2) If surplus materiel is moved from the NPSL project area, no charge shall be made to NPSL operations for a distance greater than the distance to the nearest reliable supply store, recognized barge terminal, or railway receiving point unless agreed to by the Director. No charge shall be made to NPSL operations for moving materiel to other properties owned by or under the control of a lessee, unless agreed to by the Director.

(3) In the application of paragraphs (d)(1) and (d)(2) of this section, there shall be no equalization of actual gross trucking costs of $200 or less, excluding accessorial charges.

(e) *Contract services.* Except when excluded by paragraph (f) of this section and/or § 220.013(c), the cost of services and utilities provided under contract by outside parties to the lessee and which constitute proper and necessary NPSL operations or support for NPSL operations, and rental charges paid to outside parties for the use of equipment used in the NPSL project area in support of NPSL operations, may be charged to NPSL operations subject to the following conditions and limitations:

(1) Contract services (including professional consulting services and contract services of technical personnel) that are entirely performed in the NPSL project area and benefit exclusively NPSL operations may be charged at the rates specified in the contract.

(2) Contract services (including professional consulting services and contract services of technical personnel) that are entirely performed in the NPSL project area and benefit the NPSL operations and operations on other tracts must be allocated among all tracts benefited and only that portion representing services benefiting the NPSL tract charged to NPSL operations.

(3) Contract services (including professional consulting services and contract services of technical personnel) that are performed at sites outside the NPSL project area may be charged to NPSL operations only if:

(i) The contracted services charged to the NPSL operations benefit only the NPSL tract or support NPSL operations;

(ii) The contract under which such services are provided deals exclusively with services benefiting the NPSL tract or NPSL operations, or the costs of the contract services which are applicable to the NPSL tract or NPSL operations are separately and specifically identified in the contract; and

(iii) Services specified in the contract relate to the resolution of specific technical problems confronting NPSL operations, or specific engineering design problems related to equipment or facilities required for NPSL operations.

(4) The cost of any contract service related to research and development is specifically excluded, as are contract services calling for feasibility studies not directly related to specific engineering design problems or alternatives for equipment and facilities required by NPSL operations.

(f) *Legal expenses.* Expense of handling, investigating and settling litigation or claims, discharging of liens, payments of judgments and amounts paid for settlement of claims incurred in or resulting from NPSL operations, or necessary to protect or recover the NPSL property are allowable, except those costs listed in § 220.013(f) as unallowable. This includes the salaries and wages of lessee's legal staff and the expense of outside attorneys who are assigned to matters described in this paragraph if supported by adequate time records showing the nature of the matter, its direct relationship to NPSL operations, and the hours spent on the matter.

(g) *Rental of equipment and facilities furnished by lessee.* (1)(i) The NPSL capital account shall be charged for the use of equipment and facilities owned by a lessee that are proper and necessary for NPSL operations, including shore base and offshore facilities and pipelines from the tract to shore base production facilities, and that are not NPSL property. Rental charges shall be made at rates based upon actual costs of acquisition, construction, and operation. Such rates may include labor, the cost of setting up and dismantling equipment, maintenance, repairs, other operating expenses, insurance, taxes, depreciation (calculated using a method consistent with generally accepted accounting principles, consistently applied) and a return on the remaining undepreciated basis not to exceed 8 percent per year, except that the Director may from time to time establish a different maximum percentage. Any cost of acquiring real property in excess of that reasonably required to support the facilities furnished for NPSL operations shall not be included in the costs used to establish these rates. Rates charged shall not exceed average commercial rates for equipment and facilities of similar nature and capability currently prevailing in the vicinity of the NPSL project area.

(ii) The term *''equipment and facilities''* is used in the broad sense to include equipment that may be mobile or semimobile and also installations that may be semipermanent or permanent in nature. Such equipment and facilities listed below shall be charged on the basis indicated.

Equipment/facilities	Basis of charge
A. Mobile equipment:	
Aircraft	Hour.
Automobiles	Mile or hour.
Trucks	Mile or hour.
Tractors	Hour.
Bulldozers	Hour.
Mobile cranes	Hour.
Trailer-mounted test separators	Hour.
Truck-mounted cement mixers	Hour.
Boats	Day or hour.
House trailers	Day.
B. Semimobile equipment:	
Drill rigs	Foot or day.
Workover rigs	Hour.

Equipment/facilities	Basis of charge
Pulling units	Hour.
Derricks	Day.
Drilling tender	Day.
Barges	Day.
C. Semipermanent installations:	
Skid-mounted separators	Day or volume.
Skid-mounted compressors	Day or volume.
D. Permanent installations:	
Compressor stations	Volume.
Saltwater disposal wells	Volume or wells.
Source water wells and supply systems.	Volume.
Roads	Wells.
Production/drilling platform	Volume or wells.
Canals	Wells.
Dock	Wells.
Oil storage and loading facilities.	Volume.
Gathering systems and pipeline	Volume.
ACT systems	Volume.
Laboratory services (excluding research work).	Hour or unit.
Shore base production facilities	Volume.
Shore base support facilities	Wells.
E. Miscellaneous:	
Drill pipe	Foot or day.
Casing setting tools	Day.
Well testing equipment	Day.

Equipment and facilities that are not listed shall be charged on a basis consistent with the nature of the use.

(2) In lieu of charges in paragraph (g)(1) of this section, the lessee may elect to use average commercial rates prevailing in the vicinity of the NPSL project area less 20 percent. For automotive equipment, the lessee may elect to use rates established by the Director. For other equipment for which no commercial rate exists, the lessee shall submit the basis for determining such costs to the Director for approval.

(h) *Damages and losses to NPSL property.* All costs necessary for the repair or replacement of NPSL property made necessary because of damages or losses incurred by fire, flood, storm, theft, accident, or other causes not covered by insurance, except those resulting from lessee's negligence or willful misconduct may be charged to the NPSL capital account. Any settlement received from an insurance carrier should be credited to NPSL operations when received.

(i) *Taxes.* All taxes, except income taxes, profit share payments, and taxes based upon income, that are assessed or levied upon or in connection with NPSL operations and which have been paid by the lessee are allowable. Allowed taxes shall include, but not be limited to, production, severance, excise, ad valorem, and mineral taxes.

(j) *Insurance.* (1) Net premiums paid for insurance required to be carried for NPSL operations are allowable. For NPSL operations in which the lessee may act as self-insurer for Workmen's Compensation and Employer's Liability, the lessee may include the risk under its self-insurance program in providing coverage under State and Federal laws and charge NPSL operations at lessee's cost not to exceed manual rates.

(2) NPSL operations shall be credited for all reimbursements for costs of damage to NPSL property or personal injury. Reimbursements for damaged NPSL property shall be credited as follows:

(i) If the damaged NPSL property is replaced or repaired, to the NPSL capital account charged for the cost of replacement or repair; or

(ii) If the damaged NPSL property is not replaced or repaired, to the NPSL capital account except that if the cost of the property originally qualified for the allowance for capital recovery in § 220.020, the credit shall be calculated pursuant to § 220.021(a)(3).

(k) *Communications.* Costs of leasing, acquiring, installing, operating, repairing and maintaining communication systems, including radio, microwave facilities, and computer production controls for the NPSL operations are allowable. If communication facilities systems serving the NPSL tract serve operations and/or facilities outside the NPSL project area, charges to NPSL operations shall be made as provided in paragraph (g) of this section or shall be allocated to NPSL operations in accordance with § 220.014.

(l) *Ecological and environmental.* Costs incurred in the NPSL project area as a result of statutory regulations for archeological and geophysical surveys relative to identification and protection of cultural resources and other environmental or ecological surveys required by the Bureau of Land Management or other regulatory authority, may be charged to the NPSL capital account. Also, the costs to provide or have available pollution containment and removal equipment, including payments to organizations and/or funds which provide equipment and/or assistance in the event of oil spills or other

environmental damage are allowable. The costs of actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations are allowable, except that a charge shall not be allowed for any such costs attributable to the lessee's negligence or willful misconduct.

(m) *Dry or bottom hole contributions.* The costs of dry or bottom hole contributions made to obtain information about the structure or other characteristics of the geology underlying the NPSL tract are allowable.

(n) *Abandonment costs.* Actual costs incurred in the plugging of wells, dismantling of platforms and other facilities and in the restoration of the NPSL project area shall be charged to the NPSL capital account only when incurred (i.e., not on an accrual basis), except that costs incurred after the cessation of production shall not be charged to the NPSL capital account. Abandonment costs in excess of offsetting revenues shall not form the basis of any claim against the United States.

(o) *Other costs.* Any other costs not covered in paragraphs (a)–(n) of this section and not disallowed by § 220.013 that are incurred by the lessee in the necessary and proper conduct of NPSL operation and are approved by the Director, are allowable. Approval of a plan of development and production for the NPSL tract by the Director shall be considered sufficient approval for these other costs provided they are separately identified in said plan of development and production. Such separate identification shall note the nature of these other costs and may include an estimate of their magnitude. Any cost approvals under this paragraph for which the specific amounts have not been itemized are presumed to be approved provided they fall within the limits for a prudent operator. Approval of costs under this paragraph shall be approval solely for the purposes of determining allowable costs and shall not preclude a subsequent adjustment at audit of the amount of such costs.

(p) *Other credits.* Credit shall be given to the NPSL capital account, depending on when it is incurred, for NPSL property leased or used in non-NPSL operations, for the sale of information derived from test wells and G & G, and for any and all amounts earned or otherwise due lessee as a result of NPSL operations.

§ 220.012 Overhead allowance.

(a) During the capital recovery period the overhead allowance shall be calculated on a percentage basis at the rate of 4 percent of allowable direct and allocable joint costs charged to the NPSL capital account, exclusive of costs specified in paragraph (c) of this section. This overhead allowance shall be debited to the NPSL capital account in accordance with § 220.021(b)(2).

(b) For each month after the end of the capital recovery period, an overhead allowance shall be calculated on a percentage basis at the rate of 10 percent of allowable direct and allocable joint costs charged to the NPSL capital account, exclusive of costs specified in paragraph (c) of this section. This overhead allowance shall be debited to the NPSL capital account in accordance with § 220.021(c)(2).

(c) Overhead shall not be charged on the value of:

(1) Lease rental (§ 220.011(a));

(2) Contract services (§ 220.011(e));

(3) Taxes (§ 220.011(i));

(4) Re-injected hydrocarbons, originally produced from the NPSL tract, that are charged under § 220.011(c); and

(5) Credits for materiel charged under § 220.011(c) that are salvaged, returned, or used for the benefit of non-NPSL operations.

§ 220.013 Unallowable costs.

The following costs shall not be charged as direct or joint costs to NPSL operations:

(a) Bonus payments to the United States;

(b) Interest (except as permitted under § 220.011(g));

(c) Depreciation, depletion, amortization, or any other charge for capital recovery for materiel charged to the NPSL capital account under § 220.011(c), except as explicitly provided by the allowance for capital recovery calculated according to § 220.020;

(d) The cost of taking inventory;

(e) Research and development costs;

(f) The following legal expenses:

(1) The costs of litigation against the Federal government;

(2) Fines or penalties levied by any Federal agency;

(3) Settlement of claims or other litigation resulting from the lessee's violation of regulatory requirements or negligence; and

(4) The cost of the lessee's legal staff or expense of outside attorneys, except as explicitly allowed under § 220.011(f);

(g) The following employee relocation costs (whether incurred by the employee or the lessee):

(1) Loss on the sale of a home;

(2) Purchase price of a home in the new location;

(3) Payments for employee income taxes incident to reimbursed relocation costs; and

(4) Any relocation cost in connection with an employee move that is for the primary benefit of the lessee's non-NPSL operations;

(h) The lessee's own cost of administering employee benefit plans;

(i) The cost of acquiring or constructing shore base facilities and real property improvements that are charged to NPSL operations on a rental basis under § 220.011(g);

(j) Rentals on any facilities, the investment costs of which have been charged either directly or as allocable joint costs, to the NPSL capital account; and

(k) Pre-NPSL expenditures.

§ 220.014 Allocation of joint costs and credits.

(a) Joint costs shall be grouped in cost pools for allocation to NPSL and non-NPSL operations in reasonable proportion to the beneficial or causal relationships which exist between a specific cost pool and the operations. That portion of a joint cost pool that may be allocated to NPSL operations is called an allocable joint cost.

(b) The following allocation principles apply in allocating joint costs:

(1) *G & G.* G & G shall be allocated on a line mile per tract basis.

(2) *Wages and salaries.* Wages and salaries that are not charged as direct on the basis of time spent on a particular job shall be allocated on a reasonable and equitable basis.

(3) *Compensated personal absence, payroll taxes and personal expenses.* These items shall be allocated on the same basis as wages and salaries.

(4) *Transportation costs.* Transportation costs for employees that are not charged direct shall be allocated on the same basis as their wages and salaries.

(c) Joint credits shall be allocated in the same manner as joint costs.

(d) When the NPSL is made a part of a unit, the allowed costs shall be charged to the NPSL capital account on the basis specified in the unit operating agreement as approved by the Director. Revenues and other credits shall be made to the NPSL accounts on the same basis as specified in the approved operating agreement. Joint costs of an NPSL and a non-NPSL tract that are adjacent to one another and are on the same structure shall be allocated on a basis approved by the Director.

§ 220.015 Pricing of materiel purchases, transfers, and disposition.

(a)(1) *Purchased materiel.* Except as provided in paragraph (a)(2)(i) of this section, materiel purchased for use in NPSL operations shall be charged to NPSL operations at the price paid, after deduction of any discounts received. Should any purchased materiel be defective or returned to a vendor for other reasons, the credit shall be allocated to NPSL operations when received by the lessee in accordance with § 220.011(c)(3).

(2) *Transferred and disposal materiel.* An item of materiel, which is acquired by the lessee for use in NPSL operations by means other than purchase or disposed of by any means, shall be priced according to this subparagraph:

(i) *Condition A (new) materiel.* (A) Tubular goods, except line pipe, shall be priced at the current market price in effect on date of movement on a minimum carload or barge load weight basis, regardless of quantity transferred, equalized to the lowest published price ''free on board'' (f.o.b.) railway receiving point or recognized barge terminal nearest the NPSL tract where such materiel is normally available.

(B) *Line pipe. (1)* Movement of less than 30,000 pounds shall be priced at the current price in effect at date of

movement, as listed by a reliable supply store nearest the NPSL tract where such materiel is normally available.

(2) Movement of 30,000 pounds or more shall be priced under the provisions for tubular goods pricing in paragraph (a)(2)(i)(A) of this section.

(C) Other materiel shall be priced at the current price in effect at date of movement, as listed by a reliable supply store or f.o.b. railway receiving point nearest the NPSL tract where such materiel is normally available.

(ii) *Condition B (good used) materiel.* Materiel in sound and serviceable condition and suitable for reuse without reconditioning:

(A) Materiel transferred to the NPSL project area shall be priced at 75 percent of current Condition A price.

(B) Materiel transferred from the NPSL project area shall be priced:

(1) At 75 percent of current Condition A price, if the materiel was originally charged to NPSL operations as Condition A materiel, or

(2) At 65 percent of current Condition A price, if the materiel was originally charged to NPSL operations as Condition B materiel at 75 percent of current Condition A price.

(iii) *Conditions C and D (other used) materiel*—(A) *Condition C.* Materiel that is not in sound and serviceable condition and not suitable for its original function until after reconditioning shall be priced at 50 percent of current Condition A price.

(B) *Condition D.* Materiel no longer suitable for its original purposes but suitable for some other purpose shall be priced on a basis commensurate with its use and comparable with that of materiel normally used for such other purpose. If the materiel has no alternative use it should be priced at prevailing prices as scrap.

(iv) *Obsolete materiel.* Materiel that is serviceable and usable for its original function and has a value less than Condition A, B, or C materiel may be valued at a price agreed to by the Director. Such price should be the equivalent of the value of the service rendered by such materiel.

(b) *Pricing conditions.* (1) Loading and unloading costs shall be charged at a rate of 15 cents per hundred weight, or such other rate as may be set by the Director, on all tubular goods movements, in lieu of loading/unloading costs sustained, when the actual hauling costs of such tubular goods is equalized under provisions of § 220.011(d).

(2) Materiel involving erection costs shall be charged at the applicable percentage of the current knocked-down price of new materiel.

(c) When materiel subject to paragraphs (a)(2) (ii) and (iii) of this section is transferred, the cost of reconditioning shall be borne by the receiving party.

§ 220.020 Calculation of the allowance for capital recovery.

(a) For purposes of this section, the cost base for the allowance for capital recovery in a particular month shall consist of the sum of:

(1) All allowable direct and allocable joint costs chargeable to the NPSL capital account during the month less any costs specified in § 220.012(c); plus

(2) The value of contract services chargeable to the NPSL capital account during the month pursuant to § 220.011(e); plus

(3) The capital recovery period overhead allowance, calculated in accordance with § 220.012(a), that is chargeable to the NPSL capital account for the month; less

(4) Production revenues and other credits received during the month.

(b) If the cost base for a month is greater than zero (that is, if the sum of the charges specified in paragraphs (a)(1) through (3) of this section exceeds the value of production revenues and other credits), the allowance for capital recovery shall be calculated by multiplying the cost base by the capital recovery factor, and shall be debited to the NPSL capital account as specified in § 220.021(b).

(c) If the cost base for a month is less than zero, the allowance for capital recovery for the NPSL capital account shall be calculated by multiplying the resulting negative cost base by the capital recovery factor. The negative product of this calculation shall be debited to the NPSL capital account as specified in § 220.021(b).

(d) No allowance for capital recovery shall be calculated on the charges or

credits related to any time period after the end of the capital recovery period.

§ 220.021 Determination of net profit share base.

(a) During each month of the lease term, the NPSL capital account shall be:

(1) Debited with allowable direct and allocable joint costs;

(2) Credited with an amount reflecting the production revenues for the month, calculated in accordance with § 260.110(b) of this chapter.

(3) Credited with amounts properly credited back to the NPSL capital account as specified in § 220.011(p). Credits associated with charges to the NPSL capital account during the capital recovery period, however, shall first be increased by the value of the credit multiplied by the recovery factor, before crediting that sum to the NPSL capital account.

(b) At the end of each month of the lease term during the capital recovery period:

(1) The transactions specified in paragraph (a) of this section shall be made to the NPSL capital account.

(2) The capital recovery period overhead allowance shall be calculated in accordance with § 220.012(a) and debited to the NPSL capital account.

(3) The allowance for capital recovery shall be calculated in accordance with § 220.020 and the allowance debited (or the negative allowance debited, as appropriate) to the NPSL capital account. (A debit entry of a negative allowance for capital recovery shall have the same effect as a credit entry of the absolute value of the allowance for capital recovery.)

(4) The balance in the NPSL capital account shall be calculated. If, as a result of the accounting transactions described in paragraphs (b) (1) through (3) of this section, there is a credit balance in the NPSL capital account, the capital recovery period will be considered terminated as of this month. The credit balance will be forwarded to the next month, which will be the first month for which a profit share payment is due.

(c) At the end of each month of the lease term following the end of the capital recovery period:

(1) The transaction specified in paragraph (a) of this section shall be made to the NPSL capital account.

(2) An overhead allowance shall be calculated in accordance with § 220.012(b) and debited to the NPSL capital account.

(3) The balance in the NPSL capital account shall be calculated.

(d) If, as a result of the accounting transactions described in paragraph (c) of this section, there is a credit balance in the NPSL capital account, this credit balance is the net profit share base for that month. The opening debit and credit balances in the NPSL capital account for any month following a month in which there is a credit balance in the NPSL capital account (except as provided in paragraph (b)(4)) of this section shall be zero.

(e) If, as a result of the accounting transactions described in paragraph (b) or (c) of this section, there is a debit balance in the NPSL capital account, this debit balance shall be the opening debit balance in the NPSL capital account for the following month.

(f) Any credit balance in the NPSL capital account shall become the net profit share base as described in this section. Any debit balance in the NPSL capital account shall be maintained only insofar as necessary for the determination of profit share payments. Such debit balance shall not represent a claim against the United States.

[45 FR 36800, May 30, 1980. Redesignated at 48 FR 1182, Jan. 11, 1983, and at 48 FR 35642, Aug. 5, 1983, and amended at 55 FR 1210, Jan. 12, 1990]

§ 220.022 Calculation of net profit share payment.

The net profit share payment shall be calculated by multiplying the net profit share base calculated in accordance with § 220.021 by the net profit share rate. The net profit share payment shall be paid to the United States in accordance with § 220.031.

§ 220.030 Maintenance of records.

(a) Each lessee subject to this part 220 shall establish and maintain such records as are necessary to determine for each NPSL:

(1) The volume and disposition of all oil and gas production saved, removed or sold for each month;

(2) The value of all oil and gas production saved, removed or sold for each month;

(3) The amount and description of costs and credits to the NPSL capital account;

(4) The amount and description of all costs of acquisition, construction, and operation of equipment and facilities furnished by the lessee and charged to the NPSL capital account under § 220.011(g). Such records shall include worksheets or other documents that indicate the method used to calculate the amount of each charge made under § 220.011(g);

(5) The cumulative balance of costs and credits to the NPSL capital account; and

(6) The inventory of materiel.

(b) The ledger cards showing the charges and credits to the NPSL capital account shall be maintained until thirty-six months after the cessation of NPSL operations by the lessee. All other documents, journals and records shall be maintained for thirty-six months from the due date or date of mailing of the statement of account on an NPSL, whichever comes later, except that nothing in these regulations shall limit the time of investigation or the need to produce records when prima facie evidence of fraud or willful misconduct is obtained with respect to the government's interest in the NPSL.

§ 220.031 Reporting and payment requirements.

(a) Each lessee subject to this part shall file an annual report during the period from issuance of the NPSL until the first month in which production revenues are credited to the NPSL capital account. Such report shall list the costs incurred, including allowances applied, credits received, and the balance of the NPSL capital account. Not later than 60 days after the end of the first month in which production revenues are credited to the NPSL capital account, a final report relating to the period shall be filed.

(b) Beginning with the first month in which production revenues are credited to the NPSL capital account, each lessee subject to this part 220 shall file a report for each NPSL, not later than 60 days following the end of each month, containing the following information for the month for which the report is filed:

(1) The volume and disposition of all oil and gas production saved, removed or sold;

(2) The production revenue;

(3) The amount and description of all costs and credits to the NPSL capital account;

(4) The balance of the NPSL capital account; and

(5) The net profit share base and net profit share payment due the United States and the monthly profit share of the lessee.

(c) Each lessee subject to this part 220 shall submit, together with the report required by paragraph (b) of this section, any net profit share payment due the United States for the period covered by the report.

(d) Each lessee subject to this part 220 shall file a report not later than 90 days after each inventory is taken, reporting the controllable materiel on hand, acquired, transferred or used.

(e) Each lessee subject to this part 220 shall file a final report, not later than 60 days following the cessation of production, together with the appropriate net profit share payment, indicating the remaining balance and costs and credits to the NPSL capital account for the period.

(f) Reports required by this section shall be filed with the Director, either separately or as part of the reports that are currently filed.

(g) Interest shall be calculated at the prevailing rate or rates as published in the Bulletin to the Department of the Treasury Fiscal Requirement Manual, in effect for the period or periods over which the net profit share payment is owed, compounded monthly, on the amount of a net profit share payment, from the due date (60 days following the end of each month for which the payment was due) of a net profit share payment until such payment is received by the United States.

§ 220.032 Inventories.

(a) The lessee is responsible for NPSL materiel and shall make proper and

timely cost and credit notations for all materiel movements affecting NPSL property. The lessee shall provide only such materiel as may be required for immediate use or is consistent with practical, efficient, and economical operations. The accumulation of surplus stocks shall be avoided by proper materiel control, inventory and purchasing. The lessee shall make timely disposition of idle and surplus materiel through sale.

(b) At reasonable intervals, but at least once every three years, inventories of controllable materiel shall be taken by the lessee. Written notice of intention to take inventory shall be given by the lessee at least 30 days before any inventory is to be taken so that the Director may be represented at the taking of inventory. Failure of the Director to be represented at an inventory shall bind the Director to accept the inventory taken by the lessee, except in the case of willful misrepresentation or fraud.

(c) Inventory shall be valued with any generally accepted accounting method used by the lessee to value the same materiel for financial or income tax reporting purposes, provided that the method is consistently applied throughout the life of the materiel.

(d) Reconciliation shall be made of a physical inventory with the NPSL capital account by the lessee, and a list of overages and shortages shall be available to the Director for audit as provided in § 220.033. Inventory adjustments of controllable materiel shall be made by the lessee to the NPSL capital account for overages and shortages. Controllable materiel removed from physical inventory that has not been credited to NPSL operations under § 220.015(a)(2) shall be credited to NPSL operations at its original value, except that when the cost of the materiel originally qualified for the allowance for capital recovery in § 220.020, the credit shall be calculated pursuant to § 220.021(a)(3).

§ 220.033 Audits.

(a) The accounts of an NPSL lessee or of a contractor of the lessee which are related to NPSL operations shall be subject to audit by DOI or its appointed agent. Where possible, the auditor for DOI shall coordinate audit efforts with other nonoperators, if any. DOI shall have the right to initiate an audit any time within thirty-six months of the due date of the monthly statement that is to be audited or the date that the statement was mailed, whichever is later, provided, however, that audits may not be conducted any more frequently than once every year except upon a showing of fraud or willful misrepresentation.

(b)(1) When nonoperators of an NPSL lease call an audit in accordance with the terms of their operating agreement, the Director shall be notified of the audit call in the same manner as the operator is notified. DOI may elect to send an auditor with the audit team specified by the nonoperators in lieu of calling for a separate audit by DOI.

(2) If DOI determines to call for an audit, DOI shall notify the lessee of its audit call and set a time and place for the audit. Such a notice shall be sent at least thirty days before the suggested time for the audit to allow the nonoperators to join in DOI's audit in lieu of calling for their own audit. The place for the audit will normally be the place where the lessee maintains its records pertaining to the NPSL lease. The lessee shall send copies of the notice to the nonoperators on the lease. The lessee shall use reasonable effort to notify all nonoperators, but failure to include one or more nonoperators in the notification shall not void the notice.

(3) When DOI calls for an audit, DOI may suggest the date and time when the audit may commence. The estimated duration of the audit may be mentioned to the lessee as well as to the other nonoperators who may elect to supply and auditor for their own audit purposes. The lessee's office where the audit will be held may be named or, if not known, inquired about. If a visit to a field plant or field office is contemplated by the government auditor, such a field trip may be mentioned. If DOI expresses a desire to review a period on which the thirty-six month time limitation has expired, it is the lessee's prerogative to allow the review or to request that DOI adhere to the time limitation specified in these regulations.

(c)(1) Exceptions to the accounting by the lessee, whether in favor of the government or the lessee, shall be noted in a report to the lessee. The lessee shall have 60 days from the mailing of a notice of exceptions to agree to the adjustments proposed by the DOI auditor or to object to the proposed adjustments. If the lessee accepts the proposed adjustments, the adjustment shall be booked in the month in which the lessee agrees to the adjustment, except where such adjustment would have resulted in a change in any net profit share payment due the United States. In such a case, there shall be a redetermination of the NPSL capital account pursuant to § 220.034.

(2) If the lessee disagrees with the adjustment, the lessee shall have the right to appeal the adjustment to the Director.

(d) Upon receipt of an agreement by the government auditor that there are no required audit adjustments, upon final determination with respect to any audit adjustment proposed by the government auditor, or upon the lapse of thirty-six months from the due date or date of mailing of the statement of account on an NPSL lease, whichever comes later, the books shall be closed for audit adjustment purposes, except upon a showing of fraud or willful misrepresentation.

(e) Records required to be kept under § 220.030(a) shall be made available for inspection by any authorized agent of DOI at any time during normal business hours upon the request of the Director or other authorized official.

§ 220.034 Redetermination and appeals.

(a) If, as a result of an inspection of records or an audit under § 220.033, the Director determines that there is an error in the NPSL capital account or an error in calculating the net profit share payment, whether in favor of the government or the lessee, the Director shall redetermine the net profit share base and recalculate the net profit share payment due the United States and notify the lessee of the recalculation.

(b) The lessee shall pay any additional amount of net profit share payment owed plus interest, compounded monthly, from the date that the payment was due until the date it is actually paid. Interest shall be calculated at the prevailing rate or rates as published in the Bulletin to the Department of the Treasury Fiscal Requirements Manual, in effect for the period or periods over which the payment is owed.

(c) If the recalculated profit share payment is less than the amount paid the United States, the lessee shall apply such overpayment to the next profit share payment.

(d) Within 30 days after receiving notice of the recalculation as provided in paragraph (a) of this section, the lessee may appeal the decision of the Director in accordance with the appeals provision of 30 CFR part 290.

PART 228—COOPERATIVE ACTIVITIES WITH STATES AND INDIAN TRIBES

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228.104 Availability of information.
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228.107 Eligible cost of activities.
228.108 Deduction of civil penalties accruing to the State or tribe from the Federal share of a cooperative agreement.

AUTHORITY: Section 202, Pub. L. 97–451, 96 Stat. 2457 (30 U.S.C. 1732).

SOURCE: 49 FR 37348, Sept. 21, 1984, unless otherwise noted.

Subpart A—General Provisions

§ 228.1 Purpose.

It is the purpose of cooperative agreements to effectively utilize the capabilities of the States and Indian

tribes in developing and maintaining an efficient and effective Federal royalty management system as indicated at 30 U.S.C. 1701.

§ 228.2 Policy.

It shall be the policy of DOI to enter into cooperative agreements with States and Indian tribes to carry out audits and related investigations and enforcement actions whenever a State or tribe initiates a request to enter into an agreement and a finding is made that a State or tribe has the ability to carry out cooperative activities in a timely and efficient manner.

§ 228.4 Authority.

The Secretary of the Interior is authorized to enter into cooperative agreements with States and Indian tribes (30 U.S.C. 1732) to share oil or gas royalty management information, and to carry out auditing and related investigation or enforcement activities in cooperation with the Secretary.

§ 228.5 Delegation of authority.

(a) Authority to enter into cooperative agreements to carry out audit and related investigation and enforcement activities with State and tribal governments has been delegated to the Director of the Minerals Management Service (MMS).

(b) Authority to enter into cooperative agreements with State and tribal governments to carry out inspection and related investigation and enforcement activities has been delegated to the Director of the Bureau of Land Management (BLM) and is not covered by this part.

(c) The entry into a cooperative agreement with either MMS or BLM will not affect the ability of a State or Indian tribe to choose to enter into such an agreement with the other agency. A State may enter into a delegation agreement (30 U.S.C. 1735) with MMS to perform certain functions without affecting its ability to enter into a cooperative agreement with either MMS or BLM, or both, to cooperate in the performance of those functions which are not delegated in this part.

§ 228.6 Definitions.

For the purposes of this part, terms shall have the same meaning as in 30 U.S.C. 1702. In addition, the following definition shall apply:

Audit means an examination of the financial accounting and lease related records of the lessee and other interest holders, who by lease or contract pay royalties or are obligated to pay royalties, rents, bonuses or other payments on Federal or Indian leases. An examination is to be conducted in accordance with generally accepted audit standards as adopted by the American Institute of Certified Public Accountants. Activities to be examined which are considered to be an audit function include reconciliation of lease accounts under the Royalty Accounting System; records of lease activities related to Federal leases located within the boundaries of the State entering into a cooperative agreement; records of lease activities related to leases located on Indian lands, and the review and resolution of exceptions processed by the Auditing and Financial System and the Production Accounting and Auditing System, the official accounting systems for royalty reporters and payors maintained by the MMS.

§ 228.10 Information collection.

(a) The information collection requirements contained in this part have been approved by OMB under 44 U.S.C. 3501 et seq. and assigned OMB Clearance Number 1010–0087. The information collected will be used to prepare a cooperative agreement with a State or Indian tribe wishing to perform royalty audits. The information should be submitted voluntarily in order to enter into a cooperative agreement authorized by 30 U.S.C. 1732.

(b) Public reporting burden is estimated to average 136 hours for the preparation of the original request for consideration and application to enter into a cooperative agreement. Subsequent requests for renewal of the agreement may require about 40 hours for the preparation of an annual budget and work plan, and an estimated 8 hours per quarter for preparation of a reimbursement voucher and an audit progress report. Send comments regarding this burden estimate or any

other aspect of this collection of information, including suggestions for reducing burden, to the Information Collection Clearance Officer, Minerals Management Service, 381 Elden Street, Herndon, Virginia 22070; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project 1010–0087, Washington, DC 20503.

[57 FR 41868, Sept. 14, 1992, as amended at 58 FR 64903, Dec. 10, 1993]

Subpart B—Oil and Gas, General [Reserved]

Subpart C—Oil and Gas, Onshore

§ 228.100 Entering into an agreement.

(a) A State or Indian tribe may request the Department to enter into a cooperative agreement by sending a letter from the governor, tribal chairman, or other appropriate official with delegation authority, to the Director of MMS.

(b) The request for an agreement shall be in a format prescribed by MMS and should include at a minimum the following information:

(1) Type of eligible activities to be undertaken.

(2) Proposed term of the agreement.

(3) Evidence that the State or Indian tribe meets, or can meet by the time the agreement is in effect, the standards established by the Secretary for the types of activities to be conducted under the terms of the agreement.

(4) If the State is proposing to undertake activities on Indian lands located within the State, a resolution from the appropriate tribal council indicating their agreement to delegate to the State responsibilities under the terms of the cooperative agreement for activities to be conducted on tribal or allotted land.

(c) The eligible activities to be conducted under the terms of a cooperative agreement may be funded or unfunded by the Department. See § 228.105 of this subpart for funding of cooperative agreements.

[49 FR 37348, Sept. 21, 1984, as amended at 56 FR 10512, Mar. 13, 1991]

§ 228.101 Terms of agreement.

(a) Agreements entered into under this part shall be valid for a period of 3 years and shall be renewable or additional consecutive 3-year periods upon request of the State or Indian tribe which is a party to the agreement.

(b) An agreement may be terminated at any time by mutual agreement and upon any terms and conditions as agreed upon by the parties.

(c) A State or Indian tribe may unilaterally terminate an agreement by giving a 120-day written notice of intent to terminate.

(d) The MMS may commence termination of an agreement by giving a 120-day written notice of intent to terminate. MMS shall provide the State or Indian tribe with the reasons for the proposed termination in writing if the termination is proposed because of alleged deficiencies by the State or Indian tribe in carrying out the provisions of the agreement. The State or Indian tribe will be given 60 days to respond to the notice of deficiencies and to provide a plan for correction of those deficiencies. No final action on termination shall be taken until any submission of the State or Indian tribe provided within the above prescribed 60 days has been reviewed by MMS for content or merit.

(e) Termination of a cooperative agreement shall not bar a later request by a State or Indian tribe to enter into a subsequent cooperative agreement.

§ 228.102 Establishment of standards.

The MMS, after consultation with States and Indian tribes, shall establish standards for carrying out the activities under the provisions of this part. The standards will be incorporated into the agreement and shall be no more stringent than those applicable to similar activities of the MMS. The States and Indian tribes shall coordinate their planned auditing activities with MMS. Where an MMS audit team is permanently assigned to a lessee/payor, contact by State and Indian tribal auditors with the lessee/payor shall be through the MMS auditor in residence.

§ 228.103 Maintenance of records.

(a) The State or Indian tribe entering into a cooperative agreement under this part must retain all records, reports, working papers, and any backup materials for a period specified by MMS. All records and support materials must be available for inspection and review by appropriate personnel of the Department including the Office of the Inspector General.

(b) The State or Indian tribe shall maintain all books and records as may be necessary to assure compliance with the provisions of chapter 1, 48 CFR 31.107 and 48 CFR subpart 31.6 (Contracts with State, local, and federally recognized Indian tribal Governments).

[56 FR 10512, Mar. 13, 1991]

§ 228.104 Availability of information.

(a) Under the provisions of this part, information necessary to carry out the activities authorized under the terms of a cooperative agreement will be provided by DOI to the States and Indian tribes entering into such agreements. The information will consist of data provided from all relevant sources on a lease level basis for leases located within the boundaries of the State or Indian tribe which has entered into the agreement. This information will include any records or data held by the lessee or other person that have not been submitted to MMS, but that affect Federal lease interests and could be required to be submitted under the lease terms or Federal regulations.

(b) None of the provisions of this subpart should be construed as limiting information already being provided to Indian tribes and allottees regarding their lease interests.

(c) Information will be provided by MMS on a monthly basis and will include data on royalties, rents, and bonuses collected on the lease, volumes produced, sales made, value of products disposed of as a sale and used as a basis for royalty calculation, and other information necessary to allow the State or tribe to carry out its responsibilities under the cooperative agreement.

(d) Proprietary data that is made available to a State or tribe under provisions of 30 U.S.C. 1733 shall be subject to the constraints of 18 U.S.C. 1905. To receive proprietary data, the State or tribe must—

(1) Demonstrate what audit, investigation, or litigation under provisions of 30 U.S.C. 1734 is planned for or underway for which this data is essential;

(2) Demonstrate why this particular data is necessary; and

(3) Agree to safeguard proprietary data as provided.

§ 228.105 Funding of cooperative agreements.

(a)(1) The Department may, under the terms of the cooperative agreement, reimburse the State or Indian tribe up to 100 percent of the costs of eligible activities. Eligible activities will be agreed upon annually upon the submission and approval of a workplan and funding requirement.

(2) A cooperative agreement may be entered into with a State or Indian tribe, upon request, without a requirement for reimbursement of costs by the Department.

(b) All cooperative agreements under this part are subject to annual funding and the availability of appropriations specifically designated for the purpose of this part.

(c) The State or Indian tribe shall submit a voucher for reimbursement of eligible costs incurred within 30 days of the end of each calendar quarter. The State or Indian tribe must provide the Department a summary of costs incurred, for which the State or Indian tribe is seeking reimbursement, with the voucher.

[49 FR 37348, Sept. 21, 1984, as amended at 56 FR 10512, Mar. 13, 1991]

§ 228.107 Eligible cost of activities.

(a) If a cooperative agreement provides for Federal funding, only costs directly associated with eligible activities undertaken by the State or Indian tribe under the terms of a cooperative agreement will be eligible for reimbursement. Costs of services or activities which cannot be directly related to the support of activities specified in the agreement will not be eligible for Federal funding or for inclusion in the State's share or in the Indian tribe's share of funding that may be established in the agreement.

(b) Eligible costs are the cost of salaries and benefits associated with technical, support, and clerical personnel engaged in eligible activities; direct cost of travel, rentals, and other normal administrative activities in direct support of the project or projects; basic and specialized training for State and tribal participants; and cost of any contractual services which can be shown to be in direct support of the activities covered by the agreement. Each cooperative agreement shall contain detailed schedules identifying those activities and costs which qualify for funding and the procedures, timing, and mechanics for implementing Federal funding.

[49 FR 37348, Sept. 21, 1984, as amended at 56 FR 10512, Mar. 13, 1991]

§ 228.108 Deduction of civil penalties accruing to the State or tribe from the Federal share of a cooperative agreement.

As provided at 30 U.S.C. 1736, 50 percent of any civil penalty collected as a result of activities under a cooperative agreement will be shared with the State or Indian tribe performing the cooperative agreement; however, the amount of the civil penalty shared will be deducted from any Federal funding owed under that cooperative agreement. MMS shall maintain records of civil penalties collected and distributed to the States and tribes involved in cooperative agreements. Each quarterly payment of the Federal share of a cooperative agreement will be reduced by the amount of the civil penalties paid to the State or tribe during the prior quarter.

PART 229—DELEGATION TO STATES

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AUTHORITY: Section 205, Pub. L. 97–451, 96 Stat. 2459 (30 U.S.C. 1735).

Subpart A—General Provisions

SOURCE: 49 FR 37350, Sept. 21, 1984, unless otherwise noted.

§ 229.1 Purpose.

The purpose of this part is to promote the effective utilization of the capabilities of the States in developing and maintaining an efficient and effective Federal royalty management system.

§ 229.2 Policy.

It shall be the policy of the Department of the Interior (DOI) to honor any properly made petition from the Chief Executive or other appopriate official

of a State seeking delegation of authority under the provisions of 30 U.S.C. 1735 and to make a delegation to conduct audits and related investigations when the Secretary finds that the provisions of 30 U.S.C. 1735 have been complied with or can be complied with by a State seeking the delegation.

§ 229.4 Authority.

The Secretary of the DOI is authorized under provisons of 30 U.S.C. 1735 to delegate authority to States to conduct audits and related investigations with respect to all Federal lands within a State, and to those Indian lands to which a State has received permission from the respective Indian tribe(s) or allottee(s) to carry out audit activities under a delegation from the Secretary.

§ 229.6 Definitions.

The definitions contained in 30 U.S.C. 1702 and in part 228 of this chapter apply to the activities carried out under the provisions of this part.

§ 229.10 Information collection requirements.

The information collection requirements contained in this part do not require approval by the Office of Management and Budget under 44 U.S.C. 3501 *et seq.*, because there are fewer than 10 respondents annually.

Subpart B—Oil and Gas, General [Reserved]

Subpart C—Oil and Gas, Onshore

AUTHORITY: The Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 *et seq.*).

ADMINISTRATION OF DELEGATIONS

§ 229.100 Authorities and responsibilities subject to delegation.

(a) All or part of the following authorities and responsibilities of the Secretary under the Act may be delegated to a State authority:

(1) Conduct of audits related to oil and gas royalty payments made to the MMS which are attributable to leased Federal or Indian lands within the State. Delegations with respect to any Indian lands require the written permission, subject to the review of the MMS, of the affected Indian tribe or allottee.

(2) Conduct of investigations related to oil and gas royalty payments made to the MMS which are attributable to leased Federal lands or Indian lands within the State. Delegation with respect to any Indian lands require the written permission, subject to the review of the MMS, of the affected Indian tribe or allottee. No investigation will be initiated without the specific approval of the MMS or the Secretary's designee and in accordance with the Departmental Manual.

(b) The following authorities and responsibilities are specifically reserved to the MMS and are not delegable under these regulations:

(1) Enforcement actions to assess and collect additional royalties identified as a consequence of audits, inspections, and investigations. These include all actions related to resolution of royalty obligations so identified, and the establishment and maintenance of payment performance bonds which may be required during the resolution process.

(2) Enforcement actions to collect civil penalties and interest charges related to findings of audits, inspections, and investigations.

(3) Administration of all appeals and all actions of the Department related to administrative and judicial litigation.

(4) Issuance of subpoenas.

(c) The provisions of this section do not limit the authority provided to the States by section 204 of the Act.

[49 FR 40026, Oct. 12, 1984]

§ 229.101 Petition for delegation.

(a) The governor or other authorized official of any State which contains Federal oil and gas leases, or Indian oil and gas leases where the Indian tribe and allottees have given the State an affirmative indication of their desire for the State to undertake certain royalty management-related activities on their lands, may petition the Secretary to assume responsibilities to conduct audits and related investigations of royalty related matters affecting Federal or Indian oil and gas leases within the State.

(b) A State may enter into a delegation of authority under this part without affecting a State's ability to enter into a cooperative agreement under Part 228 of this chapter.

(c) The Secretary shall carry out all factfinding and hearings he may decide are necessary in order to approve or disapprove the petition.

(d) In the event that the Secretary denies the petition, the Secretary must provide the State with the specific reasons for denial of the petition. The State will then have 60 days to either contest or correct specific deficiencies and to reapply for a delegation of authority.

[49 FR 37350, Sept. 21, 1984. Redesignated and amended at 49 FR 40025, Oct. 12, 1984]

§ 229.102 Fact-finding and hearings.

(a) Upon receipt of a petition for delegation from a State, the Secretary shall appoint a representative to conduct a hearing or hearings to carry out factfinding and determine the ability of the petitioning State to carry out the delegated responsibilities requested in accordance with the provisions of this part.

(b) The Secretary's representative, after proper notice in the FEDERAL REGISTER and other appropriate media within the State, shall hold one or more public hearings to determine whether:

(1) The State has an acceptable plan for carrying out delegated responsibilities and if it is likely that the State will provide adequate resources to achieve the purposes of this part (30 U.S.C. 1735);

(2) The State has the ability to put in place a process within 60 days of the grant of delegation which will assure the Secretary that the functions to be delegated to the State can be effectively carried out;

(3) The State has demonstrated that it will effectively and faithfully administer the rules and regulations of the Secretary in accordance with the requirements at 30 U.S.C. 1735;

(4) The State's plan to carry out the delegated authority will be in accordance with the MMS standards; and

(5) The State's plan to carry out the delegated authority will be coordinated with MMS and the Office of Inspector General audit efforts to eliminate added burden on any lessee or group of lessees operating Federal or Indian oil and gas leases within the State.

(c) A State petitioning for a delegation of authority shall be given the opportunity to present testimony at a public hearing.

[49 FR 37350, Sept. 21, 1984. Redesignated and amended at 49 FR 40025, Oct. 12, 1984]

§ 229.103 Duration of delegations; termination of delegations.

(a) Delegations of authority shall be valid for a period of 3 years and may be renewable for an additional consecutive 3-year period upon request of the State and after the appropriate factfinding required in § 229.101. Delegations are subject to annual funding and the availability of appropriations specifically designated for the purpose of this part.

(b) A delegation of authority may be terminated at any time and upon any terms and conditions as mutually agreed upon by the parties.

(c) A State may terminate a delegation of authority by giving a 120-day written notice of intent to terminate.

(d) The Department may terminate a delegation of authority when it is determined, after opportunity for a hearing, that the State has failed to substantially comply with the provisions of the delegation of authority.

(e) No action to initiate formal hearing proceedings for termination shall be taken until the Department has notified the State in writing of alleged deficiencies and allowed the State 120 days to correct the deficiencies.

(f) Termination of a delegation shall not bar a subsequent request by a State to regain a delegation of authority.

[49 FR 37351, Sept. 21, 1984, as amended at 49 FR 40025, Oct. 12, 1984]

§ 229.104 Terms of delegation of authority.

Each delegation of authority under this part shall be in writing, shall incorporate all the requirements of this part, and shall specifically include:

(a) Terms obligating the State to conduct audit and investigative activities for a specific period of time;

(b) Terms describing the authorities and responsibilities reserved by the

MMS, including, but not limited to, those specified under § 229.100;

(c) Terms requiring the State to provide annual audit workplans to include the lease universe by company, or by individual lease accounts, a description of the audit work product(s) to be delivered, and the State resources (staff and otherwise) to be committed to the delegation;

(d) Terms requiring the State to notify the MMS of any changed circumstances which would affect the State's ability to carry out the terms of the delegation;

(e) Terms requiring coordination of delegated activities among the State, the MMS, and the land management agencies responsible for management of the leases included in the audit universe;

(f) Terms requiring the State to maintain and make available to the MMS all audit workpapers, documents, and information gained or developed as a consequence of activities conducted under the delegation;

(g) Terms obligating the State to adhere to all Federal laws, rules and regulations, and Secretarial determinations and orders relating to the calculation, reporting, and payment of oil and gas royalties, in all activities performed under the delegation.

[49 FR 40026, Oct. 12, 1984]

§ 229.105 Evidence of Indian agreement to delegation.

In the case of a State seeking a delegation of authority for Indian lands as well as Federal lands, the State petition to the Secretary must be supported by an appropriate resolution or resolutions of tribal councils joining the State in petitioning for delegation and evidence of the agreement of individual Indian allottees whose lands would be involved in a delegation. Such evidence shall specifically speak to having the State assume delegated responsibility for specific functions related to royalty management activities.

[49 FR 37351, Sept. 21, 1984. Redesignated at 49 FR 40025, Oct. 12, 1984]

§ 229.106 Withdrawal of Indian lands from delegated authority.

If at any time an Indian tribe or an individual Indian allottee determines that it wishes to withdraw from the State delegation of authority in relation to its lands, it may do so by sending a petition of withdrawal to the State. Once the petition has been received, the State shall within 30 days cease all activities being carried out under the delegation of authority on the lands covered by the petition for the tribe or allottee.

[49 FR 37351, Sept. 21, 1984. Redesignated at 49 FR 40025, Oct. 12, 1984]

§ 229.107 Disbursement of revenues.

(a) The additional royalties and late payment charges resulting from State audit work done under a delegation of authority shall be collected by MMS. The State's share of any amounts so collected shall be paid to the State in accordance with the provisions of 30 U.S.C. 191 and part 219 of this chapter.

(b) Amounts collected for Indian leases shall be transferred to the appropriate Indian accounts (designated Treasury accounts) managed by the Bureau of Indian Affairs at the earliest practicable date after such funds are received, but in no case later than the last business day of the month in which such funds are received.

(c) MMS shall provide to the State on a monthly basis, an accounting of collections resulting from audit work and enforcement actions resulting from a delegation of authority. Such accounting will identify collections broken down by royalties, penalties and interest paid.

[49 FR 40026, Oct. 12, 1984]

§ 229.108 Deduction of civil penalties accruing to the State or tribe under the delegation of authority.

Fifty percent of any civil penalty resulting from activities under a delegation of authority shall be shared with the delegated State. However, the amount of the civil penalty shared will be deducted from any Federal funding owed under a delegation of authority under the provisions of 30 U.S.C. 1735. MMS shall maintain records of civil penalties collected and distributed to

the States involved in 30 U.S.C. 1735 delegations. Each quarterly payment will be reduced by the amount of the civil penalties paid to the delegated State or tribe during the prior quarter.

[49 FR 37351, Sept. 21, 1984. Redesignated at 49 FR 40025, Oct. 12, 1984]

§ 229.109 Reimbursement for costs incurred by a State under the delegation of authority.

(a) The Department of the Interior (DOI) shall reimburse the State for 100 percent of the direct cost associated with the activities undertaken under the delegation of authority. The State shall maintain books and records in accordance with the standards established by the DOI and will provide the DOI, on a quarterly basis, a summary of costs incurred for which the State is seeking reimbursement. Only costs as defined under the provisions of 30 U.S.C. 1735 are eligible for reimbursement.

(b) The State shall submit a voucher for reimbursement of costs incurred within 30 days of the end of each calendar quarter.

[49 FR 37351, Sept. 21, 1984]

§ 229.110 Examination of the State activities under delegation.

(a) The Department will carry out an annual examination of the State's delegated activities undertaken under the delegation of authority.

(b) The examination required by this section will consist of a management review and a fiscal examination and evaluation to determine—

(1) That activities being carried out by the State under the delegation of authority meet the standards established by the Department and in particular the provisions of 30 U.S.C. 1735; and

(2) That costs incurred by the State under the delegation of authority are eligible for reimbursement by the Department.

[49 FR 37351, Sept. 21, 1984. Redesignated at 49 FR 40025, Oct. 12, 1984]

§ 229.111 Materials furnished to States necessary to perform delegation.

The MMS shall provide to the State all reports, files, and supporting materials within its possession necessary to allow the State to effectively carry out the terms of the delegation specified in § 229.104.

[49 FR 40026, Oct. 12, 1984]

DELEGATION REQUIREMENTS

SOURCE: Sections 229.120 through 229.126 appear at 49 FR 40026, Oct. 12, 1984, unless otherwise noted.

§ 229.120 Obtaining regulatory and policy guidance.

All activities performed by a State under a delegation must be in full accord with all Federal laws, rules and regulations, and Secretarial and agency determinations and orders relating to the calculation, reporting, and payment of oil and gas royalties. In those cases when guidance or interpretations are necessary, the State will direct written requests for such guidance or interpretation to the appropriate MMS officials. All policy and procedural guidance or interpretation provided by the MMS shall be in writing and shall be binding on the State.

§ 229.121 Recordkeeping requirements.

(a) The State shall maintain in a safe and secure manner all records, workpapers, reports, and correspondence gained or developed as a consequence of audit or investigative activities conducted under the delegation. All such records shall be made available for review and inspection upon request by representatives of the Secretary and the Department's Office of Inspector General (OIG).

(b) The State must maintain in a confidential manner all data obtained from DOI sources or from payor or company sources under the delegation which have been deemed ''confidential or proprietary'' by DOI or a company or payor. In this regard, the State regulatory authority shall be bound by provisions of 30 U.S.C. 1733. MMS shall provide to the State guidelines for determining confidential and proprietary material.

(c) All records subject to the requirements of paragraph (a) must be maintained for a 6-year period measured from the end of the calendar year in which the records were created. All dispositions or records must be with the

written approval of the MMS. Upon termination of a delegation, the State shall, within 90 days from the date of termination, assemble all records specified in subsection (a), complete all working paper files in accordance with § 229.124, and transfer such records to the MMS.

(d) The State shall maintain complete cost records for the delegation in accordance with generally accepted accounting principles. Such records shall be in sufficient detail to demonstrate the total actual costs associated with the project and to permit a determination by MMS whether delegation funds were used for their intended purpose. All such records shall be made available for review and inspection upon request by representatives of the Secretary and the Department's Office of Inspector General (OGIG).

§ 229.122 Coordination of audit activities.

(a) Each State with a delegation of authority shall submit annually to the MMS an audit workplan specifically identifying leases, resources, companies, and payors scheduled for audit. This workplan must be submitted 120 days prior to the beginning of each fiscal year. A State may request changes to its workplan (including the companies and leases to be audited) at the end of each quarter of each fiscal year. All requested changes are subject to approval by the MMS and must be submitted in writing.

(b) When a State plans to audit leases of a lessee or royalty payor for which there is an MMS or OIG resident audit team, all audit activities must be coordinated through the MMS or OIG resident supervisor. Such activities include, but are not limited to, issuance of engagement letters, arranging for entrance conferences, submission of data requests, scheduling of audit activities including site visits, submission of issue letters, and closeout conferences.

(c) The State shall consult with the MMS and/or OIG regarding resolution of any coordination problems encountered during the conduct of delegation activities.

§ 229.123 Standards for audit activities.

(a) All audit activities performed under a delegation of authority must be in accordance with the ''Standards for Audit of Governmental Organizations, Programs, Activities, and Functions'' as issued by the Comptroller General of the United States.

(b) The following audit standards also shall apply to all audit work performed under a delegation of authority.

(1) *General standards*—(i) *Qualifications.* The auditors assigned to perform the audit must collectively possess adequate professional proficiency for the tasks required, including a knowledge of accounting, auditing, agency regulations, and industry operations.

(ii) *Independence.* In all matters relating to the audit work, the audit organization and the individual auditors must be free from personal or external impairments to independence and shall maintain an independent attitude and appearance.

(iii) *Due professional care.* Due professional care is to be used in conducting the audit and in preparing related reports.

(iv) *Quality control.* The State governments must institute quality control review procedures to ensure that all audits are performed in conformity with the standards established herein.

(2) *Examination and evaluation standards—Standards and requirements for examination and evaluation.* Auditors should be alert to situations or transactions that could be indicative of fraud, abuse, or illegal acts with respect to the program. If such evidence exists, auditors should forward this evidence to MMS. The MMS will contact the appropriate Federal law enforcement agencies. The scope of examinations are to be governed by the principle of a justifiable relationship between cost and benefit as determined by the auditor or audit supervisor. Audit procedures should reflect the most efficient method of obtaining the requisite degree of satisfaction. The auditor should determine, to the extent possible, the effect on royalty reporting of the non-arms'-length nature of related party transactions, such as transfers of oil to refinery units affiliated with the producer. A review

should be made of compliance with the appropriate laws and regulations applicable to program operations. MMS shall issue guidelines as to the definition and nature of arms'-length and non-arms'-length transactions for use in carrying out delegated audit activities.

(3) *Standards of reporting.* (i) Written audit reports are to be submitted to the appropriate MMS officials at the end of each field examination.

(ii) A statement in the auditors' report that the examination was made in accordance with the generally accepted program audit standards (including the applicable General Accounting Office (GAO) standards) for royalty compliance audits should be in the appropriate language to indicate that the audit was made in accordance with this statement of standards.

(iii) The auditor's report should contain a statement of positive assurance on those items tested and negative assurance on those items not tested. It should also include all instances of noncompliance and instances or indications of fraud, abuse, or illegal acts found during or in connection with the audit.

(iv) The auditor's report should contain any other material deficiency identified during the audit not covered in paragraph (b)(3)(iii) of this section.

(v) When factors external to the program and to the auditor restrict the audit or interfere with the auditor's ability to form objective opinions and conclusions (such as denial of access to information by a company), the auditor is to notify the MMS. If the limitation is not removed, a description of the matter must be included in the auditor's report. MMS will take all legally enforceable steps necessary to seek information necessary to complete the audit.

(vi) If certain information is prohibited from general disclosure, the auditor's report should state the nature of the information omitted and the requirement that makes the omission necessary.

(vii) Written audit reports are to be prepared in the format prescribed by the MMS.

(viii) In instances where the extent of the audit findings or the amounts involved do not warrant it, a formal audit report need not be issued. In lieu of an audit report, a memorandum of audit findings will be prepared and placed on the case file.

[49 FR 40026, Oct. 12, 1984, as amended at 58 FR 64903, Dec. 10, 1993]

§ 229.124 Documentation standards.

Every audit performed by a State under a delegation of authority must meet certain documentation standards. In particular, detailed workpapers must be developed and maintained.

(a) *Workpapers* are defined to include all records obtained or created in performing an audit.

(b) Each audit performed varies in scope and detail. As a result, the audit team must determine the best presentation of the workpapers for a particular audit. The following general standards of workpaper preparation are consistent with the goal of achieving proper documentation while maintaining sufficient flexibility.

(1) All relevant information obtained orally must be promptly recorded in writing and incorporated in the workpapers.

(2) Workpapers must be complete and accurate in order to provide support for findings and conclusions.

(3) Workpapers should be clear and understandable without the need for supplementary oral explanations. The information they contain must be clear, complete, and concise, so that anyone using the workpapers will be able to readily determine their purpose, the nature and scope of the work done, and the conclusions drawn.

(4) Workpapers must be legible and as neat as practicable. They must meet standards which allow their use as evidence in judicial and administrative proceedings.

(5) The information contained in workpapers should be restricted to matters which are materially important and relevant to the objectives established for the assignment.

(6) Workpapers must be in sufficient detail to permit a subsequent independent execution of each audit procedure, assuming the target company retains its accounting documentation.

§ 229.125 Preparation and issuance of enforcement documents.

(a) Determinations of additional royalties due resulting from audit activities conducted under a delegation of authority must be formally communicated by the State, to the companies or other payors by an issue letter prior to any enforcement action. The issue letter will serve to ensure that all audit findings are accurate and complete by obtaining advance comments from officials of the companies or payors audited. Issue letters must be prepared in a format specified by the MMS, and transmitted to the company or payor. The company or payor shall be given 30 days from receipt of the letter to respond to the State on the findings contained in the letter.

(b) After evaluating the company or payor's response to the issue letter, the State shall draft a demand letter which will be submitted with supporting workpaper files to the MMS for appropriate enforcement action. Any sustantive revisions to the demand letter will be discussed with the State prior to issuance of the letter. Copies of all enforcement action documents shall be provided to the State by MMS upon their issuance to the company or payor.

§ 229.126 Appeals.

(a) Appeals made pursuant to the rules and procedures at 30 CFR parts 243 and 290 related to demand letters issued by officers of the MMS for additional royalties identified under a delegation of authority shall be filed with the MMS for processing. The State regulatory authority shall, upon the request of the MMS, provide competent and knowledgeable staff for testimony, as well as any required documentation and analyses, in support of the lessor's position during the appeal process.

(b) An affected State, upon the request of the MMS, shall provide expert witnesses from their audit staff for testimony as well as required documentation and analyses to support the Department's position during the litigation of court cases arising from denied appeals. The cost of providing expert witnesses including travel and per diem is reimbursable under the provisions of a delegation of authority, at the Federal Government's existing per diem rates.

§ 229.127 Reports from States.

The State, acting under the authority of the Secretarial delegation, shall submit quarterly reports which will summarize activities carried out by the State during the preceding quarter of the year under the provisions of the delegation. The report shall include:

(a) A statistical summary of the activities carried out, e.g., number of audits performed, accounts reconciled, and other actions taken;

(b) A summary of costs incurred during the previous quarter for which the State is seeking reimbursement; and

(c) A schedule of changes which the State proposes to make from its approved plan.

[49 FR 37351, Sept. 21, 1984. Redesignated at 49 FR 40025, Oct. 12, 1984]

PART 230—RECOUPMENTS AND REFUNDS

Subpart A—General Provisions

Sec.

230.51 Cross-lease netting in calculation of overpayments under section 10 of the OCSLA.

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Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

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450.458 Unauthorized credit adjustments.
230.549 Stopping or tolling of the section 10(a) 2-year period.
230.460 Lease suspension.
230.461 Transactions not subject to section 10.

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

SOURCE: 57 FR 62207, Dec. 30, 1992, unless otherwise noted.

Subpart A—General Provisions

§ 230.51 Cross-lease netting in calculation of overpayments under section 10 of the OCSLA.

(a) The amount of any refund or credit for any overpayment for any lease or leases governed by the Outer Continental Shelf Lands Act (OCSLA), as amended, for any production month shall not be reduced by offsetting against that overpayment any reported underpayment by the payor on any other lease or leases, except as provided in paragraph (b) of this section.

(b) Royalties attributed to production from a lease or leases governed by the OCSLA, which should have been attributed to production from a different lease or leases governed by the OCSLA, may be offset without regard to the provisions of OCSLA section 10, 43 U.S.C. 1339, only if the payor submits a written request to Minerals Management Service (MMS), Fiscal Accounting Division, for its approval of the correction and provides adequate documentation to show that the following conditions exist and are met:

(1) The error results from attributing and reporting an equal volume of production, produced from a lease or leases during a particular production month, to a different lease or leases from which that production was not produced for the same or another production month;

(2) The payor is the same for the lease or leases to which the production was attributed and the lease or leases to which it should have been attributed;

(3) The payor submits production reports, pipeline allocation reports, or other similar documentary evidence pertaining to the specific production involved which verifies the correct production information; and

(4) In the case of leases which are within the zone defined and governed by section 8(g) of the OCSLA, as amended, 43 U.S.C. 1337(g), the leases are located off the coast of the same State.

(c) If MMS approves a correction pursuant to paragraph (b) of this section, the payor is required to submit an adjusting royalty report (Form MMS–2014) pursuant to 30 CFR part 210 to correct its reporting to the Auditing and Financial System.

(d) If MMS requires a repayment of principal royalties or assesses late-payment interest as a result of the payor having improperly offset any underpayment against an overpayment and,

therefore, having failed to request a refund or credit as required by section 10 of the OCSLA, 43 U.S.C. 1339, and the payor asserts pursuant to 30 CFR part 290 that some or all of the royalties or interest assessed is not owed pursuant to the exception set forth in paragraph (b) of this section, the burden is on the payor to demonstrate that the exception applies in the specific circumstances of the case.

(e) The exception set forth in paragraph (b) of this section shall not operate to relieve any payor of any liability imposed by statute or regulation for erroneous reporting.

Subpart B—Oil, Gas, and OCS Sulfur, General [Reserved]

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

Subpart J—Refunds and Recoupments of Overpayments Under Federal Leases on the Outer Continental Shelf; Implementation of Section 10 of the Outer Continental Shelf Lands Act

SOURCE: 59 FR 38363, July 28, 1994, unless otherwise noted.

§ 230.451 Scope.

This subpart establishes the procedures that lessees and other persons who make royalty and other payments on Federal oil and gas leases on the Outer Continental Shelf (OCS) must follow to recover certain excess payments made in connection with their leases in accordance with section 10 of the Outer Continental Shelf Lands Act (section 10), 43 U.S.C. 1339. The requirements of this subpart apply to both requests for refund from the Treasury of excess payments and requests to recover excess payments by recouping the amount through a credit adjustment. This subpart applies only to Federal leases on the OCS.

§ 230.452 Definitions.

Terms used in this subpart shall have the same meaning as in 30 U.S.C. 1702. In addition, the following definitions apply to this subpart:

Credit or *crediting* means reduction of a current or future royalty or other payment made in connection with a lease as a result of reporting a credit adjustment.

Credit Adjustment means any adjustment reported on a Report of Sales and Royalty Remittance (Form MMS–2014) or any other royalty report form which reduces any royalty or other payment made in connection with a lease which was reported and paid in any previous period.

Offset means to net or cancel previous overpayments against previous underpayments on the same OCS lease or across lease boundaries if all the individual leases are part of an approved unit agreement.

Overpayment means any payment made in excess of the amount that the lessee was lawfully required to pay.

Payment means money MMS receives in satisfaction of a lessee's royalty, rental, bonus, net profit share, or late payment interest obligation as established by statute, regulation, or the terms of a lease.

Recoup or *recoupment* means to recover a previous overpayment through a credit against a current or future royalty or other payment or liability under an OCS lease. A recoupment occurs whenever a payor reports a credit adjustment on a Form MMS–2014 or other royalty report form resulting in a net negative dollar value for the transaction and the credit is taken against the royalty or other payment

or liability shown in the balance of the report.

Refund means a repayment by the United States Treasury to a person of any overpayment.

Unit means an area of 2 or more leases subject to an agreement for the consolidated development and recovery of oil and gas contained on the leases which are part of the agreement approved by MMS.

§ 230.453 Request for refund or credit.

(a) Except as otherwise provided in this subpart, no person may recover an excess payment it has made in connection with an OCS lease unless:

(1) That person has made a request for refund or credit in accordance with the provisions of this subpart;

(2) MMS has transmitted a report on the request for refund or credit to the President of the Senate and the Speaker of the House of Representatives and 30 days have expired since the submission in accordance with section 10(b), 43 U.S.C. 1339(b); and

(3) MMS notifies the person that its request for refund or credit is authorized and that the person may receive its refund for, or may report a credit adjustment to recoup, the excess payment.

(b) A request for refund or credit must:

(1) Be in writing;

(2) Provide the person's MMS-established payor code;

(3) Identify the leases and sales months with respect to which the excess payments occurred;

(4) Identify the amount of the excess payment or, with specificity, describe a class of payments that are, or as a result of an administrative or judicial decision or other identified contingency, may become, excess payments;

(5) Provide the reasons why a refund or credit is due;

(6) Include a certification that, to the best of the person's knowledge or belief, the information provided in response to paragraphs (b)(2) through (b)(5) of this section is accurate and complete.

(c) If MMS determines that a request for refund or credit is incomplete, the person who submitted the request will have 30 days, or such time as MMS may specify, following notice from MMS, to supplement the request for refund or credit.

(d) A credit adjustment reported on a Form MMS–2014 does not constitute a request for refund or credit for purposes of this section, and does not constitute an incomplete request for refund or credit for purposes of paragraph (c) of this section.

(e) A person who has filed a request for refund or credit pursuant to this section may amend that request to add an additional amount if:

(1) The additional amount is for the same lease and sales month; and

(2) The reason for the excess payment for the additional amount is the same as for the originally requested amount.

(f) Except as otherwise provided in this subpart, no request for a refund or credit will be approved unless the request is received at MMS at the address provided below within 2 years of the date that MMS received the excess payment.

(1) The request for refund or credit must be received at the following address:

(i) By mail: Minerals Management Service, Section 10 Refund Requests, P.O. Box 173702, Denver, CO 80217–3702.

(ii) By express delivery or courier: Minerals Management Service, Section 10 Refund Requests, Building 85, Denver Federal Center, Room A–212, Denver, CO 80225.

(2) If the last day of the 2-year period from the date MMS received the excess payment falls on a Saturday, Sunday, holiday or any other day that MMS is not open for business at the address specified in paragraph (f)(1) of this section, then the last day of the 2-year period will be the next regular business day. Requests received at the specified MMS address after 4 p.m. Mountain Time are considered received the following business day.

§ 230.454 Interest on excess payments.

No person is entitled to interest on any excess payment made in connection with a lease that is refunded or recouped pursuant to this subpart.

§ 230.455 Authorization of refund or credit and subsequent audit.

MMS may grant a refund or authorize a credit based upon satisfactory evidence that the payment for which a refund or credit is requested was made, and upon a determination that the payment was excess. An approved request for refund or credit may be subject to later review or audit by MMS. If, based upon later review or audit, MMS determines that the refund or credit should not have been granted or authorized, the person who requested the refund or credit must repay the amount refunded or recouped plus interest determined pursuant to 30 U.S.C. 1721(a) and 30 CFR 218.150 from the date the refund was made or the recoupment taken until the date it is repaid.

§ 230.456 Offsets of overpayments and underpayments on the same lease (or unit) by the same person.

If a person makes an overpayment on any OCS lease or unit in a prior month, it may offset that overpayment against an underpayment that same person made in any prior month on that same lease or unit for the same or a different product without submitting a request for refund or credit. This offset is permitted only if the underpayment was not created as a result of a credit adjustment to recoup the amount of the overpayment or was not otherwise created intentionally to provide an underpayment against which to offset the overpayment. This offset also is subject to any limitations imposed by other applicable law or regulations.

§ 230.457 Offsets among different persons who reported and paid royalties on a lease for the same prior sales month.

(a) This section applies to any reallocation of production for a prior sales month among different persons who reported and paid royalty for that month on a lease or unit, except for reallocations of production that result from the approval or amendment of a unit agreement subject to § 230.461(b).

(b) In the event of a reallocation of production as described in paragraph (a) of this section, the respective persons who reported and paid royalty may reconcile any resulting differences in royalty payment obligations between themselves without submitting revised royalty reports or requests for refund or credit to MMS under this subpart, except that:

(1) Any person who paid any amount which remains as a net overpayment after such reconciliation must file a request for refund or credit in accordance with the requirements of this subpart to recover the excess payment;

(2) Any person whose royalty obligation remains underpaid after such reconciliation must report the additional royalties due for the prior sales month on a Form MMS–2014 and pay interest on the underpayment from the last day of the month following the sales month until the date the additional royalties are paid; and

(3) All persons involved in such reconciliation must retain all documents pertaining to the reallocation of production, calculation of royalties due, and the subsequent reconciliation among the persons involved together with other records pertaining to production from that lease during the prior sales month and the royalty due and paid thereon, and make such documents available for review and audit in the same manner as other records pertaining to the lease.

(c) If persons who reported and paid royalty do not reconcile between themselves any differences in royalty payment obligations arising as a result of a reallocation as provided in paragraph (b) of this section, each person who pays royalties for the lease must report and pay any additional royalties due, or file a request for refund or credit in accordance with the requirements of this subpart to recover the excess payment, as applicable. Any person who reports additional royalties due for the prior sales month must pay interest pursuant to 30 CFR 218.54 on the underpayment from the last day of the month following the sales month until the date the additional royalties are paid.

§ 230.458 Unauthorized credit adjustments.

(a) If a person reports a credit adjustment on Form MMS–2014 that results in a credit before MMS approves the recoupment pursuant to § 230.455, and if

the credit adjustment does not qualify as one of the transactions not subject to section 10 as provided in § 230.461, then that person has taken an unauthorized credit adjustment.

(1) If the unauthorized credit adjustment recouped a payment that MMS received more than 2 years before the date MMS received the Form MMS–2014 which includes the unauthorized credit adjustment, the person must repay the amount recouped plus late payment interest determined pursuant to 30 U.S.C. 1721(a) and 30 CFR 218.150 from the date the unauthorized recoupment was taken until the date it is repaid. Unless the person filed a request for refund or credit pursuant to § 230.453 within 2 years of the making of the excess payment for which the unauthorized credit adjustment was reported, the excess payment is not subject to refund or recoupment.

(2) If the unauthorized credit adjustment recouped a payment that MMS received less than 2 years before the date MMS received the Form MMS–2014 with the unauthorized credit adjustment, the person must repay the amount recouped plus late payment interest determined pursuant to 30 U.S.C. 1721(a) and 30 CFR 218.150 from the date the unauthorized recoupment was taken until the date it is repaid. The report of the unauthorized credit adjustment on the Form MMS–2014 does not constitute a request for refund or credit that tolls the 2-year period in section 10(a), 43 U.S.C. 1339(a). The person may file a request for refund or credit pursuant to section 230.453 for the payment for which the unauthorized credit adjustment was reported. MMS will review the request pursuant to the requirements of this subpart only if the request for refund or credit is received within 2 years of the making of the original payment for which the unauthorized credit adjustment was reported.

(b) A person who reports an unauthorized credit adjustment to MMS on a Form MMS–2014 will be assessed $500 for each unauthorized credit adjustment reported.

§ 230.459 Stopping or tolling of the section 10(a) 2-year period.

(a) The period of 2 years from the making of the excess payment, within which a request for refund or credit must be filed under section 10(a), 43 U.S.C. 1339(a), will be:

(1) Tolled by MMS's receipt of a substantially complete request for refund or credit pursuant to § 230.453; or

(2) Tolled by a general tolling notice issued by MMS and published in the FEDERAL REGISTER in circumstances where MMS believes a substantial number of requests for refund or credit could result as a consequence of a pending administrative or judicial proceeding or other action. The running of the 2-year period will be tolled for the time period specified in the notice; or

(3) Stopped by an application for unitization of OCS leases with respect to any excess payment that may result from the reallocation of production among leases after the unit or revision is approved; or

(4) Tolled by a notice filed by a person at the address stated in § 230.453(f) stating that a specifically identified action or proceeding may result in payments made on an OCS lease becoming excess payments. The notice must include:

(i) A list of affected leases and sales months;

(ii) The specific action or proceeding that could result in payments becoming excess;

(iii) An estimate of the amount that could be subject to a request for refund or credit; and

(iv) The person's MMS-established payor code.

(b) A request for refund or credit that is filed timely by a person who made an excess payment on an OCS lease does not stop or toll the running of the 2-year period with respect to any excess payment made by any other person on that lease.

§ 230.460 Lease suspension.

If MMS suspends an OCS lease pursuant to 30 CFR 250.10(b)(6), a person who has made excess rental payments for the period of suspension may request a

refund or credit of any excess payments pursuant to this subpart. If the request for refund or credit is filed more than 2 years after MMS received the excess rentals, the excess payment will not be refunded, recouped, or credited against future rentals due on the same lease.

§ 230.461 Transactions not subject to section 10.

(a) A request for refund of, or any other action to recover, excess payments made by a refiner/purchaser under a royalty-in-kind contract for royalty oil produced from an OCS lease is not subject to section 10.

(b) If MMS approves a unit agreement on the OCS, or a revision to a unit, a person may file amended Forms MMS–2014 within the time period MMS prescribes, reallocating production among its affected leases. A person must file a request for refund or credit pursuant to this subpart only if, and to the extent that, there is a net reduction in the royalty that person previously paid for the leases committed to the unit as a result of the amendments.

(c) A person may amend Form MMS–2014 to adjust volume and royalty reports among OCS leases within a unit within the same sales month without filing a request for refund or credit pursuant to this subpart, except that a request for refund or credit must be filed to the extent that there is a net reduction in the royalty previously paid for the leases committed to the unit as a result of the amendments.

(d) A person who pays more money than the total royalty due as reported on the Form MMS–2014 accompanying the payment, where all amounts reported on the Form MMS–2014 are correct, may submit a request for refund of the overpaid amounts. The request for refund is not subject to section 10's requirements unless the Form MMS–2014 includes reports for only one OCS lease. Any overpayment subject to this paragraph may not be recovered by recoupment.

(e) A person may reduce an estimate balance, established for any lease product pursuant to MMS instructions, by submitting a credit adjustment on a Form MMS–2014, or a request for refund, for all or part of the established estimate balance. A credit adjustment or request for refund to recover all or part of an estimate balance authorized by this paragraph is not subject to the requirements of section 10.

(f)(1) If adjustment of an estimated oil transportation allowance or estimated gas transportation allowance pursuant to 30 CFR 206.105(e) and 206.157(e), respectively, results in an overpayment for any sales month because the estimated transportation costs were less than the actual costs, a person may submit a credit adjustment on a Form MMS–2014 to recoup, or may request a refund of, the overpayment. The credit adjustment or request for refund authorized by this paragraph is not subject to the requirements of section 10, and MMS approval is not required before reporting the credit adjustment.

(2) If adjustment of an estimated gas processing allowance pursuant to 30 CFR 206.159(e) results in an overpayment for any sales month because the estimated processing costs were less than the actual costs, a person may submit a credit adjustment on a Form MMS–2014 to recoup, or may request a refund of, the overpayment. The credit adjustment or request for refund authorized by this paragraph is not subject to the requirements of section 10, and MMS approval is not required before reporting the credit adjustment.

(3) If a person makes an error in the report of actual transportation or processing costs pursuant to paragraphs (f)(1) or (f)(2) of this section, any subsequent adjustment to the report that results in a credit is subject to section 10 and the requirements of this subpart.

(g) If a person pays pursuant to an MMS order and challenges the obligation to pay in an administrative appeal or judicial action, and if the person is successful in a challenge to all or part of the MMS order to pay, section 10 does not apply to the refund or recoupment of the disputed payment or portion thereof.

(h) MMS approval is not required for an adjustment by any person to the amount reported for a report month that results in a credit of not more than an amount established periodically by MMS and published in the

FEDERAL REGISTER. However, no adjustment may be reported more than 2 years after the date MMS received the Form MMS–2014 including the excess payment.

PART 232—INTEREST PAYMENTS [RESERVED]

PART 233—ESCROW AND INVESTMENTS [RESERVED]

PART 234—BONDING—PAYMENT LIABILITY [RESERVED]

PART 241—PENALTIES

Subpart A—General Provisions

Sec.

241.20 Civil penalties authorized by statutes other than the Federal Oil and Gas Royalty Management Act of 1982.

Subpart B—Oil, Gas, and OCS Sulfur, General

241.50 Definitions.
241.51 Civil penalties authorized by the Federal Oil and Gas Royalty Management Act of 1982.
241.52 Criminal penalties.
241.53 Assessments for nonperformance.

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal [Reserved]

Subpart I—OCS Sulfur [Reserved]

AUTHORITY: 25 U.S.C. 396 *et seq.*; 25 U.S.C. 396a *et seq.*; 25 U.S.C. 2101 *et seq.*; 30 U.S.C. 181 *et seq.*; 30 U.S.C. 351 *et seq.*; 30 U.S.C. 1001 *et seq.*; 30 U.S.C. 1701 *et seq.*; 43 U.S.C. 1301 *et seq.*; 43 U.S.C. 1331 *et seq.*; and 43 U.S.C. 1801 *et seq.*

Subpart A—General Provisions

§ 241.20 Civil penalties authorized by statutes other than the Federal Oil and Gas Royalty Management Act of 1982.

(a) Whenever a lessee, operator, revenue payor, or other authorized person fails to comply with any regulations, orders or notices, the appropriate MMS official shall give the lessee, operator, revenue payor, or other authorized person notice in writing to remedy any violations.

(b) Failure by the lessee, operator, revenue payor, or other authorized person, or other party to complete the necessary remedial action within the time and in the manner prescribed by the notice may subject the lease to cancellation proceedings pursuant to 30 CFR 250.12 for offshore leases, 43 CFR subpart 3163 and 3108 for Federal onshore leases, or provisions of 25 CFR for Indian leases.

(c) The lessee, operator, revenue payor, or other authorized person, shall be subject to a penalty of not more than $500 per day for each day the violation specified in the notice continues beyond the date specified in the notice, not to exceed 60 days. In addition to this penalty or in lieu thereof, MMS can take steps to cancel the lease.

(d) No penalty under this section shall be assessed until the person charged with a violation has been given the opportunity for a hearing. Hearings shall be held by the appropriate MMS official whose findings shall be conclusive unless an appeal is taken pursuant to 30 CFR part 243.

[49 FR 37352, Sept. 21, 1984; 49 FR 40576, Oct. 17, 1984]

Subpart B—Oil, Gas, and OCS Sulfur, General

AUTHORITY: The Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701 *et seq.*).

§ 241.50 Definitions.

Terms used in subparts B, C, and D of this part shall have the same meaning as in 30 U.S.C. 1702.

[49 FR 37352, Sept. 21, 1984, as amended at 53 FR 1226, Jan. 15, 1988]

§ 241.51 Civil penalties authorized by the Federal Oil and Gas Royalty Management Act of 1982.

(a)(1) *Notice of noncompliance.* If the MMS believes that any person has failed or refused to comply with any statute, regulation, rule, order, lease, or permit governing the determination and collection of royalties on Federal or Indian lands or on the Outer Continental Shelf, the MMS may issue a notice of noncompliance which shall set forth the nature of the violation and the remedial action required.

(2) The notice of noncompliance shall be served by personal service by an authorized representative of the MMS or by registered mail. Service by registered mail shall be deemed to occur when received or 5 days after the date it is mailed, whichever is earlier.

(3) When a notice of noncompliance is issued by the MMS under this section:

(i) Unless the violation is corrected within 20 days (or such longer time as specified in the notice) from the date that the notice is served, the person upon whom the notice is served shall be liable for a penalty of up to $500 per violation for each day such violation continues, dating from the date of service of the notice;

(ii) Unless the violation is corrected within 40 days (or such longer time as specified in the notice) from the date that the notice is served, the person upon whom the notice is served shall be liable for a penalty of up to $5,000 per violation for each day such violation continues;

(iii) If the person upon whom the notice is served does not correct the violation within 20 days (or such longer time as specified in the notice) from the date that the notice is served, such person may, by that date, request a hearing on the record by filing a written request with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 4015 Wilson Boulevard, Arlington, Virginia 22203.

(4) If the person upon whom a notice of noncompliance has been served pursuant to paragraph (a)(3) of this section corrects the violations within 20 days (or such longer time as specified in the notice) from the date that the notice is served, no penalties shall be assessed by the MMS under this section and the person shall not be entitled to a hearing on the record provided for in paragraph (a)(3)(iii) of this section. The person may appeal the notice of noncompliance or other disputed MMS decision or order in accordance with the appeals procedures in 30 CFR part 243.

(b)(1) *Notice of noncompliance for intentional violations.* In addition to the provisions of paragraph (a) of this section, the MMS may issue a notice of noncompliance for intentional violations, which shall set forth the nature of the violation and the remedial action required, to any person who—

(i) Knowingly or willfully fails to make any payment due by the date as specified by statute, regulation, order, or terms of the lease;

(ii) Knowingly or willfully fails to submit or submits false, inaccurate, or misleading data to the MMS in support of a royalty, rental, bonus, or other payment; or

(iii) Knowingly or willfully prepares, maintains, or submits false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information.

(2) A person served with a notice of noncompliance for an intentional violation under this paragraph shall be liable for a penalty of up to $10,000 per violation for each day such violation continues.

(3) The notice of noncompliance for intentional violation shall be served in accordance with paragraph (a)(2) of this section.

(4) A person who has been served with a notice of noncompliance for intentional violation issued pursuant to this subsection shall have 20 days from the date of service to file a written request for a hearing on the record with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 4015 Wilson Boulevard, Arlington, Virginia 22203.

(c) *Penalty notice.* The MMS shall issue a penalty notice to any person subject to penalties under this section. The penalty notice shall set forth the amount of the penalty applicable for each day that the violation continues. The penalty amount shall be determined by MMS taking into account the

severity of the violation and the person's history of noncompliance. The penalty for each day that a violation continues shall not exceed the amounts specified in paragraphs (a) and (b), of this section as applicable.

(d) Penalties imposed under this section shall be in addition to interest assessed on payments not received by the MMS by the due date and assessments for later or incorrect reporting pursuant to part 218 of this chapter.

(e) If the person served with a notice of noncompliance requests a hearing on the record pursuant to paragraph (a)(3)(iii) or paragraph (b)(4) of this section, penalties shall accrue each day until the person corrects the violations set forth in the notice of noncompliance. The Director, MMS, may suspend the requirement to correct the violations pending completion of the hearings provided by this section, but only if the Director, MMS, suspends the obligation in writing, and then only upon a determination, at the discretion of the Director, that such suspension will not be detrimental to the lessor and upon submission and acceptance of a bond deemed adequate to indemnify the lessor from loss or damage. The amount of the bond must be sufficient to cover any disputed amounts plus accrued penalties and interest. The MMS may require, at any time, adjustment in the amount of the bond for increases in the amount of the underlying obligations determined by MMS to be due, for penalties or for interest.

(f) *Hearing.* If a person served with a notice of noncompliance has requested a hearing on the record in accordance with paragraph (a)(3)(iii) or (b)(4) of this section, the hearing shall be conducted by an Administrative Law Judge (Departmental), Office of Hearings and Appeals. After the hearing, the Administrative Law Judge shall issue a decision in accordance with the evidence presented and applicable law. Any party to a case adversely affected by a decision of the Administrative Law Judge may appeal that decision to the Interior Board of Land Appeals in accordance with the procedures set forth in 43 CFR part 4. A decision by the Interior Board of Land Appeals shall be a final order which may be appealed in accordance with paragraph (i) of this section.

(g) The Director of the MMS shall issue an order assessing the penalty, in accordance with the penalty notice, against any person subject to penalties under paragraph (a) or (b) of this section who does not request a hearing on the record as provided in paragraph (a)(3)(iii) or (b)(4) of this section. The penalty assessment must be paid within 30 days of its issuance and shall be a final order subject to collection pursuant to the provisions of paragraph (j) of this section.

(h) On a case-by-case basis the Secretary, or his/her authorized representative, may compromise or reduce civil penalties under this section. The amount of any penalty under this section, as finally determined, may be deducted from any sums owing by the United States to the person charged.

(i) Any person who has requested a hearing in accordance with paragraph (a) or (b) of this section within the time prescribed for such a hearing and who is aggrieved by a final order may seek review of such order in the U.S. District Court for the judicial district in which the violation allegedly took place. Review by the District Court shall be only on the administrative record and not *de novo.* Such action shall be barred unless filed within 90 days after the final order.

(j) If any person fails to pay an assessment of a civil penalty under this section after the order making the assessment has become a final order, and if such person has not filed a petition for judicial review in accordance with paragraph (i) of this section, or, after a court, in an action brought under this section, has entered a final judgment in favor of the Secretary, the Court shall have jurisdiction to award the amount assessed plus interest assessed from the date of the expiration of the 90-day period referred to in paragraph (i) of this section. The amount of any penalty, as finally determined, may be deducted from any sum owing by the United States to the person charged.

[49 FR 37352, Sept. 21, 1984]

§ 241.52 Criminal penalties.

Any person who commits an act for which a civil penalty is provided at 30

U.S.C. 1719 shall be subject to criminal penalties as provided at 30 U.S.C. 1720.

[49 FR 37352, Sept. 21, 1984]

§241.53 Assessments for nonperformance.

Administrative costs arising out of certain defaults or violations of orders requiring the performance of certain duties by lessees, as set forth in the regulations in this part, constitute loss or damage to the United States the amount of which is difficult or impracticable of ascertainment. Therefore, the following amounts shall be deemed to cover such loss or damage and shall be payable upon receipt of notice from the Associate Director of such loss or damage.

(a) For failure to comply with a written order or instructions of the Associate Director, $250 if compliance is not obtained within the time specified.

(b) For failure to file sales contracts or division orders as required by lease terms, $25 for each violation, and for failure to submit pipeline run tickets, or other proper evidence of disposal as required by these regulations, $10 for each violation.

[47 FR 47775, Oct. 27, 1982. Redesignated at 48 FR 35641, Aug. 5, 1983, further redesignated and amended at 53 FR 1226, Jan. 15, 1988]

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F—Coal [Reserved]

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PART 242—NOTICES AND ORDERS [RESERVED]

PART 243—APPEALS—ROYALTY MANAGEMENT PROGRAM

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243.1 Procedure.
243.2 Suspension of orders or decisions pending appeal.
243.3 Exhaustion of administrative remedies.
243.4 Service of official correspondence.

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

Subpart A—General Provisions

§243.1 Procedure.

Except as may otherwise be provided in part 241 hereof, an order or decision issued under regulations administered by the Royalty Management Program may be appealed in accordance with the provisions of part 290 of this chapter.

[49 FR 37353, Sept. 21, 1984]

§ 243.2 Suspension of orders or decisions pending appeal.

(a) Compliance with any orders or decisions issued by the Royalty Management Program (RMP) of the Minerals Management Service (MMS), including orders for payments of royalty deficiencies (other than orders to pay additional royalties for the difference between a cents-per-ton royalty clause and an ad volorem royalty clause pursuant to the terms of coal leases following readjustment by the Bureau of Land Management (BLM)), rentals, interest, penalties (other than civil penalties provided for under section 109 of the Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. 1719, and implemented in 30 CFR 241.51), royalty-in-kind contract payments, or other assessments, shall be suspended by reason of an appeal having been taken pursuant to 30 CFR part 290 unless the Director, MMS, notifies the appellant in writing that the decision or order shall not be suspended pending appeal. Unless the amount under appeal is $1,000 or less, suspension of an order or decision requiring the payment of a specified amount of money shall be contingent upon the appellant's submission within a time period prescribed by MMS of an MMS-specified surety instrument deemed adequate to indemnify the lessor from loss or damage. Nothing in this paragraph shall be construed to prohibit an appellant from paying any demanded amount pending appeal. If the appeal is granted in whole or in part, the appellant will be entitled to a refund of the amount paid, without interest, in accordance with MMS refund procedures.

(b)(1) For purposes of this section, an ''MMS-specified surety instrument'' for fluids (oil, gas, and geothermal) leases means either: An MMS-specified administrative appeal bond; an MMS-specified irrevocable letter of credit; Treasury book-entry bond or note; or financial institution book-entry certificate of deposit. The ''MMS-specified surety instrument'' shall be in a form specified by MMS instructions or approved by MMS. A bond must be issued by a qualified surety company which has been approved by the Department of the Treasury. An irrevocable letter of credit or a certificate of deposit must be from a financial institution acceptable to MMS with a minimum 1-year period of coverage subject to automatic renewal up to 5 years. The MMS will use a bankrating service to determine whether a financial institution has an acceptable rating to provide a surety instrument deemed adequate to indemnify the lessor from loss or damage. The MMS will accept only an ''MMS-specified surety instrument'' as qualified in this paragraph and in paragraph (c) of this section. The MMS will accept a single surety instrument that covers multiple amounts under appeal. The single surety instrument must be amended annually to either add new amounts or remove amounts that have been adjudicated. New amounts under appeal each year require a separate surety instrument until covered by the single surety instrument during the annual amendment.

(2) For purposes of this section, an ''MMS-specified surety instrument'' for other than fluids (oil, gas, and geothermal) leases, is the BLM lease surety instrument which must be increased at the request of MMS to cover royalty and interest obligations. However, if BLM has no lease surety instrument coverage, or the appellant chooses to provide a separate surety instrument to MMS, or the appellant is not the lessee of record, then an ''MMS-specified surety instrument'' in accordance with paragraph (b)(1) of this section is required.

(3) The ''MMS-specified surety instrument'' for RMP is subject to approval by a bond-approving officer. The designated bond-approving officer for RMP is the Associate Director for Royalty Management or delegated officials. The MMS will provide in writing to the appellant information and standard forms on ''MMS-specified surety instrument'' requirements.

(c)(1) The amount of the bond, letter of credit, Treasury book-entry bond or note, or financial institution book-entry certificate of deposit will be determined by MMS and will include the principal amount owed plus any accrued interest owed and projected interest for a 1-year period. In the case of Treasury book-entry bonds or notes, the amount must be equal to 120 percent of the required surety amount.

(2) If a decision on the appeal is not made within 1 year from the date the appeal is filed, appellants who submitted a bond shall amend the bond amount to cover additional estimated interest for another 1-year period. Appellants who submitted a letter of credit, a Treasury book-entry bond or note, or a financial institution book-entry certificate of deposit shall submit, at least 10 calendar days prior to the expiration date, a new surety instrument or an amendment to the existing surety instrument for an additional 1-year period of time with an increase in the amount to cover estimated interest for a 1-year period. In all cases, MMS will determine the additional estimated interest and amended surety instrument amount. If a surety instrument is not amended to include the additional interest coverage at least 10 calendar days prior to the expiration date of the surety instrument, MMS may make a demand against and collect from the surety. The collection against the surety will include the principal amount owed plus accrued interest.

(d)(1) An MMS decision or order that is appealed to the Interior Board of Land Appeals pursuant to 30 CFR part 290 and 43 CFR part 4, shall be suspended pending appeal if the appellant submits or maintains a surety instrument in accordance with the provisions of this section, unless the Director or the Deputy Commissioner of Indian Affairs (when Indian lands are involved) notifies the appellant in writing at the time the decision or order is issued that it will not be suspended pending appeal. The Director or the Deputy Commissioner of Indian Affairs may deny suspension of an appeal to avoid irreparable harm to the lessor.

(2) In any case where the Director of the Office of Hearings and Appeals or the Secretary takes jurisdiction of an administrative appeal involving a Royalty Management Program decision or order pursuant to 43 CFR part 4.5 and grants a suspension of effectiveness of the decision or order subject to the submission of an adequate surety instrument, the appellant must maintain that surety instrument in accordance with the requirements of this section.

(e) An Interior Board of Land Appeals decision, other final action of the Department of the Interior regarding a Royalty Management Program decision or order, or a Royalty Management Program decision or order which is made effective pending appeal under paragraph (a), which is the subject of an action for judicial review in a United States District Court of competent jurisdiction will be suspended pending judicial review pursuant to 5 U.S.C. 705 if the plaintiff seeking review submits or maintains a surety instrument in accordance with the provisions of this section, unless the Government notifies the court that it will not agree to a suspension of the effectiveness of the decision or order pending judicial review.

(f) The MMS may initiate collection against a surety instrument if:

(1) The MMS Director decides an administrative appeal adversely to the appellant, and the appellant fails either to pay the disputed amount or pursue a further administrative appeal and maintain an adequate surety instrument pending such appeal;

(2) The Interior Board of Land Appeals, the Director of the Office of Hearings and Appeals, an Assistant Secretary, or the Secretary decides an administrative appeal adversely to the appellant, and the appellant fails either to pay the disputed amount or pursue judicial review and maintain an adequate surety instrument pending such judicial review, in accordance with paragraph (e);

(3) A court of competent jurisdiction issues a final nonappealable decision adverse to the appellant/plaintiff and the appellant/plaintiff fails to pay the disputed amount; or

(4) The appellant fails to increase the amount of the surety instrument as required under paragraph (c) or otherwise fails to maintain an adequate surety instrument in effect.

[57 FR 44997, Sept. 30, 1992]

§243.3 Exhaustion of administrative remedies.

In order to exhaust administrative remedies, a decision or order of MMS' Royalty Management Program must be appealed pursuant to 30 CFR part 290 to the Director (or the Deputy Commissioner of Indian Affairs when Indian lands are involved), and subsequently

to the Interior Board of Land Appeals under 30 CFR part 290.7 and 43 CFR part 4 unless the order has been made effective by the Director, or by the Assistant Secretary for Land and Minerals Management, or by the Assistant Secretary for Indian Affairs, or by the Interior Board of Land Appeals pursuant to 43 CFR part 4, as applicable.

[57 FR 44998, Sept. 30, 1992]

§ 243.4 Service of official correspondence.

(a) *Method of service.* Official correspondence issued by the Royalty Management Program (RMP) will be served by sending the document certified or registered mail, return receipt requested, to the addressee of record established in paragraph (b) of this section. Instead of certified or registered mail, RMP may deliver the document personally to the addressee of record and obtain a signature acknowledging the addressee's receipt of the document. Official correspondence includes all RMP orders that are appealable in accordance with the provisions of this part and 30 CFR part 290.

(b) *Addressee of record.* (1) The addressee of record for administrative correspondence for refiners participating in the government's Royalty-in-Kind (RIK) Program is the position title, department name and address, or individual name and address identified in the executed royalty oil sale contract. A different position title, department name and address, or individual name and address may be identified, in writing, by the refiner/purchaser for billing purposes. The refiner must notify the Minerals Management Service (MMS), in writing, of all addressee changes.

(2) The addressee of record for serving official correspondence on anyone required to report energy and mineral resources removed from Federal and Indian leases to the RMP Production Accounting and Auditing System is the most recent position title, department name and address, or individual name and address that RMP has in its records for the reporter/payor. The reporter/payor is responsible for notifying RMP, in writing, of any addressee changes.

(3) The addressee of record for serving official correspondence concerning onshore Federal leases is the current lessee of record with the Bureau of Land Management. For Indian leases, the addressee of record is the current lessee of record with the Bureau of Indian Affairs. For offshore leases, the addressee of record is the current lessee of record with the MMS Offshore Minerals Management Program. The lessee is responsible for notifying the appropriate Government office of any addressee changes.

(4) The addressee of record for serving official correspondence in connection with reviews and audits of payor records is the position title, department name and address, or individual name and address designated, in writing, by the company at the initiation of the audit, or the most recent addressee that was specified, in writing, by the payor.

(5) The addressee of record for serving official correspondence relating to reporting on the ''Report of Sales and Royalty Remittance'' (Form MMS–2014) is the most recent position title, department name and address, or individual name and address specified, in writing, by the payor. The payor is responsible for notifying the Royalty Management Program, in writing, of any addressee changes.

(6) The addressee of record for serving official correspondence in connection with remittances pertaining to rental and bonuses from nonproducing Federal leases is the most recent position title, department name and address, or individual name and address maintained in RMP records. The payor is responsible for notifying RMP, in writing, of any addressee changes.

(7) The addressee of record for serving official correspondence including orders, demands, invoices, or decisions, and other actions identified with payors reporting to the RMP Auditing and Financial System not identified above is the position title, department name and address or individual name and address for the payor identified on the most recent Payor Confirmation Report (Report No. ARR 290R) of a Payor Information Form (PIF) (Form MMS–4025 or Form MMS–4030) returned by RMP to the payor for the Federal or

Indian lease (see 30 CFR 210.51 and 210.201).

(8) In the event official correspondence is applicable to more than one category identified in paragraphs (b)(1) through (7) of this section, MMS may serve the official correspondence in accordance with the requirements of any one paragraph.

(c) *Dates of service.* Except as provided in paragraph (d) of this section, official correspondence is considered served on the date that it is received at the address of record established in accordance with paragraph (b) of this section, as evidenced by a signed receipt of any person at that address. If official correspondence is served both personally and by registered or certified mail, the date of service is the earlier of the two dates, if they are different.

(d) *Constructive service.* (1) If delivery cannot be consummated after reasonable effort at the address of record established in accordance with paragraph (b) of this section, official correspondence will be deemed to have been constructively served 7 days after the date that the document is mailed.

(2) This provision covers such situations as nondelivery because the addressee has moved without filing a forwarding address, the forwarding order had expired, delivery was expressly refused, or the document was unclaimed where the attempt to deliver is substantiated by U.S. Postal Service authorities.

[56 FR 5949, Feb. 14, 1991; 56 FR 9251, Mar. 5, 1991; 58 FR 64903, Dec. 10, 1993]

SUBCHAPTER B—OFFSHORE

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AUTHORITY: 43 U.S.C. 1331, *et seq.*

SOURCE: 53 FR 10690, Apr. 1, 1988, unless otherwise noted.

Subpart A—General

§ 250.0 Authority for information collection.

The information collection requirements in part 250 have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* and assigned clearance numbers as indicated in this section. Send comments regarding the burdens indicated for a specific information collection or any other aspect of the collection of information pursuant to provisions of this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer; Minerals Management Service; Mail Stop 2300; 381 Elden Street; Herndon, Virginia 22070–4817 and the Office of Management and Budget; Paperwork Reduction Project 1010–XXXX; Washington, DC 20503.

(a) The information collection requirements in subpart A, General, have

been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3507 and assigned clearance number 1010–0030. The information is being collected to inform the Minerals Management Service (MMS) of general operations on the Outer Continental Shelf (OCS). The information is used to ensure that operations on the OCS will meet statutory and regulatory requirements, provide for safety and protection of the environment, and result in diligent exploration, development, and production on OCS leases. The requirement to respond is mandatory. Public reporting burden for this collection of information is estimated to average 5 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to the Information Collection Clearance Officer; Minerals Management Service; Mail Stop 2300, 381 Elden Street; Herndon, Virginia 22070–4817, and the Office of Management and Budget; Paperwork Reduction Project 1010–0030; Washington, DC 20503.

(b) The information collection requirements in subpart B, Exploration and Development and Production Plans, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0049. The information is being collected to inform MMS, States, and the public of the planned exploration, development, and production activities on the OCS. The information is used to ensure that operations on the OCS will meet statutory and regulatory requirements, provide for safety and protection of the environment, and result in diligent development of leases. The requirement to respond is mandatory.

(c) The information collection requirements in subpart C, Pollution Prevention and Control, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0057. The information is being collected to inform MMS of potential pollution of the environment. The information is used to identify potential sources of pollution for the purpose of preventing incidents of pollution. The requirement to respond is mandatory.

(d) The information collection requirements in subpart D, Drilling Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0053. The information is being collected to inform MMS of the equipment and procedures lessees plan to use in drilling activities on the OCS. The information is used to ensure that drilling operations are safe and comply with standards to limit pollution. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 5.1 hours per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0053.

(e) The information collection requirements in subpart E, Well-Completion Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0067. The information is being collected to inform MMS of the equipment and procedures lessees plan to use during well-completion operations. The information is used to ensure that well-completion operations are safe and comply with standards to limit pollution. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average .5 hour per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0067.

(f) The information collection requirements in subpart F, Well-Workover Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0043. The information is being collected to inform MMS of the equipment

and procedures lessees plan to use during well-workover operations. The information is used to ensure that well-workover operations are safe and comply with standards to limit pollution. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average .5 hour per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0043.

(g) The information collection requirements in subpart G, Abandonment of Wells, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0079. The information is collected to inform MMS of the lessees' plans for temporarily abandoned wells. The requirement to respond is mandatory.

(h) The information collection requirements in subpart H, Production Safety Systems, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0059. The information is being collected to inform MMS of the equipment and procedures lessees plan to use during the production operations. The information is used to ensure that oil and gas are produced in a manner which provides for safety of operations and protection of the environment. The requirement to respond is mandatory.

(i) The information collection requirements in subpart I, Platforms and Structures, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0058. The information is being collected to inform MMS of the design, fabrication, and installation of platforms on the OCS. The information is used to ensure the structural integrity of platforms installed on the OCS. The requirement to respond is mandatory.

(j) The information collection requirements in subpart J, Pipelines and Pipeline Rights-of-Way, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0050. The information is being collected to inform MMS of the location, design, and operation of pipelines on the OCS. The information is used to ensure that pipelines on the OCS will transport oil and gas in a manner which provides for safety of operations and protection of the environment. The requirement to respond is mandatory.

(k) The information collection requirements in subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0041. The information is being collected to inform MMS of production rates for hydrocarbons produced on the OCS. The information is used to ensure that wells are produced at rates which provide for efficient production of available hydrocarbons. The requirement to respond is mandatory.

(l) The information collection requirements in subpart L, Production Measurement, Surface Commingling, and Security, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0051. The information is being collected to inform MMS of the measurement of production, the commingling of hydrocarbons, and site-security plans and is used to ensure that produced hydrocarbons are measured and commingled in a manner which results in accurate royalty payments. The requirement to respond is mandatory.

(m) The information collection requirements in subpart M, Unitization, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0068. The information is being collected to inform MMS of the unitization of leases. The information is used to ensure that unitization is conducted in a manner which prevents waste, conserves natural resources, and protects correlative rights. The requirement to respond is mandatory.

(n) The information collection requirements in subpart N, Remedies and Penalties, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0038. The information is being collected to inform MMS of evidence relating to violations of provisions of the Act, leases, and OCS rules. The information is used to review violations and determine whether the imposition of a civil penalty is warranted. The requirement to respond

is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 80 hours per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0038.

(o) The information collection requirements for Form MMS–123, Application for Permit to Drill, contained in subpart D, Drilling Operations; subpart E, Well-Completion Operations; and subpart P, Sulphur Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0044. The information is being collected to ascertain the conditions of a drilling site for the purpose of mitigating hazards inherent in drilling operations and to determine whether the drilling operations are being conducted in a safe and environmentally sound manner. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0044.

(p) The information collection requirements for Form MMS–124, Sundry Notices and Reports on Wells, contained in subpart D, Drilling Operations; subpart E, Well-Completion Operations; subpart F, Well-Workover Operations; subpart G, Abandonment of Wells; and subpart P, Sulphur Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0045. The information is being collected to evaluate and approve or disapprove the adequacy of the equipment and/or procedures which the lessee plans to use during the conduct of drilling, production, well-completion, and well-workover operations, including deepening and plugging back and well-abandonment operations, including temporary abandonments where the wellbore will be re-entered and completed or permanently abandoned. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0045.

(q) The information collection requirements for Form MMS–125, Well Summary Report, contained in subpart D, Drilling Operations; subpart E, Well-Completion Operations; subpart F, Well-Workover Operations; and subpart P, Sulphur Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0046. The information is being collected to ensure that MMS's District Supervisors have accurate data and information on the wells under their jurisdiction and to ensure compliance with approved plans. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0046.

(r) The information collection requirements for Form MMS–126, Well Potential Test Report and Request for Maximum Production Rate (MPR), contained in subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0039. The information is being collected to provide MMS with data concerning the production potential of an oil or gas well or the purpose of determining a well maximum production rate. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is 1 hour

per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0039.

(s) The information collection requirements for Form MMS–127, Request for Reservoir Maximum Efficient Rate (MER), contained in subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0018. The information is being collected to determine whether the lessee has correctly classified an oil, gas, or oil-with-associated-gas-cap reservoir, as sensitive or nonsensitive, and to determine a reservoir MER which will prevent detriment to ultimate oil and gas recovery. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0018.

(t) The information collection requirements for Form MMS–128, Semiannual Well Test Report, contained in subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0017. The information is being collected to verify the production capacity of each oil and gas completion and to revise MPR's accordingly. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 2 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0017.

(u) The information collection requirements in Subpart O, Training, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0078. The information is being collected to inform MMS that applicable training programs are sufficient to meet safety and environmental requirements and that the programs are being carried out. The information is used to ensure that workers are properly trained to operate in the OCS. The requirement to respond is mandatory under 43 U.S.C. 1334. Public reporting burden for this collection of information is estimated to average 5 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments submitted relative to this information collection should reference Paperwork Reduction Project 1010–0078.

(v) The information collection requirements in subpart P, Sulphur Operations, have been approved by OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1010–0086. The information is collected to inform MMS about sulphur exploration and development operations in the OCS. The information concerns activities to discover, define, develop, produce, store, measure, and transport sulphur and is used to assure that leasehold operations comply with statutory requirements, provide for operational safety and environmental protection, and will result in proper and timely operations on OCS sulphur leases. The requirement to respond is mandatory in accordance with 43 U.S.C. 1334. Public reporting burden for this information is estimated to average 211 hours per respondent, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Comments relative to this information collection should reference Paperwork Reduction Project 1010–0086.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990; 56 FR 1914, Jan. 18, 1991; 56 FR 2685, Jan. 24, 1991; 56 FR 21954, May 13, 1991; 56 FR 32098, July 15, 1991; 58 FR 49926, Sept. 24, 1993]

§250.1 Documents incorporated by reference.

The documents listed below are incorporated by reference as requirements in this part. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. MMS will publish a notice of any changes in these documents in the FEDERAL REGISTER. The rule change will become effective without notice and prior opportunity to comment if MMS determines that the revisions to a previously incorporated document are minor, result in safety improvements, or represent new industry standard technology and do not impose undue costs on the affected parties. MMS will go through the notice and comment procedure to change the documents incorporated by reference or into this section when MMS proposes to include documents not previously incorporated by reference; a new edition of a document already incorporated by reference introduces controversial issues, or imposes substantial new costs on industry; MMS proposes that a document cover parties not previously affected by the document in question; or MMS believes it would be in the best interest of the public to solicit comments on a new edition. Each document or specific portion thereof is incorporated by reference in the corresponding sections noted. The entire document is incorporated by reference, unless the text of the corresponding sections in this part call 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. In accordance with §250.3, Performance requirements, a lessee may comply with a later edition of a specific document incorporated by reference provided the lessee demonstrates 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 provided the lessee obtains the prior written approval of the authorized MMS official, for such alternate compliance. The list includes the name and address of at least one organization from whom the reference document may be obtained. These documents may be inspected at the Minerals Management Service, 381 Elden Street, Room 3313, Herndon, Virginia, or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. In order to facilitate correlation of the text of the corresponding sections with the list of documents incorporated by reference, the documents are listed in alphanumerical order.

(a) *American Concrete Institute (ACI) Document*. The ACI document listed in this paragraph may be purchased from the American Concrete Institute, P.O. Box 19150, Detroit, Michigan 48219.

(1) American Concrete Institute (ACI) Standard 318–95, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R–95), Incorporated by Reference at: §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), and (e)(2)(i).

(2) ACI Standard 357–R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984, Incorporated by Reference at: §§250.130(g) and 250.138 (c)(2) and (c)(3).

(b) *American Institute of Steel Construction (AISC) Document*. The AISC document listed in this paragraph may be purchased from the American Institute of Steel Construction, Inc., P.O. Box 4588, Chicago, Illinois 60680.

(1) AISC Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, June 1, 1989, with Commentary, Incorporated by Reference at: §250.137 (b)(1)(ii), (c)(4)(iii), and (c)(4)(vii).

(2) [Reserved]

(c) *American National Standards Institute/American Society of Mechanical Engineers (ANSI/ASME) Documents*. The ANSI/ASME documents listed in this paragraph may be purchased from the American National Standards Institute, Attention Sales Department, 1430 Broadway, New York, New York 10018, and from the American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, New York 10017.

(1) The American National Standards Institute/American Society of Mechanical Engineers (ANSI/ASME) Boiler and Pressure Vessel Code, Section I, Power Boilers including Appendices, 1995 Edition, incorporated by Reference at: §§ 250.123 (b)(1) and (b)(1)(i) and 250.292 (b)(1) and (b)(1)(i).

(2) The 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, Incorporated by Reference at: §§ 250.123 (b)(1) and (b)(1)(i) and 250.292 (b)(1) and (b)(1)(i).

(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Divisions 1 and 2, including Nonmandatory Appendices, 1995 Edition, Incorporated by Reference at: §§ 250.123 (b)(1) and (b)(1)(i) and 250.292 (b)(1) and (b)(1)(i).

(4) ANSI/ASME B 31.8–1995, Gas Transmission and Distribution Piping Systems, Incorporated by Reference at: § 250.152(a).

(5) ASME/ANSI SPPE–1–1988 and SPPE–1a–1988, SPPE–1b–1989, SPPE–1c–1989, and SPPE–1d–1990 (addenda), Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations, Incoporated by Reference at § 250.126 paragraphs (c)(2), (e)(1), and (e)(3).

(6) ANSI/ASME B 16.5–1988 (including Errata) and B 16.5a–1992 Addenda, Pipe Flanges and Flanged Fittings, Incorporated by Reference at: § 250.152(b)(2).

(7) ANSI Z88.2–1992, American National Standard for Respiratory Protection, Incorporated by Reference at: §§ 250.67(g)(4)(iv) and (j)(13)(ii).

(d) American Petroleum Institute (API) Documents. The API documents listed in this paragraph may be purchased from the American Petroleum Institute, 1220 L Street, NW., Washington, D.C. 20005. (Paragraphs (d)(21) through (d)(61) of this section refer to the API Manual of Petroleum Measurement Standards (MPMS).

(1) API Spec Q1, Specification for Quality Programs, Third Edition, June 1990, API Stock No. 811–00001, Incorporated by Reference at: § 250.126(c)(3).

(2) 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, Incorporated by Reference at: §§ 250.130(g) and 250.142(a).

(3) API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Third Edition, June 1, 1995, API Stock No. G02D03, Incorporated by Reference at: §§ 250.20(c) and 250.260(g).

(4) API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, Seventeenth Edition, February 1, 1996, API Stock No. G06A17, Incorporated by Reference at: §§ 250.126(c)(3), (e)(2), and (e)(3) and 250.152 (b)(1) and (b)(2).

(5) 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, Incorporated by Reference at: § 250.126(c)(3).

(6) API Spec 6D, Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves), Twenty-first Edition, March 31, 1994, API Stock No. G03200, Incorporated by Reference at: § 250.152(b)(1).

(7) API Spec 14A, Specification for Subsurface Safety Valve Equipment, Ninth Edition, July 1, 1994, API Stock No. G14A09, Incorporated by Reference at: § 250.126 (c)(3), (e)(2), and (e)(3).

(8) API RP 14B, Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fourth Edition, July 1, 1994, with Errata dated June, 1996, API Stock No. G14B04, Incorporated by Reference at: §§ 250.121(e)(4), 250.124(a)(1)(i), and 250.126(d).

(9) 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, Incorporated by References at §§ 250.122 (b) and (e)(2); 250.123 (a), (b)(2)(i), (b)(4), (b)(5)(i), (b)(7), (b)(9)(v), and (c)(2); 250.124 (a) and (a)(5); 250.152(d); 250.154(b)(9); 250.291 (c) and (d)(2); 250.292 (b)(2) and (b)(4)(v); and 250.293(a).

(10) 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, Incorporated by Reference at: § 250.126 (c)(3), (e)(2), and (e)(3).

(11) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1, 1991, API Stock No. G07185, Incorporated by Reference at: §§ 250.122(e)(3) and 250.291 (b)(2) and (d)(3).

(12) 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, Incorporated by Reference at: §§ 250.53(c), 250.123(b)(9)(v), and 250.292(b)(4)(v).

(13) 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, Incorporated by Reference at: §§ 250.123 (b)(8) and (b)(9)(v) and 250.292 (b)(3) and (b)(4)(v).

(14) 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, Incorporated by Reference at: §§ 250.122(d) and 250.126(d).

(15) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, First Edition, June 1, 1991, API Stock No. G06005, Incorporated by Reference at: §§ 250.53(b), 250.122(e)(4)(i), 250.123(b)(9)(i), 250.291 (b)(3) and (d)(4)(i), and 250.292(b)(4)(i).

(16) API Standard 2545, Method of Gauging 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, Incorporated by Reference at: § 250.180(f)(2)(ii)(C).

(17) 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, Incorporated by Reference at: § 250.180(f)(2)(i)(C).

(18) 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, Incorporated by Reference at: § 250.180(f)(2)(i)(C).

(19) 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, Incorporated by Reference at: § 250.180(f)(2)(i)(C).

(20) API RP 2556, Correcting Gauge Tables for Incrustation, Second Edition, August 1993, API Stock No. H25560, Incorporated by Reference at: § 250.180(f)(2)(i)(C).

(21) Manual of Petroleum Management Standard (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, Incorporated by Reference at: § 250.180(f)(2)(i)(A).

(22) 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, Incorporated by Reference at: § 250.180(f)(2)(i)(B).

(23) 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, Incorporated by Reference at: § 250.180(f)(2)(ii)(A).

(24) 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, Incorporated by Reference at: § 250.180(f)(2)(ii)(B).

(25) MPMS, Chapter 4, Proving Systems, section 1, Introduction, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30081, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(26) MPMS, Chapter 4, section 2, Conventional Pipe Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30082, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(27) MPMS, Chapter 4, section 3, Small Volume Provers, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30083, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(28) MPMS, Chapter 4, section 4, Tank Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30084, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(29) MPMS, Chapter 4, section 5, Master-Meter Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30085, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(30) MPMS, Chapter 4, section 6, Pulse Interpolation, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30086, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(31) MPMS, Chapter 4, section 7, Field-Standard Test Measures, First Edition, October 1988, API Stock No. H30087, Incorporated by Reference at: § 250.180 (c)(6)(i) and (d)(3)(iv).

(32) MPMS, Chapter 5, Metering, section 1, General Considerations for Measurement by Meters, Third Edition, September 1995, API Stock No. H05013, Incorporated by Reference at: § 250.180(c)(6)(ii).

(33) MPMS, Chapter 5, section 2, Measurement of Liquid Hydrocarbons by Displacement Meters, Second Edition, November 1987, reaffirmed October 1992, API Stock No. H30102, Incorporated by Reference at: § 250.180(c)(6)(ii).

(34) MPMS, Chapter 5, section 3, Measurement of Liquid Hydrocarbons by Turbine Meters, Third Edition, September 1995, API Stock No. H05033, Incorporated by Reference at: § 250.180(c)(6)(ii).

(35) MPMS, Chapter 5, section 4, Accessory Equipment for Liquid Meters, Third Edition, September 1995, with Errata, March, 1996, API Stock No. H05043, Incorporated by Reference at: § 250.180(c)(6)(ii).

(36) 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, Incorporated by Reference at: § 250.180(c)(6)(ii).

(37) MPMS, Chapter 6, Metering Assemblies, section 1, Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991, API Stock No. H30121, Incorporated by Reference at: § 250.180(c)(6)(iii)(A).

(38) MPMS, Chapter 6, section 6, Pipeline Metering Systems, Second Edition, May 1991,

API Stock No. H30126, Incorporated by Reference at: § 250.180(c)(6)(iii)(B).

(39) MPMS, Chapter 6, section 7, Metering Viscous Hydrocarbons, Second Edition, May 1991, API Stock No. H30127, Incorporated by Reference at: § 250.180(c)(6)(iii)(C).

(40) MPMS, Chapter 7, Temperature Determination, section 2, Dynamic Temperature Determination, Second Edition, March 1995, API Stock No. H07022, Incorporated by Reference at: § 250.180 (c)(6)(iv)(A) and (f)(2)(iii)(A).

(41) MPMS, Chapter 7, section 3, Static Temperature Determination Using Portable Electronic Thermometers, First Edition, July 1985, reaffirmed March 1990, API Stock No. H30143, Incorporated by Reference at: § 250.180 (c)(6)(iv)(B) and (f)(2)(iii)(B).

(42) 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, Incorporated by Reference at: § 250.180 (c)(6)(v) and (f)(2)(iv).

(43) 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, Incorporated by Reference at: § 250.180 (c)(6)(v) and (f)(2)(iv).

(44) 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, Incorporated by Reference at: § 250.180 (c)(6)(vi)(A) and (f)(2)(v)(A).

(45) 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, Incorporated by Reference at: § 250.180 (c)(6)(vi)(B) and (f)(2)(v)(B).

(46) 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, Incorporated by Reference at: § 250.180 (c)(6)(vii)(A) and (f)(2)(vi)(A).

(47) 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, Incorporated by Reference at: § 250.180 (c)(6)(vii)(B) and (f)(2)(vi)(B).

(48) 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, Incorporated by Reference at: § 250.180 (c)(6)(vii)(C) and (f)(2)(vi)(C).

(49) 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, Incorporated by Reference at: § 250.180 (c)(6)(vii)(D) and (f)(2)(vi)(D).

(50) 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, Incorporated by Reference at: § 250.180 (c)(6)(viii)(A), (d)(3)(v)(B), and (f)(2)(vii).

(51) 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, Incorporated by Reference at: § 250.180(c)(6)(viii)(B).

(52) 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, Incorporated by Reference at: § 250.180(c)(6)(viii)(C).

(53) 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, Incorporated by Reference at: § 250.180(c)(6)(viii)(D).

(54) MPMS, Chapter 11.2.3, Water Calibration of Volumetric Provers, First Edition, August 1984, reaffirmed, May 1996, API Stock No. H27310, Incorporated by Reference at: § 250.180(d)(3)(iv).

(55) 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, Incorporated by Reference at: § 250.180 (c)(6)(ix), (d)(3)(v)(A), and (d)(3)(v)(C).

(56) 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, Incorporated by Reference at: § 250.181(c)(1).

(57) 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, Incorporated by Reference at: §250.181(c)(1).

(58) 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, Incorporated by Reference at: §250.181(c)(1).

(59) 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 24.5–1981, order from Gas Processors Association, 6526 East 60th Street, Tulsa, Oklahoma 74145, Incorporated by Reference at: §250.181(c)(1).

(60) MPMS, Chapter 14, section 6, Continuous Density Measurement, Second Edition, April 1991, API Stock No. H30346, Incorporated by Reference at: §250.181(c)(1).

(61) MPMS, Chapter 14, section 8, Liquefield Petroleum Gas Measurement, First Edition, February 1983, reaffirmed May 1996, API Stock No. H30348, Incorporated by Reference at: §250.181(c)(1).

(e) *American Society for Testing and Materials (ASTM) Documents.* The ASTM documents listed below may be purchased from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

(1) ASTM Standard C33–93, Standard Specification for Concrete Aggregates including Nonmandatory Appendix, Incorporated by Reference at §250.138(b)(4)(i).

(2) ASTM Standard C94–96, Standard Specification for Ready-Mixed Concrete, Incorporated by Reference at §250.138(e)(2)(i).

(3) ASTM Standard C150–95a, Standard Specification for Portland Cement, Incorporated by Reference at §250.138(b)(2)(i).

(4) ASTM Standard C330–89, Standard Specification for Light weight Aggregates for Structural Concrete, Incorporated by Reference at §250.138(b)(4)(i).

(5) ASTM Standard C595–94, Standard Specification for Blended Hydraulic Cements, Incorporated by Reference at §250.138(b)(2)(i).

(f) *American Welding Society (AWS) Documents.* The AWS documents listed in this paragraph may be purchased from the American Welding Society, 550 NW. LeJeune Road, P.O. Box 351040, Miami, Florida 33135.

(1) D1.1–96, Structural Welding Code—Steel, 1996, including Commentary, Incorporated by Reference at: §250.137(b)(1)(i).

(2) D1.4–79, Structural Welding Code—Reinforcing Steel, 1979, Incorporated by Reference at: §250.138(e)(3)(ii).

(g) *National Association of Corrosion Engineers (NACE) Documents.* The NACE documents listed in this paragraph may be purchased from the National Association of Corrosion Engineers, P.O. Box 218340, Houston, Texas 77218.

(1) NACE Standard MR.01–75–96, Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment, January 1996, Incorporated by Reference at: §250.67(p)(2).

(2) NACE Standard RP 0176–94, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production, Incorporated by Reference at §250.137(d).

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 10617, Mar. 22, 1990; 55 FR 37710, Sept. 13, 1990; 55 FR 47752, Nov. 15, 1990; 55 FR 51415, Dec. 14, 1990; 56 FR 32098, July 15, 1991; 61 FR 60022, Nov. 26, 1996; 62 FR 3795, Jan. 27, 1997; 62 FR 33156, June 18, 1997]

§250.2 Definitions.

Terms used in this part shall have the meanings given in the Act and as defined below:

Act means the OCS Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

Affected State means, with respect to any program, plan, lease sale, or other activity proposed, conducted, or approved pursuant to the provisions of the Act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installation or other device permanently or temporarily attached to the seabed;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary of the Interior (Secretary) as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes

in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the OCS; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents to the marine or coastal environment in the event of any oil spill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

Air pollutant means any airborne agent or combination of agents for which the Environmental Protection Agency (EPA) has established, pursuant to section 109 of the Clean Air Act, national primary or secondary ambient air quality standards.

Analyzed geological information means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analysis, laboratory analysis of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

Archaeological resource means any material remains of human life or activities that are at least 50 years of age and that are of archaeological interest.

Attainment area means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) not to exceed any primary or secondary ambient air quality standards established by EPA.

Best available control technology (BACT) means an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account energy, environmental and economic impacts, and other costs. The BACT shall be verified on a case-by-case basis by the Regional Supervisor and may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone.

Coastal zone means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder) strongly influenced by each other and in proximity to the shorelands of the several coastal States. The coastal zone includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches. The coastal zone extends seaward to the outer limit of the U.S. territorial sea and extends inland from the shorelines to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority in section 305(b)(1) of the Coastal Zone Management Act (CZMA) of 1972.

Competitive reservoir means a reservoir in which there are one or more well completions on each of two or more leases from which the lessees plan future production.

Correlative rights when used with respect to lessees of adjacent tracts, means the right of each lessee to be afforded an equal opportunity to explore for, develop, and produce, without waste, minerals from a common source.

Data means facts and statistics or samples which have not been analyzed or processed.

Development means those activities which take place following discovery of minerals in paying quantities, including geophysical activity, drilling, platform construction, and operation of all onshore support facilities, and which are for the purpose of ultimately producing the minerals discovered.

Director means the Director of MMS of the U.S. Department of the Interior.

District Supervisor means the MMS officer with authority and responsibility for a district within an MMS Region.

Eastern Gulf of Mexico means all OCS areas in the Gulf of Mexico deemed by the Director to be adjacent to the State of Florida.

Emission offsets means emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan or Development and Production Plan.

Enhanced recovery operations means pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

Existing facility as used in § 250.45 is an OCS facility described in an Exploration Plan or a Development and Production Plan submitted or approved prior to June 2, 1980.

Exploration means the process of searching for minerals, including:

(1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of such minerals;

(2) Any drilling, whether on or off known geological structures, including the drilling of a well in which a discovery of oil or natural gas in paying quantities is made and the drilling of any additional delineation well after such discovery that is needed to delineate any reservoir and to enable the lessee to determine whether to proceed with development and production; and

(3) Any drilling for sulphur, including the drilling of a well that indicates a sulphur deposit is present and the drilling of additional delineation wells needed to outline the sulphur deposit and enable the lessee to determine whether to proceed with development and production operations.

Facility as used in § 250.45 concerning air quality means any installation or device permanently or temporarily attached to the seabed which is used for exploration, development, and production activities for oil, gas, or sulphur and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be considered to be a single facility if the installations or devices are directly related to the production of oil or gas at a single site. Any vessel used to transfer production from an offshore facility shall be considered part of the facility while physically attached to it.

Facility as used in § 250.67(b) concerning hydrogen sulfide (H_2S) means a vessel, a structure, or an artificial island used for drilling, well-completion, well-workover, and/or production operations.

Gas reservoir means a reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

Gas-well completion means a well completed in a gas reservoir or in the gas-cap of an oil reservoir with an associated gas cap.

Governor means the Governor of a State, or the person or entity designated by, or pursuant to, State law to exercise the powers granted to such Governor pursuant to the Act.

Human environment means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities occurring on the OCS.

Information when used without a qualifying adjective, includes analyzed geological information, processed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

Interpreted geological information means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

Interpreted geophysical information means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

Lease means any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, minerals or the area covered by that authorization, whichever is required by the context.

Lease term pipelines are those pipelines owned and operated by a lessee or operator and are wholly contained within the boundaries of a single lease, unitized leases, or contiguous (not cornering) leases of that lessee or operator.

Lessee means the party authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in this part.

Major Federal action means any action or proposal by the Secretary which is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act of 1969 (i.e., an action which will have a significant impact on the quality of the human environment requiring preparation of an Environmental Impact Statement pursuant to section 102(2)(C) of the National Environmental Policy Act).

Marine environment means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the OCS.

Material remains means physical evidence of human habitation, occupation, use, or activity, including the site, location, or context in which such evidence is situated.

Maximum efficient rate (MER) means the maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

Maximum production rate means the approved maximum daily rate at which oil or gas may be produced from a specified oil-well or gas-well completion.

Minerals includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals which are authorized by an act of Congress to be produced from ''public lands'' as defined in section 103 of the Federal Land Policy and Management Act of 1976.

Nonattainment area means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) to exceed any primary or secondary ambient air quality standard established by EPA.

Nonsensitive reservoir means a reservoir in which ultimate recovery is not decreased by high reservoir production rates.

Of archaeological interest means capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics through the application of scientific or scholarly techniques, such as controlled observation, contextual measurement, controlled collection, analysis, interpretation, and explanation.

Oil reservoir means a reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

Oil reservoir with an associated gas cap means a reservoir that contains hydrocarbons in both a liquid and gaseous (two-phase) state.

Oil-well completion means a well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

Operator means the individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The operator may be a lessee, designated agent of the lessees, or holder of operating rights under an approved operating agreement.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person includes, in addition to a natural person, an association, a State, a political subdivision of a State, or a private, public, or municipal corporation.

Pipelines are the piping, risers, and appurtenances installed for the purpose of transporting oil, gas, sulphur, and produced waters.

Processed geological information means data collected under a permit or a lease

which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

Production means those activities which take place after the successful completion of any means for the removal of minerals, including such removal, field operations, transfer of minerals to shore, operation monitoring, maintenance, and work-over operations.

Projected emissions means emissions, either controlled or uncontrolled, from a source or sources.

Right-of-way pipelines are those pipelines which: (1) Are contained within the boundaries of a single lease or unitized leases but are not owned and operated by a lessee or operator of that lease or unit, (2) are contained within the boundaries of contiguous (not cornering) leases which do not have a common lessee or operator, (3) are contained within the boundaries of contiguous (not cornering) leases which have a common lessee or operator but are not owned and operated by that common lessee or operator, or (4) are contained within a block(s) which is unleased.

Regional Director means the MMS officer with responsibility and authority for a Region within MMS.

Regional Supervisor means the MMS officer with responsibility and authority for operations or other designated program functions within an MMS Region.

Routine operations means for the purposes of subpart F, any of the following operations conducted on a well with the tree installed: (1) cutting paraffin; (2) removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations; (3) bailing sand; (4) pressure surveys; (5) swabbing; (6) scale or corrosion treatment; (7) caliper and gauge surveys; (8) corrosion inhibitor treatment; (9) removing or replacing subsurface pumps; (10) through-tubing logging (diagnostics); (11) wireline fishing; and (12) setting and retrieving other subsurface flow-control devices.

Sensitive reservoir means a reservoir in which ultimate recovery is decreased by high reservoir production rates. A high reservoir production rate is one which exceeds the MER.

Significant archaeological resource means those archaeological resources that meet the criteria of significance for eligibility to the National Register of Historic Places as defined in 36 CFR 60.4.

Waste of oil, gas, or sulphur means (1) the physical waste of oil, gas, or sulphur; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil, gas, or sulphur well(s) in a manner which causes or tends to cause a reduction in the quantity of oil, gas, or sulphur ultimately recoverable under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or (4) the inefficient storage of oil.

Well-completion operations means the work conducted to establish production from a well after the production-casing string has been set, cemented, and pressure-tested.

Well-control fluid means drilling mud, completion fluid, or workover fluid as appropriate to the particular operation being conducted.

Workover operations means the work conducted on wells after the initial well-completion operation for the purpose of maintaining or restoring the productivity of a well.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 32098, July 15, 1991; 59 FR 53093, Oct. 21, 1994; 62 FR 3795, Jan. 27, 1997]

§250.3 Performance requirements.

(a) Nothing in this part shall preclude the use of new or alternative techniques, procedures, equipment, or activities other than those prescribed in the regulations of this part; if such other techniques, procedures, equipment, or activities afford a degree of protection, safety, or performance equal to or better than that intended to be achieved by the regulations of this part, provided the lessee or right-of-way holder obtains the prior written

approval of the District or Regional Supervisor, as appropriate, for the use of such new or alternative techniques, procedures, equipment, or activities.

(b) The appropriate MMS official may prescribe or approve departures from the operating requirements of the regulations of this part when such departures are necessary for the proper control of a well, the facilitation of the proper development of a lease, the conservation of natural resources, or the protection of life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989]

§ 250.4 Jurisdiction.

(a) Subject to the supervisory authority of the Secretary, drilling and production operations, handling, measurement, transportation of production, and other operations and activities conducted pursuant to a lease or right-of-way by or on behalf of a lessee or right-of-way holder are subject to the regulations in this part and are under the jurisdiction of the Director.

(b) In the exercise of that jurisdiction, the Director is authorized and directed to act upon the requests, applications, and notices submitted under the regulations in this part to issue either written or oral orders to govern lease and right-of-way operations and to require compliance with applicable laws, regulations, and lease terms so that all operations conform to sound conservation practice and are conducted in a manner which will preserve, protect, and develop mineral resources of the OCS in a manner which is consistent with the following need to:

(1) Make such resources available to timely meet the Nation's energy needs;

(2) Balance orderly energy resource development with protection of the human, marine, and coastal environments;

(3) Ensure the public a fair and equitable return on the resources of the OCS;

(4) Preserve and maintain free enterprise competition; and

(5) Minimize or eliminate conflicts between the exploration, development, and production of oil and natural gas and the recovery of other resources such as fish and shellfish.

§ 250.5 Functions.

The Director, in accordance with the regulations in this part, shall accomplish the following:

(a) Regulate all operations conducted under a lease, right of use and easement, or right-of-way to promote orderly exploration, development, and production of mineral resources and to prevent unreasonable harm or damage to, or waste of, any natural resource (including any mineral deposits in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

(b) Require on all new drilling and production operations and, whenever practicable, existing operations, the use of BAST, which the Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental cost of utilizing such technologies.

(c) Conduct a scheduled onsite inspection at least once a year of each offshore facility which is subject to environmental or safety regulations promulgated pursuant to the Act. The inspection shall be to determine that environmental protection equipment and safety equipment designed to prevent or ameliorate blowouts, fires, spillages, or other major accidents have been installed and are operating properly in accordance with the requirements of this part.

(d) Conduct periodic onsite inspection without advance notice to the operator of such facility as determined necessary to assure compliance with applicable regulations.

(e) Cooperate and consult with or solicit advice from affected States, executives of affected local governments, other interested parties, and relevant Departments and Agencies of the Federal Government.

(f) Identify for those activities under the jurisdiction of the Director those

States which are deemed to be affected States.

§250.6 Oral approvals.

(a) The appropriate MMS official may give an oral approval whenever the regulations in this part require a lessee or other applicant to obtain such official's approval before commencing an operation or activity. If an oral approval is given in response to an oral request, the lessee or applicant shall confirm the oral request by submitting a written request within 72 hours of the oral approval and the MMS official shall approve that request subject to any conditions that were placed upon the oral approval. In the event a written application is given oral approval by an MMS official, the MMS official shall forward the approval and any conditions placed theron to the applicant.

(b) The appropriate MMS official may give oral orders to lessees in connection with requirements of this part whenever circumstances do not permit the time needed to prepare and issue such orders in writing. Oral orders shall be confirmed in writing by the appropriate MMS official.

§250.7 Right of use and easement.

(a) In addition to the rights and privileges granted to a lessee under a lease issued or maintained under the Act, the Regional Supervisor may grant a lessee, subject to conditions prescribed by the Regional Supervisor, a right of use and easement on the OCS to construct and maintain off the lease platforms, artificial islands, and all installations and other devices which are permanently or temporarily attached to the seabed and which are used for conducting exploration, development, and production activities or other operations on or off the lease which are related to such activities. Rights of use and easement on the OCS shall be issued and exercised in accordance with the provisions of this section.

(b) A right of use and easement, if on an area subject to any lease issued or maintained under the Act, shall be granted only after the holder of the lease has been notified by the applicant and afforded an opportunity to comment on the application.

(c) The Regional Supervisor shall require compliance with subpart I and MMS approval for all platforms, artificial islands, and installations and other devices permanently or temporarily attached to the seabed as a condition of the granting of a right of use and easement under paragraph (a) of this section or as authorized under any lease issued or maintained under the Act.

(d) The right granted by a right of use and easement shall be exercised in accordance with the requirements placed upon lessees by the regulations in this part.

(e) A right of use and easement shall be exercised only in a manner which does not interfere unreasonably with operations of any lessee under a lease.

(f) Once a right of use and easement has been exercised, the right shall continue, beyond the termination of any lease on which it may be situated, as long as it can be demonstrated to the Regional Supervisor that the right of use and easement is maintained by the holder of the right and serves the purpose specified in the grant. If the right of use and easement extends beyond the termination of any lease on which the right of use and easement may be situated or on an unleased portion of the OCS, the rights of all subsequent lessees shall be subject to such right of use and easement.

§250.8 Designation of operator.

This section explains the requirement for designation of an operator to conduct operations on a lease where the operator is not the sole lessee (record title owner) and owner of operating rights.

(a) Each record title owner (lessee) or operating rights owner for a lease must provide the Regional Supervisor a designation of operator in each case where someone other than an exclusive record title and operating rights owner will conduct lease operations. The designated operator must not begin operations on the lease until the Regional Supervisor receives the designation of operator.

(1) This designation of operator is authority for the operator to act on behalf of each lessee and operating rights

owner and to fulfill each of their obligations under the Act, the lease, and the regulations in this part.

(2) You must immediately notify the Regional Supervisor in writing if you terminate the designation of operator.

(3) If you terminate a designation of operator or a controversy develops between you and your designated operator, you and the operator must protect the lessor's interests.

(4) You or the lease operator must immediately notify the Regional Supervisor in writing of any change of address.

(b) Lessees and operating rights owners are jointly and severally responsible for performing nonmonetary lease obligations, unless otherwise provided in the regulations in this chapter. If the designated operator fails to perform any obligation under the lease or the regulations in this chapter, the Regional Director may require any or all of the co-lessees and operating rights owners to bring the lease into compliance.

[62 FR 27954, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27954, May 22, 1997, § 250.8 was revised, effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 250.8 Designation of operator.

In all cases where operations are not conducted by an exclusive owner of record, a designation of operator shall be submitted to the Regional Supervisor prior to the commencement of operations. This designation will be accepted as authority for the operator, or the operator's local representative, to act on behalf of the lessee and to fulfill the lessee's obligations under the Act and the regulations in this part. All changes of address and any termination of the authority of the operator shall be reported immediately, in writing, to the Regional Supervisor. In case of a termination or in the event of a controversy between the lessee and the designated operator, both the lessee and the operator will be required to protect the interests of the lessor.

§ 250.9 Local agent.

When required by the Regional Supervisor or at the option of the lessee, the lessee shall designate a representative empowered to receive notices and comply with orders issued pursuant to the regulations in this part.

§ 250.10 Suspension of production or other operations.

(a) The Regional Supervisor may, on the Regional Supervisor's initiative or at the request of the lessee, suspend or temporarily prohibit production or any other operation or activity on all or any part of a lease (suspension) when the Regional Supervisor determines that such suspension is in the national interest and that the suspension is necessary as follows:

(1) To facilitate proper development of a lease including reasonable time to construct production facilities;

(2) To allow for the construction or negotiation for use of transportation facilities;

(3) To allow reasonable time to enter into a sales contract for oil, gas, or sulphur, when good faith efforts to secure such contract(s) are being made;

(4) To allow reasonable time to commence drilling operations when good faith efforts are prevented by reasons beyond the lessee's control, such as unexpected weather or unavoidable accidents; or

(5) To avoid continued operations which would result in premature abandonment of a producing well(s) or would not be economic.

(b) The Regional Supervisor may also direct or, at the request of the lessee, approve a suspension of any operation or activity, including production, because of the following:

(1) The lessee failed to comply with a provision of any applicable law, regulation, or order, or provision of a lease or permit;

(2) There is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment;

(3) The suspension is in the interest of national security or defense;

(4) The suspension is necessary for the implementation of the requirements of the National Environmental Policy Act or to conduct an environmental analysis;

(5) The suspension is necessary to facilitate the installation of equipment necessary for safety and environmental reasons;

(6) The suspension is necessary to allow for inordinate delays encountered by the lessee in obtaining required permits or consents, including administrative or judicial challenges or appeals; or

(7) The suspension is necessary to comply with judicial decrees prohibiting production or any other operation or activity, or the permitting of those activities, effective the date set by the court for that prohibition.

(c) If provided for by lease stipulation, the Regional Supervisor shall suspend or temporarily prohibit production or any other operation or activity pursuant to a lease when such lease is in water depths of 400 to 900 meters, provided that the suspension or temporary prohibition shall be for such period of time as is necessary to complete the activities described in a Development and Production Plan approved by the Regional Supervisor in accordance with § 250.34. However, in no case shall the suspension under this paragraph be for periods of time which exceed a total of 5 years.

(d)(1) A suspension of production pursuant to paragraph (a) (1), (2), or (3) of this section may not be issued unless a well on the lease for which the suspension is requested has been drilled and determined to be producible in paying quantities in accordance with § 250.11.

(2) For sulphur operations, a suspension of production pursuant to paragraph (a) (1), (2), or (3) of this section may not be issued unless a deposit on the lease for which the suspension is requested has been drilled and determined to be producible in paying quantities in accordance with 30 CFR 250.253.

(e) Except as provided in paragraph (c) of this section, suspensions under this section may be granted for periods of time each of which shall not exceed 5 years.

(f) When the Regional Supervisor orders or approves a suspension pursuant to paragraph (a), (b), or (c) of this section, the term of the lease shall be extended for a period of time equal to the period that the suspension is in effect, except that no lease shall be so extended when the suspension is the result of the lessee's gross negligence or willful violation of the lease or governing regulations.

(g) The Regional Supervisor may, at any time within the period prescribed for a suspension issued pursuant to paragraph (b)(2) of this section, require the lessee to submit a plan for approval, disapproval, or modification in accordance with subpart B, Exploration and Development and Production Plans.

(h)(1) When the Regional Supervisor directs or grants a suspension pursuant to paragraph (b)(2) of this section, the Regional Supervisor may require the lessee to conduct a site-specific study(s) to identify and evaluate the cause(s) of the hazard(s) generating the suspension, the potential damage from the hazard(s), and the measures available for mitigating the hazard(s). A reasonable scope of the study(s) shall be approved or prescribed by the Regional Supervisor. The lessee shall furnish copies and all results of the study(s) to the Regional Supervisor. The cost of the study(s) shall be borne by the lessee unless the Regional Supervisor arranges for the cost of the study(s) to be borne by a party(s) other than the lessee. The Regional Supervisor shall make such results available to interested parties and to the public.

(2) On the basis of the results of the study or studies conducted in accordance with paragraph (h)(1) of this section and other information available to and identified by the Regional Supervisor, the Regional Supervisor shall require the lessee to take appropriate measures to mitigate or avoid the damage or potential damage, which resulted in the suspension or temporary prohibition of production or of any other operation or activity, as a condition for permitting the resumption of exploration, development, or production activities on the lease. The lessee shall submit, when deemed appropriate by the Regional Supervisor, a revised Exploration Plan or a revised Development and Production Plan in accordance with § 250.34 of this part. The revised plan shall incorporate the mitigating measures required by the Regional Supervisor. In choosing between alternative mitigating measures, the Regional Supervisor will balance the cost of the required measures against

the reduction or potential reduction in damage or threat of damage or harm to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment.

(i) The lessee must submit with a request for a suspension of production the reasons for requesting the suspension, a schedule of work leading to the commencement or restoration of production or any other operation or activity, and any other information the Regional Supervisor may require.

(j) Any suspension may be terminated at any time when the Director determines that the circumstances which justified the granting of the suspension no longer exist. When the Director terminates a suspension prior to the end of the period of time for which the suspension was originally granted, the Director shall specify in the notice of termination the reason(s) for the termination and the effective date for the termination of the suspension.

(k) Any suspension shall terminate automatically upon the commencement of production or any other suspended operation or activity.

[53 FR 10690, Apr. 1, 1988 as amended at 56 FR 32099, July 15, 1991]

§ 250.11 Determination of well producibility.

Upon receiving a written request from the lessee, the District Supervisor will determine whether a well is capable of producing in paying quantities (production of oil, gas, or both in quantities sufficient to yield a return in excess of the costs, after completion of the well, of producing the hydrocarbons at the wellhead.) Such a determination shall be based upon the following:

(a) A production test for oil wells shall be of at least 2 hours' duration following stabilization of flow. A deliverability test for gas wells shall be of at least 2 hours' duration following stabilization of flow or a four-point backpressure test. The lessee shall provide the District Supervisor a reasonable opportunity to witness all tests. Test data accompanied by the lessee's affidavit, or third-party test data, may be accepted in lieu of a witnessed test, provided prior approval is obtained from the District Supervisor.

(b) In the Gulf of Mexico OCS Region, the following shall also be considered collectively as reliable evidence that a well is capable of producing oil or gas in paying quantities:

(1) A resistivity or induction electric log of the well showing a minimum of 15 feet of producible sand in one section that does not include any interval which appears to be water-saturated. In some cases, wells with less than 15 feet of producible sand in one section may be approved by the District Supervisor. All of the section counted as producible shall exhibit the following properties:

(i) Electrical spontaneous potential exceeding 20-negative millivolts beyond the shale base line. If mud conditions prevent a 20-negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water-bearing sand may be substituted.

(ii) A minimum true resistivity ratio of the producible section to the nearest clean water-bearing sand of at least 5:1.

(2) A log indicating sufficient porosity in the producible section.

(3) Sidewall cores and core analyses which indicate that the section is capable of producing oil or gas or evidence that an attempt was made to obtain such cores.

(4) A wireline formation test and/or mud-logging analysis which indicates that the section is capable of producing oil or gas, or evidence that an attempt was made to obtain such tests.

§ 250.12 Cancellation of leases.

(a)(1) The Secretary may terminate a suspension and cancel a lease as follows after notice and opportunity for a hearing when:

(i) Continued activity pursuant to the lease or permit would probably cause serious harm or damage to life (including fish and other aquatic life), property, other mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment;

(ii) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time;

(iii) The advantages of cancellation outweigh the advantages of continuing the lease or permit in force; and

(iv) The suspension has been in effect for at least 5 years, or the termination of suspension and lease cancellation are at the request of the lessee.

(2) If a lease is cancelled under this section or under part 256 of this title, the lessee shall be entitled to compensation pursuant to the provisions of this section.

(b) Whenever an Exploration Plan is disapproved because the Regional Supervisor determines that approval of the activities called for in the plan would probably cause serious harm or damage to life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), the national security or defense, or to the marine, coastal, or human environment and the proposed activity cannot be modified to avoid these dangers, the Secretary, once the primary lease term has been extended continuously for a period of 5 years following the disapproval or upon request of the lessee at an earlier time, may terminate the suspension or temporary prohibition and cancel the lease, and the lessee shall be entitled to compensation pursuant to paragraph (f) of this section.

(c)(1) Where a Development and Production Plan is submitted before the subsequent approval of a Coastal Zone Management (CZM) program for an affected State, pursuant to the CZMA, and the plan is disapproved by the Regional Supervisor pursuant to § 250.34(k)(3)(ii), the following may occur:

(i) The term of the lease shall be duly extended and, at any time within 5 years after such disapproval, the lessee may reapply for approval of the same or a modified plan, and the Regional Supervisor shall approve, disapprove, or require modification of the plan in accordance with the provisions in § 250.34.

(ii) Upon expiration of the 5-year period described in paragraph (c)(1)(i) of this section or, at the Secretary's discretion, at an earlier time upon request of the lessee, if the Regional Supervisor has not approved a plan or required the lessee to submit a Development and Production Plan for approval or modification, the Secretary shall cancel the lease, and the lessee shall be entitled to compensation pursuant to paragraph (f) of this section.

(d) The lessee shall not be entitled to compensation when a lease expires.

(e) The lessee shall not be entitled to compensation when a lease is cancelled where the following circumstances exist:

(1) A Development and Production Plan submitted after approval of a State's CZM program, pursuant to the CZMA, is disapproved because the lessee does not receive concurrence by the State pursuant to section 307(c)(3)(B)(i) or (ii) of the CZMA, and the Secretary of Commerce does not make the finding authorized by section 307(c)(3)(B)(iii) of the CZMA;

(2) A lessee fails to submit a Development and Production Plan in accordance with § 250.34 or fails to comply with an approved plan;

(3) The owner of a nonproducing lease fails to comply with a provision of the Act, the lease, or the regulations issued under the Act, and the default continues for a period of 30 days after the mailing of a notice by registered letter to the lessee;

(4) A Development and Production Plan is disapproved because of a failure to demonstrate compliance with the requirements of applicable Federal law, or

(5) A producing lease is forfeited or is cancelled pursuant to section (5)(d) of the Act.

(f) Cancellation of a lease under paragraphs (a), (b), and (c) of this section shall entitle the lessee to receive such compensation as the lessee shows the Director as being equal to the lesser of the following:

(1) The fair value of the cancelled rights as of the date of cancellation, taking into account both anticipated revenues from the lease and costs reasonably anticipated on the lease, including costs of compliance with all applicable regulations and operating orders and liability for cleanup costs or damages, or both, in the case of an oil spill; or

(2) The excess, if any, over the lessee's revenues from the lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for the lease and all direct expenditures made by the lessee after the date of issuance of the lease and in connection with exploration or development, or both, pursuant to the lease (plus interest on this consideration and expenditures from date of payment to date of reimbursement), except as follows:

(i) With respect to leases issued before September 18, 1978, compensation shall be equal to the amount specified in paragraph (f)(1) of this section, and

(ii) In the case of jointly held leases which are cancelled due to the failure of one or more partners to exercise due diligence, innocent party(s) shall have the right to seek damages for losses from the responsible party(s) and the right to acquire the interests of the negligent party(s) and be issued the lease in question.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989]

§ 250.13 How Does Production, Drilling, or Well-reworking Affect Your Lease Term?

(a) Your lease expires at the end of its primary term unless you are producing or conducting drilling or well-reworking operations on your lease. *See* § 256.37(b) of this title. Also, any drilling or well-reworking program must be part of a plan that has as its objective continuous production on the lease. For purposes of this section, the term ''operations'' means production, drilling, or well-reworking.

(b) If you stop conducting operations during the last 180 days of the primary lease term, your lease will remain in effect beyond the primary term only if you:

(1) Resume operations on the lease no later than 180 days after the operations ended; or

(2) Ask MMS for a suspension of operations or production under 30 CFR 250.10 before the 180th day after you stop operations, and thereafter receive the Regional Supervisor's approval; or

(3) Receive a directed suspension of operations or production from the Regional Supervisor under 30 CFR 250.10 before the 180th day after you stop operations.

(c) If you stop conducting operations on a lease that has continued beyond its primary term, then your lease will expire unless you comply with either paragraph (b)(1), (b)(2), or (b)(3) of this section.

(d) You may ask the Regional Supervisor to allow you more than 180 days to resume operations on a lease continued beyond its primary term when operating conditions warrant. The request must be in writing and explain the operating conditions that warrant a longer period. In allowing additional time, the Regional Supervisor must determine that the longer period is in the national interest and that it conserves resources, prevents waste, or protects correlative rights.

[61 FR 55887, Oct. 30, 1996; 62 FR 35247, June 30, 1997]

§ 250.14 Reinjection and subsurface storage of gas.

(a)(1) The Regional Supervisor may authorize the reinjection of gas on the OCS to promote conservation of natural resources and to prevent waste when it can be shown that no undue interference with operations under existing leases will result.

(2) An application for reinjection of gas may be approved for the purpose of the following:

(i) Enhanced recovery projects,

(ii) Preventing of the flaring of casinghead gas, or

(iii) Other conservation measures approved by the Regional Supervisor.

(b)(1) The Regional Supervisor may authorize subsurface storage of gas on the OCS for later commercial benefit when it can be shown that no undue interference with operations under existing leases will result.

(2) In each case authorized in paragraph (b)(1) of this section, a storage agreement will be required, and the authorization for storage will provide for the payment of a storage fee or rental.

(c) Reinjection or storage of gas may be approved for locations on- or off-lease, provided that when gas is reinjected or stored off the lease or unit from which it was produced, royalties shall be paid at the time the gas is first

produced. Gas produced from a reservoir containing both reinjected or stored gas and gas original to the reservoir shall be presumed to be made up of proportionate amounts of injected or stored gas and gas original to the reservoir in accordance with a formula approved or prescribed by the Regional Supervisor.

(d) The use of all or any part of a lease area for subsurface storage of gas shall not affect the continuance or expiration of such lease.

(e) Gas may not be stored on unleased lands unless a right of use and easement for that purpose has been approved by the Regional Supervisor in accordance with §250.7.

(f) Reinjection or storage of gas will not be approved when the gas is to be injected into the cap rock of a salt dome known to contain a sulphur deposit, unless the injection of gas is necessary to the recovery of oil and gas contained in the cap rock, and the applicant can demonstrate to the satisfaction of the Regional Supervisor that the injection of gas will not significantly increase potential hazards to present or future sulphur mining operations.

[53 FR 10690, Apr. 1, 1988 as amended at 56 FR 32099, July 15, 1991]

§250.15 Identification.

(a) Platforms, structures, artificial islands, and mobile drilling units which have helicopter landing facilities shall be identified with at least one sign using letters and figures not less than 12 inches in height. Signs for units without helicopter landing facilities shall use letters and figures not less than 3 inches in height. Signs shall be affixed at a location that is visible to approaching traffic and shall contain the following information which may be abbreviated:

(1) Name of the lease operator,

(2) The area designation based on OCS Official Protraction Diagrams (except in the Pacific OCS Region),

(3) The block number (lease number in the Pacific OCS Region) in which the facility is located, and

(4) Platform, structure, or rig name.

(b) For each singly completed well, the lease number and well number shall be painted on the wellhead or on a sign affixed to the wellhead. In wells with multiple completions, each completion shall be individually identified at the wellhead. For subsea wellheads, the required sign shall be affixed to the flowline at a convenient surface location on the platform to which it is connected. All identifying signs shall be maintained in a legible condition.

§250.16 Reimbursement.

(a) When geological data, geophysical data, analyzed geological information, processed geological and geophysical information, reprocessed geological and geophysical information, and interpreted geological and geophysical information are submitted to MMS pursuant to the requirements of this part (whether or not retained by MMS) and upon receipt of a request for reimbursement no later than 90 days from the date of delivery and a determination by the Regional Supervisor that the requested reimbursement is proper, the lessee or third party shall be reimbursed for the reasonable costs of reproducing such data and information at the lessee's or third party's lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) When processed or reprocessed geological or geophysical information is submitted to MMS pursuant to the requirements of this part (whether retained by the Regional Supervisor or not) and upon receipt of a request for reimbursement no later than 90 days from the date of delivery and a determination by the Regional Supervisor that the requested reimbursement is proper, the lessee or third party shall be reimbursed for the reasonable costs attributable to processing and reprocessing such information (as distinguished from the cost of data acquisition) but only if the processing or reprocessing was in the form and manner of processing other than that used in the normal conduct of the lessee's business and was done at the specific request of the Regional Supervisor.

(c) Requests for reimbursement shall identify processing and reprocessing costs separate from acquisition costs.

(d) The lessee shall not be reimbursed for the costs of analyzing geological information or for interpreting geological or geophysical information.

§ 250.17 Information and forms.

(a) Information required to be submitted pursuant to the regulations in this part shall be furnished in the manner and form prescribed in the regulations in this part or as ordered by the Director. Copies of forms may be obtained from the Regional or District Supervisor and shall be filled out completely and filed punctually with the Regional or District Supervisor. Computer generated forms which are equal in size, readability, and paper quality, and which arrange the data in identical format, may be submitted in lieu of the forms available from the Regional or District Supervisor.

(b) Reports submitted on forms prescribed under this part or otherwise required by the Director shall include a copy marked ''Public Information'' which shall include all required information except that exempt from public disclosure in § 250.18 or otherwise exempt from public disclosure under law or regulation.

§ 250.18 Data and information to be made available to the public.

(a) Except as provided in paragraph (c) of this section or in § 252.7 of this chapter, geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geological and geophysical information, submitted at any time pursuant to the requirements of this part, shall not be available for public inspection without the consent of the lessee as long as the lease remains in effect, or for a period of 10 years after the date of submission, whichever is less, unless the Director determines that:

(1) The data and information are needed to unitize operations on 2 or more leases, to ensure proper plans of development for competitive reservoirs, or to promote operational safety or protection of the environment, and the data and information are shown only to persons with an interest in the issue,

(2) The geological and geophysical data and information are necessary for specific scientific or research purposes for the Government and the release of such data and information would further the nation interest without unduly damaging the competitive position of the lessee.

(b) Except as provided in paragraph (c) of this section or in § 252.7 of this chapter, geological data and analyzed geological information submitted pursuant to the requirements of this part, shall not be available for public inspection without the consent of the lessee except under one of the following conditions based on the status of the lease at the time of release of the data and information:

(1) For leases no longer in effect, the data and information will be released.

(2) For a lease in effect, and within the primary term specified in the lease, the data and information may be released 2 years after submission of the data or information or 60 days after a lease sale such that any portion of an offered block is within 50 miles of a well, whichever is later. For the purpose of this paragraph 2, the primary term specified in a lease shall be deemed to be extended for a period of time equal to the period of time for which a suspension of operations is granted pursuant to § 250.10 of this part; provided that the primary term specified in a lease shall not be deemed to be extended for a suspension of operations directed in accordance with § 250.10 (b)(1) of this part.

(3) For leases in effect and beyond the primary term specified in the lease, except as provided in paragraph (b)(2) of this section, data and information will be released 2 years after submission.

(4) For all leases, the data and information may be released if the Director determines that:

(i) The data and information are needed to unitize operations on 2 or more leases, to ensure proper plans of development for competitive reservoirs, or to promote operational safety or protection of the environment, and the data and information are shown only to persons with an interest in the issue;

(ii) The geological data and information are necessary for specific scientific or research purposes for the

Government and the release of such data and information would further the national interest without unduly damaging the competitive position of the lessee.

(c) Geophysical data, geological data, processed geological and geophysical information, and interpreted geological and geophysical information collected on a lease with high-resolution systems (including, but not limited to, bathymetry, side-scan sonar, subbottom profiler, and magnetometer) in compliance with requirements concerning protection of environmental aspects of the lease may be made available to the public 60 days after submittal to the Regional Supervisor. However, unless the lessee can demonstrate to the satisfaction of the Regional Supervisor that release of the data or information would unduly damage the lessee's competitive position, the Regional Supervisor may release the data and information at an earlier time if the Regional Supervisor determines it is needed by affected States to make determinations under subpart B, Exploration and Development and Production Plans, of this part.

(d) Data and information identified on Forms MMS–123 through MMS–128 are protected as follows:

(1) On Form MMS–123, Application for Permit to Drill, the following items of data and information shall not be available for public inspection without the consent of the lessee for the same periods as those provided in paragraph (b) of this section or until the well goes on production, whichever is earlier:

(i) Item 17, Well Location at Total Depth (Estimated);

(ii) Item 24, Total Depth (Proposed), MD and TVD;

(iii) Item 25, Attachments.

(2) On Form MMS–124, Sundry Notices and Reports on Wells, Item 36, Describe Proposed or Completed Operations, shall not be available for public inspection without the consent of the lessee for the same periods as those provided in paragraph (b) of this section or until the well goes on production, whichever is earlier.

(3) On Form MMS–125, Well Summary Report, the following data and information shall not be available for public inspection without the consent of the lessee for the same periods as those provided in paragraph (b) of this section or until the well goes on production, whichever is earlier, except that Item 78, Summary of Porous Zones, and Item 85, Geologic Markers, shall not be released when the well goes on production unless the period of time specified in paragraph (b) of this section has expired.

(i) Item 17, Well Location at Total Depth (Surveyed);

(ii) Item 24, Total Depth (Surveyed), MD and TVD;

(iii) Item 34, Well Status/Type Code;

(iv) Item 37, Well Location at the Producing Zone (Surveyed);

(v) Item 46, Top (MD);

(vi) Item 47, Bottom (MD);

(vii) Item 48, Top (TVD);

(viii) Item 49, Bottom (TVD);

(ix) Item 50, Reservoir Name;

(x) Item 51, Name(s) of Producing Formation(s) This Completion;

(xi) Item 52, Hole Size;

(xii) Item 53, Casing Size;

(xiii) Item 54, Casing Weight;

(xiv) Item 55, Grade;

(xv) Item 56, Setting Depth (MD);

(xvi) Item 57, Cement Type;

(xvii) Item 58, Quantity of Cement (FT^3);

(xviii) Item 59, Hole Size;

(xix) Item 60, Tubing Size;

(xx) Item 61, Tubing Weight;

(xxi) Item 62, Grade;

(xxii) Item 63, Setting Depth (MD);

(xxiii) Item 64, Packer Setting Depth (MD);

(xxiv) Item 65, Hole Size;

(xxv) Item 66, Liner Size;

(xxvi) Item 67, Liner Wt.;

(xxvii) Item 68, Grade;

(xxviii) Item 69, Top (MD);

(xxix) Item 70, Bottom (MD);

(xxx) Item 71, Cement Type;

(xxxi) Item 72, Cement Quantity (Ft^3);

(xxxii) Item 73, Top (MD);

(xxxiii) Item 74, Bottom (MD);

(xxxiv) Item 75, Type of Material;

(xxxv) Item 76, Material Quantity;

(xxxvi) Item 77, List of Electric and Other Logs Runs, Directional Surveys, Velocity Surveys, and Core Analysis;

(xxxvii) Item 78, Summary of Porous Zones: Show all zones containing hydrocarbons; all cored intervals; and attach all drill stem and well potential tests;

(xxxviii) Item 79, Formation;
(xxxix) Item 80, Top MD;
(xl) Item 81, Top TVD;
(xli) Item 82, Bottom MD;
(xlii) Item 83, Bottom TVD;
(xliii) Item 84, Description, Contents, Etc.;
(xliv) Item 85, Geologic Markers;
(xlv) Item 86, Top MD;
(xlvi) Item 87, Top TVD.

(4) On Form MMS–126, Well Potential Test Report and Request for Maximum Production Rate (MPR), Item 101, Static Bottomhole Pressure, is not available to the public until 2 years after submittal. All other data and information on Form MMS–126 are available to the public upon commencement of production.

(5) On Form MMS–127, Request for Reservoir Maximum Efficient Rate (MER), the following data and information are not available for public inspection without the consent of the lessee for the same periods as those provided in paragraph (b) of this section:
(i) Item 124, Upper ϕ Cut Off;
(ii) Item 125, Lower ϕ Cut Off;
(iii) Item 126, Upper k Cut Off;
(iv) Item 127, Lower k Cut Off;
(v) Item 128, G/O Interface;
(vi) Item 129, W/O Interface;
(vii) Item 130, G/W Interface;
(viii) Item 131, A_g;
(ix) Item 132, A_o;
(x) Item 133, V_o;
(xi) Item 134, V_g;
(xii) Item 135, H_o;
(xiii) Item 136, h_o;
(xiv) Item 137, H_g;
(xv) Item 138, H_g;
(xvi) Item 139, ϕ_e;
(xvii) Item 140, S_w;
(xviii) Item 141, S_g;
(xix) Item 142, S_o;
(xx) Item 143, B_{oi};
(xxi) Item 144, B_{gi};
(xxii) Item 145, N;
(xxiii) Item 146, G;
(xxiv) Item 147, K_h;
(xxv) Item 148, K_v;
(xxvi) Item 149, Avg Well Depth;
(xxvii) Item 150, R_{io};
(xxviii) Item 151, R_{ig};
(xxix) Item 152, $R_{io}N$;
(xxx) Item 153, $R_{ig}G$;
(xxxi) Item 154, $N_p(2)/N$;
(xxxii) Item 155, $G_p(2)/G$;
(xxxiii) Item 156, Degrees API @ 60°F;
(xxxiv) Item 157, SG;
(xxxv) Item 158, R_{si};
(xxxvi) Item 159, μ_{oi};
(xxxvii) Item 160, μ_o;
(xxxviii) Item 161, T_{avg};
(xxxix) Item 162, P_i;
(xl) Item 163, P_iDATE;
(xli) Item 164, P_{ws};
(xlii) Item 165, P_{ws}DATE;
(xliii) Item 166; P_b;
(xliv) Item 167; P_d;
(xlv) Item 168, Datum Depth.

(6) All data and information on Form MMS–128 are available for public inspection.

(e) Directional survey data released to the owner of an adjacent lease pursuant to § 250.51(e)(5) shall not be released to the public without the consent of the lessee from whose lease the directional survey was taken.

(f) Data and information obtained from beneath unleased land as a result of a well deviation which has not been approved by the Regional Supervisor shall be available to the public.

[53 FR 10690, Apr. 1, 1988, as amended at 59 FR 12161, Mar. 16, 1994]

§ 250.19 Accident reports.

(a) The lessee shall notify the District Supervisor of all serious accidents, any death or serious injury, and all fires, explosions, and blowouts connected with any activities or operations on the lease. All spills of oil or other liquid pollutants must be reported as described in § 254.46.

(b) The owner of an easement, right-of-way, or other permit shall comply with paragraph (a) of this section by notification and report submittal to the Regional Supervisor for such incidents occurring on the area covered by the easement, right-of-way, or other permit.

(c) Unless otherwise specifically ordered by the Director, all investigations conducted under the authority of sections 22(d) (1) and (2) of the Act shall be fact-finding proceedings with no civil or criminal issues and no adverse parties. The purpose of the investigation is to prepare a public report. Such investigations shall satisfy the following requirements:

(1) Any meetings shall be conducted in the appropriate MMS regional or

district office or at some other convenient location determined by the panel chairperson. The chairperson may open a meeting or any part of it to the public if the chairperson determines that it would aid the panel in its work.

(2) All members of the panel shall be present at such meetings if possible. The chairperson may designate a member(s) of the panel to conduct meetings without all members present if the chairperson finds it to be appropriate.

(3) Appropriate oaths shall be administered by the chairperson or his/her designeee to all persons giving testimony.

(4) A verbatim transcript shall be made of any oral testimony.

(5) Each person giving testimony shall be allowed to have legal and/or other representative(s) present to advise or counsel when giving testimony to the panel.

(6) Only the following persons shall address questions to any person giving testimony:

(i) The panel members, the panel's legal advisors, any experts the panel deems necessary; and

(ii) The testimony transcriber.

(7) The chairperson of the panel may, if necessary, issue a subpoena to any witness or person who has knowledge of the accident pursuant to section 22(l) of the Act. A witness or a person who has knowledge of the accident may be required to attend a meeting at a place not more than 100 miles from the place where the subpoena is served.

(8) Any witness or person who has knowledge of the accident and is subpoenaed to testify under this subsection shall be entitled to be paid the same fees and mileage paid for similar services in the U.S. District Courts. The MMS shall pay fees and mileage for those persons that MMS has called if the persons so request.

(9) When the witness(es) or person(s) who has knowledge of the accident cannot appear to testify due to injury or who is not required to appear as provided in paragraph (c)(7) of this section, the panel may then move the meeting site to a location more convenient to the witness(es) or person(s), or the panel may accept a sworn written statement in lieu of oral testimony.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990; 62 FR 13996, Mar. 25, 1997]

§250.20 Safe and workmanlike operations.

(a) The lessee shall perform all operations in a safe and workmanlike manner and shall maintain all equipment in a safe condition for the protection of the lease and associated facilities, the health and safety of all persons, and the preservation and conservation of property and the environment.

(b) The lessee shall immediately take all necessary precautions to control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

(c) *Crane operations.* Cranes installed on fixed platforms shall be operated and maintained in accordance with the provisions of the American Petroleum Institute (API) Recommended Practice (RP) for Operation and Maintenance of Offshore Cranes (API RP 2D) to ensure the safety of facility operations. Records of inspection, testing, maintenance, and crane operator qualifications in accordance with the provisions of API RP 2D shall be kept by the lessee at the lessee's field office nearest the Outer Continental Shelf (OCS) facility for a period of 2 years.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990]

§250.21 Access to facilities.

(a) The lessee shall make available for inspection by MMS representatives, all platforms, artificial islands, and other installations located on offshore leases. For installations equipped with helicopter landing sites and refueling facilities, the lessee shall provide the use of those facilities for helicopters used by the MMS in the supervision of offshore operations.

(b) Lessee and nonlessee owners of easements, rights-of-way, or other permits shall make available at all reasonable times for inspection by MMS the area covered by the lease, easement, right-of-way, or permit, all improvements, structures, and fixtures thereon, and all records relative to the

design, construction, operation, maintenance, repairs, or investigations on or with regard to such area.

(c) The lessee shall, on request, furnish food, quarters, and transportation for MMS representatives to inspect lease facilities and operations. Upon request no later than 90 days after furnishing food, quarters, and transportation, the lessee will be reimbursed for the costs incurred for the food, quarters, and transportation provided MMS representatives as determined by the Regional Director.

§ 250.22 Best available and safest technologies (BAST).

(a) The Director shall require on all new drilling and production operations and, wherever practicable, on existing operations, the use of the BAST, which the Director determines to be economically feasible, where ever failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

(b) Conformance to the standards, codes, and practices referenced in this part will be considered to be the application of BAST. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment. If such are identified and until specific performance standards are developed by MMS and as directed by the Regional Supervisor on a case-by-case basis, the lessee shall submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale as to why one alternative technology was considered in place of another. This analysis shall include a discussion of the costs involved in the use of such technology and the incremental benefits to be gained.

§ 250.23 Report of cessation of production.

When a lease is in its extended term in § 256.37(b), a report shall be submitted to the District Supervisor when the last well on the lease ceases production. Such a report shall contain the number of the well and the date that the last well ceased production and shall be submitted within 15 days after the end of the first month in which no production occurs. A report is not required when production resumes within 15 days after the end of the first month in which no production occurs or when production ceases as a result of a suspension of production.

§ 250.24 Appeals, general.

Orders or decisions issued under the regulations in this part may be appealed in accordance with the provisions of part 290 of this title. The filing of an appeal with the Director shall not suspend the requirement for compliance with an order or decision other than the payment of a civil-penalty. This requirement for compliance shall take precedence over any stay that may be granted other than a stay granted by the Secretary.

§ 250.25 Reports and investigations of apparent violations.

Any person may report to MMS an apparent violation or failure to comply with any provision of the Act, or any provision of a lease, license, or permit issued pursuant to the Act, or any provision of any regulation or order issued under the Act. When a report of an apparent violation has been received or when an apparent violation has been detected by MMS personnel, the matter will be investigated in accordance with MMS procedures.

[56 FR 20129, May 2, 1991]

§ 250.26 Archaeological reports and surveys.

(a) If the Regional Director believes that an archaeological resource may exist in the lease area, the Regional Director will notify the lessee in writing. The lessee shall include an archaeological report in the Exploration Plan or Development and Production Plan and shall comply with the following:

(1) If the evidence suggests that an archaeological resource may be present, the lessee shall either:

(i) Locate the site of any operation so as not to affect adversely the area

where the archaeological resource may be; or

(ii) Establish to the satisfaction of the Regional Director that an archaeological resource does not exist or will not be adversely affected by operations. This shall be done by further archaeological investigation, conducted by an archaeologist and a geophysicist, using survey equipment and techniques deemed necessary by the Regional Director. A report on the investigation shall be submitted to the Regional Director for review.

(2) If the Regional Director determines that an archaeological resource is likely to be present in the lease area and may be adversely affected by operations, the Regional Director will notify the lessee immediately. The lessee shall take no action that may adversely affect the archaeological resource until the Regional Director has told the lessee how to protect it.

(b) If the lessee discovers any archaeological resource while conducting operations in the lease area, the lessee shall immediately halt operations within the area of the discovery and report the discovery to the Regional Director. If investigations determine that the resource is significant, the Regional Director will inform the lessee how to protect it.

[59 FR 53093, Oct. 21, 1994]

Subpart B—Exploration and Development and Production Plans

§ 250.30 General requirements.

All exploration, development, and production activities except for preliminary activities shall be conducted in accordance with an Exploration Plan or a Development and Production Plan approved by the Regional Supervisor. A proposed plan may apply to one or more leases held by an individual lessee or may be submitted by a group of lessees. The Regional Supervisor may authorize lessees to jointly submit environmental information for leases that are in the same planning area and have similar environmental conditions. Any reference in this part to a Development and Production Plan shall be considered to include the Development Operations Coordination Document used in the western Gulf of Mexico (GOM) (see § 250.34(d)).

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988]

§ 250.31 Preliminary activities.

Preliminary activities are geological, geophysical, and other surveys necessary to develop a comprehensive Exploration Plan or Development and Production Plan. Such preliminary activities are those which do not result in any physical penetration of the seabed of greater than 500 feet and which do not result in any significant adverse impact on the natural resources of the Outer Continental Shelf (OCS). The Regional Supervisor may require prior notification of the type, scope, and timing of any survey.

§ 250.32 Well location and spacing.

(a) The Regional Supervisor is authorized to approve well location and spacing programs necessary for exploration and development of a leased sulphur deposit or fluid hydrocarbon reservoir giving consideration to, among other factors, the location of drilling units and platforms, extent and thickness of the sulphur deposit, geological and other reservoir characteristics, number of wells that can be economically drilled, protection of correlative rights, optimum recovery of resources, minimization of risk to the environment, and prevention of any unreasonable interference with other uses of the OCS. Well location and spacing programs shall be determined independently for each leased sulphur deposit or hydrocarbon-bearing reservoir in a manner that will locate wells in the optimum position for the most effective production of sulphur and/or reservoir fluids and avoid the drilling of unnecessary wells.

(b) For wells which could intersect or drain an offset property, the Regional Supervisor may require special measures to protect the rights of the lessor and objecting offset lessees.

(c) The lessee shall drill and produce the wells the Regional Supervisor determines are necessary to protect the lessor from loss by reason of production on other properties or in lieu

thereof, with the approval of the Regional Supervisor, pay a sum determined by the Regional Supervisor as adequate to compensate the lessor for the lessee's failure to drill and produce any well. Payment of that sum shall be considered as the equivalent of production in paying quantities for the purpose of extending the lease term.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990; 56 FR 32099, July 15, 1991]

§ 250.33 Exploration Plan.

(a) The leasee shall submit for approval an Exploration Plan which includes the following:

(1) The proposed type and sequence of exploration activities to be undertaken together with a timetable for their performance from commencement to completion.

(2) A description of the type of mobile drilling unit, platform, or artificial island to be used including a discussion of the drilling program and important safety and pollution-prevention features. In the Alaska OCS Region, lessees shall include provisions for—

(i) Drilling a relief well should a blowout occur,

(ii) Loss or disablement of a drilling unit, and

(iii) Loss or damage to support craft.

(3) A table indicating the approximate location of each proposed exploratory well, including surface locations, proposed well depths, and water depth at well sites.

(b) The lessee shall submit the following supporting information to accompany the Exploration Plan:

(1) Data and information described below which the Regional Supervisor deems necessary to evaluate geologic conditions:

(i) Current structure contour maps drawn to the top of each prospective hydrocarbon accumulation showing the approximate surface and bottomhole location of each proposed well.

(ii) Full-scale interpreted, and if appropriate, migrated Common Depth Point seismic lines intersecting at or near the primary well locations.

(iii) A time versus depth chart based on the appropriate velocity analysis in the area of interpretation.

(iv) Interpreted structure sections corresponding to each seismic line submitted in paragraph (b)(1)(ii) of this section showing the location and proposed depth of each well.

(v) A generalized stratigraphic column from the surface to total depth.

(vi) A description of the geology of the prospect.

(vii) A plat showing exploration seismic coverage of the lease.

(viii) A bathymetry map showing surface locations of proposed wells.

(ix) An analysis of seafloor and subsurface geologic and manmade hazards. Unless the lessee can demonstrate to the satisfaction of the Regional Supervisor that data sufficient to determine the presence or absence of such conditions are available, the lessee shall conduct a shallow hazards survey in accordance with the Regional Supervisor's specifications. The Regional Supervisor may require the submission of a shallow hazards report and the data upon which the analysis is based.

(2) An oil-spill response plan as described in part 254 or reference to an approved Regional Response Plan.

(3) A discussion of the measures that have been or will be taken to satisfy the conditions of lease stipulations.

(4) A list of the proposed drilling fluids, including components and their chemical compositions, information on the projected amounts and rates of drilling fluid and cuttings discharges, and method of disposal.

(5) Information concerning the presence of hydrogen sulfide (H_2S) and the following proposed precautionary measures:

(i) A classification of the lease area as to whether it is within an area known to contain H_2S, an area where the presence of H_2S is unknown, or an area where the absence of H_2S has been confirmed as described in § 250.67 of this part and the documentation supporting the classification; and

(ii) If the classification is an area known to contain H_2S or an area where the presence of H_2S is unknown, an H_2S Contingency Plan as required in § 250.67 of this part.

(6) A detailed discussion of new or unusual technology to be employed. The lessee shall indicate which portions of the supporting information the

lessee believes are exempt from disclosure under the Freedom of Information Act (FOIA) (5 U.S.C. 552) and the implementing regulations (43 CFR part 2). The lessee shall include a written discussion of the general subject matter of the deleted portions for transmittal to the recipients of plan copies.

(7) A brief description of the onshore facilities to be used to support the exploration activities including information as to whether the facilities are existing, proposed, or are to be expanded; a brief description of support vessels to be used and information concerning their frequency of travel; and a map showing the lease relative to the shoreline and depicting proposed transportation routes.

(8) For onshore support facilities, except in the western GOM, indicate the following:

(i) The location, size, number, and land requirements (including rights-of-way and easements) of the onshore support and storage facilities and, where possible, a timetable for the acquisition of lands and the construction or expansion of any facilities.

(ii) The estimated number of persons expected to be employed in support of offshore, onshore, and transportation activities and, where possible, the approximate number of new employees and families likely to move into the affected area.

(iii) Major supplies, services, energy, water, or other resources within affected States necessary for carrying out the related plan.

(iv) The source, composition, frequency, and duration of emissions of air pollutants.

(9) The quantity, composition, and method of disposal of solid and liquid wastes and pollutants likely to be generated by offshore, onshore, and transportation operations.

(10) Historic weather patterns and other meteorological conditions of offshore areas including temperature, sky cover and visibility, precipitation, storm frequency and magnitude, wind direction and velocity, and freezing and icing conditions listing, where possible, the means and extremes of each.

(11) Physical oceanography including onsite direction and velocity of currents and tides, sea states, temperature, and salinity, water quality, and icing conditions, where appropriate.

(12) Onsite flora and fauna including both pelagic and benthic communities, transitory birds and mammals that may breed or migrate through the area when proposed activities are being conducted, identification of endangered and threatened species and their critical habitats that could be affected by proposed activities, and typical fishing seasons and locations of fishing activities. The results of any biological surveys required by the Regional Supervisor (including a copy of survey reports or references to previously submitted reports) should be incorporated into this discussion.

(13) Environmentally sensitive areas (onshore as well as offshore), e.g., refuges, preserves, sanctuaries, rookeries, calving grounds, and areas of particular concern identified by an affected State pursuant to the Coastal Zone Management Act (CZMA) which may be affected by the proposed activities.

(14) Onsite uses of the area based on information available, e.g., shipping, military use, recreation, boating, commercial fishing, subsistence hunting and fishing, and other mineral exploration in the area.

(15) If the Regional Director believes that an archaeological resource may exist in the lease area, the Regional Director will notify the lessee in writing. Prior to commencing any operations, the lessee shall prepare a report, as specified by the Regional Director, to determine the potential existence of any archaeological resource that may be affected by operations. The report shall be prepared by an archaeologist and geophysicist and shall be based on an assessment of data from remote-sensing surveys and of other pertinent archaeological and environmental information.

(16) Existing and planned monitoring systems that are measuring or will measure environmental conditions and provide data and information on the impacts of activities in the geographic areas.

(17) An assessment of the direct and cumulative effects on the offshore and onshore environments expected to occur as a result of implementation of the Exploration Plan, expressed in

terms of magnitude and duration, with special emphasis upon the identification and evaluation of unavoidable and irreversible impacts on the environment. Measures to minimize or mitigate impacts should be identified and discussed.

(18) Certificate(s) of coastal zone consistency as provided in 15 CFR part 930.

(19) For each OCS facility, the lessee shall submit the information described below when it is needed to make the findings under § 250.45 or § 250.46 of this part:

(i)(A) Projected emissions from each proposed or modified facility for each year of operation and the basis for all calculations to include (if the drilling unit has not yet been determined, the lessee shall use worst-case estimates for the type of unit proposed):

(*1*) For each source, the amount of the emission by air pollutant expressed in tons per year and the frequency and duration of emissions.

(*2*) For each facility, the total amount of emissions by air pollutant expressed in tons per year and, in addition for a modified facility only, the incremental amount of total emissions by air pollutant resulting from the new or modified source(s).

(*3*) A detailed description of all processes, processing equipment, and storage units, including information on fuels to be burned.

(*4*) A schematic drawing which identifies the location and elevation of each source.

(*5*) If projected emissions are based on the use of emission-reduction control technology, a description of the controls providing the information required by paragraph (b)(19)(iv) of this section.

(B) The distance of each proposed facility from the mean high water mark (mean higher high water mark on the Pacific coast) of any State.

(ii)(A) The model(s) used to determine the effect on the onshore air quality of emissions from each facility, or from other facilities when required by the Regional Supervisor, and the results obtained through the use of the model(s). Only model(s) that has been approved by the Director may be used.

(B) The best available meteorological information and data consistent with the model(s) used stating the basis for the data and information selected.

(iii) The air quality status of any onshore area where the air quality is significantly affected (within the meaning of § 250.45 of this part) by projected emissions from each facility proposed in the plan. The area should be classified as nonattainment, attainment, or unclassifiable to include the status of each area by air pollutant, the class of attainment area, and the air-pollution control agency whose jurisdiction covers the area identified.

(iv) The emission-reduction controls available to reduce emissions, including the source, the emission-reduction control technology, reductions to be achieved, and monitoring system the lessee proposes to use to measure emissions. The lessee shall indicate which emission-reduction control technology the lessee believes constitutes the best available control technology and the basis for that opinion.

(20) The name, address, and telephone number of an individual employee of the lessee to whom inquiries by the Regional Supervisor and the affected State(s) may be made.

(21) Such other information and data as the Regional Supervisor may require.

(c) Information and data discussed in other documents previously submitted to MMS or otherwise readily available to reviewers may be referenced. The material being referenced shall be cited, described briefly, and include a statement of where the material is available for inspection. Any material based on proprietary data which is not itself available for inspection shall not be so referenced.

(d) The Regional Director, after consultation with the Governor of the affected State(s) or the Governor's designated representative, the CZM agency of affected State(s), and the Office of Ocean and Coastal Resource Management of the National Oceanic and Atmospheric Administration (NOAA) may limit the amount of information required to be included to that necessary to assure conformance with the Act, other laws, applicable regulations, and lease provisions.

(e) The Regional Supervisor shall determine within 10 working days after

receipt of the Exploration Plan whether additional information is needed. If no deficiencies are identified and the required number of copies have been received, the plan will be deemed submitted.

(f) Within 2 working days after the date an Exploration Plan has been deemed submitted, the Regional Supervisor shall transmit by receipted mail a copy of the plan, except for those portions determined to be exempt from disclosure under the FOIA and the implementing regulations (43 CFR part 2), to the Governor or the Governor's designated representative and the CZM agency of each affected State. Receipt of the plan by the CZM agency initiates the State coastal zone consistency review period.

(g) In accordance with the National Environmental Policy Act (NEPA), the Regional Supervisor shall evaluate the environmental impacts of the activities described in the Exploration Plan.

(h) In the evaluation of an Exploration Plan, the Regional Supervisor shall consider written comments from the Governor of an affected State or the Governor's designated representative which are received prior to the deadline specified by the Regional Supervisor. The Regional Supervisor may consult directly with affected States regarding matters contained in the comments.

(i) Within 30 days of submission of a proposed Exploration Plan, the Regional Supervisor shall accomplish one of the following:

(1) Approve the plan;

(2) Require the lessee to modify any plan which is inconsistent with the provisions of the lease, the Act, or the regulations prescribed under the Act including air quality, environmental, safety, and health requirements; or

(3) Disapprove the plan if the Regional Supervisor determines that a proposed activity would probably cause serious harm or damage to life (including fish and other aquatic life), property, natural resources offshore including any mineral deposits (in areas leased or not leased), the national security or defense, or the marine, coastal, or human environment, and that the proposed activity cannot be modified to avoid the condition(s).

(j) The Regional Supervisor shall notify the lessee in writing of the reason(s) for disapproving an Exploration Plan or for requiring modification of a plan. For plans requiring modification, the Regional Supervisor shall also notify the lessee in writing of the conditions that must be met for plan approval.

(k)(1) The lessee may resubmit an Exploration Plan, as modified, to the Regional Supervisor in the same manner as for a new plan. Only information related to the proposed modifications need be submitted. The Regional Supervisor shall approve, disapprove, or require modification of the resubmitted plan based upon the criteria in paragraph (i) of this section within 30 days of the resubmission date.

(2) An Exploration Plan which has been disapproved pursuant to paragraph (i)(3) of this section may be resubmitted if there is a change in the conditions which caused it to be disapproved. The Regional Supervisor shall approve, require modification, or disapprove such a plan within 30 days of the resubmission date.

(l) When a State objects to a lessee's coastal zone consistency certification, the lessee shall modify the plan to accommodate the State's objection(s) and resubmit the plan to—

(1) The Regional Supervisor for review pursuant to the criteria in paragraphs (h), (i), and (j) of this section; and

(2) Through the Regional Supervisor to the State for review pursuant to the CZMA and the implementing regulations (15 CFR 930.83 and 930.84).

Alternatively, the lessee may appeal the State's objection to the Secretary of Commerce pursuant to the procedures described in section 307 of the CZMA and the implementing regulations (subpart H of 15 CFR part 930). The Regional Supervisor shall approve or disapprove a plan as resubmitted within 30 days of the resubmission date.

(m) If the Regional Supervisor disapproves an Exploration Plan, the Secretary may, subject to the provisions of section 5(a)(2)(B) of the Act and the implementing regulations in § 250.12 and 256.77 of this chapter II, cancel the lease(s), and the lessee shall be entitled

to compensation in accordance with section 5(a)(2)(c) of the Act.

(n)(1) The Regional Supervisor shall periodically review the activities being conducted under an approved Exploration Plan and may request updated information on schedules and procedures. The frequency and extent of the Regional Supervisor's review shall be based upon the significance of any changes in available information and in other onshore or offshore conditions affecting or affected by exploration activities being conducted pursuant to the plan. If the review indicates that the plan should be revised to meet the requirements of this part, the Regional Supervisor shall require the needed revision.

(2) Revisions to an approved or pending Exploration Plan, whether initiated by the lessee or ordered by the Regional Supervisor, shall be submitted to the Regional Supervisor for approval. Only information related to the proposed revisions need be submitted. When the Regional Supervisor determines that a proposed revision could result in a significant change in the impacts previously identified and evaluated or requires additional permits, the revisions shall be subject to all of the procedures in this section.

(o) To ensure safety and protection of the environment and archaeological resources, the Regional Director may authorize or direct the lessee to conduct geological, geophysical, biological, archaeological, or other surveys or monitoring programs. The lessee shall provide the Regional Director, upon request, with copies of any data obtained as a result of those surveys and monitoring programs.

(p) The lessee may not drill any well until the District Supervisor's approval of an Application for Permit to Drill (APD), submitted in accordance with the requirements of § 250.64 of this part, has been received. The District Supervisor shall not approve any APD until all affected States with approved CZM programs have concurred or have been conclusively presumed to concur with the applicant's coastal zone consistency certification accompanying a plan, or the Secretary of Commerce has made the finding authorized by section 307(c)(3)(B)(iii) of the CZMA. The APD's must conform to the activities described in detail in the approved Exploration Plan and shall not be subject to a separate State coastal zone consistency review.

(q) Nothing in this section or in an approved plan shall limit the lessee's responsibility to take appropriate measures to meet emergency situations. In such situations, the Regional Supervisor may approve or require departures from an approved Exploration Plan.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 59 FR 53093, Oct. 21, 1994; 62 FR 13996, Mar. 25, 1997]

§ 250.34 Development and Production Plan.

(a) The lessee shall submit for approval a Development and Production Plan which includes the following:

(1) A description of and schedule for the development and production activities to be performed including plan commencement date, date of first production, total time to complete all development and production activities, and dates and sequences for drilling wells and installing facilities and equipment.

(2) A description of any drilling vessels, platforms, pipelines, or other facilities and operations located offshore which are proposed or known by the lessee (whether or not owned or operated by the lessee) to be directly related to the proposed development, including the location, size, design, and important safety, pollution prevention, and environmental monitoring features of the facilities and operations.

(b) The lessee shall submit the following supporting information to accompany the Development and Production Plan:

(1) Geological and geophysical (G&G) data and information, including the following:

(i) A plat showing the surface location of any proposed fixed structure or well.

(ii) A plat showing the surface and bottomhole locations and giving the measured and true vertical depths for each proposed well.

(iii) Current interpretations of relevant G&G data.

(iv) Current structure map(s) showing the surface and bottomhole location of each proposed well and the depths of expected productive formations.

(v) Interpreted structure sections showing the depths of expected productive formations.

(vi) A bathymetric map showing surface locations of fixed structures and wells or a table of water depths at each proposed site.

(vii) A discussion of seafloor conditions including a shallow hazards analysis for proposed drilling and platform sites and pipeline routes. This information shall be derived from the shallow hazards report required by § 250.139 of this part.

(2) Information concerning the presence of H_2S and proposed precautionary measures, including the following:

(i) A classification of the lease area as to whether it is within an area known to contain H_2S, an area where the presence of H_2S is unknown, or an area where the absence of H_2S has been confirmed as described in § 250.67 of this part and the documentation supporting the classification; or

(ii) If the classification is an area known to contain H_2S or an area where the presence of H_2S is unknown, an H_2S Contingency Plan as required in § 250.67 of this part.

(3) A description of the environmental safeguards to be implemented, including an updated oil-spill response plan as described in part 254 of this chapter or reference to an approved plan.

(4) A discussion of the steps that have been or will be taken to satisfy the conditions of lease stipulations.

(5)(i) A description of technology and reservoir engineering practices intended to increase the ultimate recovery of oil and gas, i.e., secondary, tertiary, or other enhanced recovery practices;

(ii) A description of technology and recovery practices and procedures intended to assure optimum recovery of sulphur; or

(iii) A description of technology and recovery practices and procedures intended to assure optimum recovery of oil and gas and sulphur.

(6) A discussion of the proposed drilling and completion programs.

(7) A detailed description of new or unusual technology to be employed. The lessee shall indicate which portions of the information the lessee believes are exempt from disclosure under the FOIA (5 U.S.C. 552) and the implementing regulations (43 CFR part 2). The lessee shall include a written discussion of the general subject matter of the deleted portions for transmittal to recipients of plan copies.

(8) A brief description of the following:

(i) The location, description, and size of any offshore, and to the maximum extent practicable, land-based operations to be conducted or contracted for as a result of the proposed activity, including the following:

(A) The acreage required within a State for facilities, rights-of-way, and easements.

(B) The means proposed for transportation of oil, gas, and sulphur to shore; the routes to be followed by each mode of transportation; and the estimated quantities of oil, gas, and sulphur to be moved along such routes.

(C) An estimate of the frequency of boat and aircraft departures and arrivals, the onshore location of terminals, and the normal routes for each mode of transportation.

(ii) A list of the proposed drilling fluids including components and their chemical compositions, information on the projected amounts and rates of drilling fluid and cuttings discharges, and method of disposal. If the information is provided in an approved Environmental Protection Agency, National Pollutant Discharge Elimination System permit, or a pending permit application, the lessee may reference these documents.

(iii) The quantities, types, and plans for disposal of other solid and liquid wastes and pollutants likely to be generated by offshore, onshore, and transport operations and, regarding any wastes which may require onshore disposal, the means of transportation to be used to bring the wastes to shore, disposal methods to be utilized, and location of onshore waste disposal or treatment facilities.

(iv) The following information on onshore support facilities, except in the western GOM:

(A) The approximate number, timing, and duration of employment of persons who will be engaged in onshore development and production activities, an approximate number of local personnel who will be employed for or in support of the development activities (classified by the major skills or crafts that will be required from local sources and estimated number of each such skill needed), and the approximate total number of persons who will be employed during the onshore construction activity and during all activities related to offshore development and production.

(B) The approximate number of people and families to be added to the population of local nearshore areas as a result of the planned development.

(C) An estimate of significant quantities of energy and resources to be used or consumed including electricity, water, oil and gas, diesel fuel, aggregate, or other supplies which may be purchased within an affected State.

(D) The types of contractors or vendors which will be needed, although not specifically identified, and which may place a demand on local goods and services.

(E) The source, composition, frequency, and duration of emissions of air pollutants.

(v) A narrative description of the existing environment with an emphasis placed on those environmental values that may be affected by the proposed action. This section shall contain a description of the physical environment of the area covered by the related plan. This portion of the plan shall include data and information obtained or developed by the lessee together with other pertinent information and data available to the lessee from other sources. The environmental information and data shall include the following, where appropriate:

(A) If the Regional Director believes that an archaeological resource may exist in the lease area, the Regional Director will notify the lessee in writing. Prior to commencing any operations, the lessee shall prepare a report, as specified by the Regional Director, to determine the potential existence of any archaeological resource that may be affected by operations. The report shall be prepared by an archaeologist and geophysicist and shall be based on an assessment of data from remote-sensing surveys and of other pertinent archaeological and environmental information.

(B) The aquatic biota, including a description of fishery and marine mammal use of the lease and the significance of the lease, and a description of any threatened and endangered species and their critical habitat. The results of any biological surveys required by the Regional Supervisor (including a copy of survey reports or references to previously submitted reports) should be incorporated into these discussions.

(C) Environmentally sensitive areas (e.g., refuges, preserves, sanctuaries, rookeries, calving grounds, coastal habitat, beaches, and areas of particular environmental concern) which may be affected by the proposed activities.

(D) The predevelopment, ambient water-column quality and temperature data for incremental depths for the areas encompassed by the plan.

(E) The physical oceanography, including ocean currents described as to prevailing direction, seasonal variations, and variations at different water depths in the lease.

(F) Historic weather patterns and other meteorological conditions, including storm frequency and magnitude, wave height and direction, wind direction and velocity, air temperature, visibility, freezing and icing conditions, and ambient air quality listing, where possible, the means and extremes of each.

(G) The other uses of the area known to the lessee, including military use for national security or defense, subsistence hunting and fishing, commercial fishing, recreation, shipping, and other mineral exploration or development.

(H) The existing or planned monitoring systems that are measuring or will measure impacts of activities on the environment in the planning area.

(9) For sulphur operations, the degree of subsidence that is expected at various stages of production, and measures that will be taken to assure safety

of operations and protection of the environment. Special attention shall be given to the effects of subsidence on existing or potential oil and gas production, fixed bottom-founded structures, and pipelines.

(10) For sulphur operations, a discussion of the potential toxic or thermal effects on the environment caused by the discharge of bleedwater, including a description of the measures that will be taken into account to mitigate these impacts.

(11) An assessment of the effects on the environment expected to occur as a result of implementation of the plan, identifying specific and cumulative impacts that may occur both onshore and offshore, and the measures proposed to mitigate these impacts. Such impacts shall be quantified to the fullest extent possible including magnitude and duration and shall be accumulated for all activities for each of the major elements of the environment (e.g., water or biota).

(12) A discussion of alternatives to the activities proposed that were considered during the development of the plan including a comparison of the environmental effects.

(13) Certificate(s) of coastal zone consistency as provided in 15 CFR part 930.

(14) For each OCS facility, such information described below needed to make the findings under § 250.45 or § 250.46 of this part:

(i)(A) Projected emissions from each proposed or modified facility for each year of operation and basis for all calculations to include the following:

(*1*) For each source, the amount of the emission by air pollutant expressed in tons per year and frequency and duration of emissions;

(*2*) For each proposed facility, the total amount of emissions by air pollutant expressed in tons per year, the frequency distribution of total emissions by air pollutant expressed in pounds per day and, in addition for a modified facility only, the incremental amount of total emissions by air pollutant resulting from the new or modified source(s);

(*3*) A detailed description of all processes, processing equipment, and storage units, including information on fuels to be burned;

(*4*) A schematic drawing which identifies the location and elevation of each source; and

(*5*) If projected emissions are based on the use of emission-reduction control technology, a description of the controls providing the information required by paragraph (b)(12)(iv)(A) of this section.

(B) The distance of each proposed facility from the mean high water mark (mean higher high water mark on the Pacific coast) of any State.

(ii)(A) The model(s) used to determine the effect on the onshore air quality of emissions from each facility, or from other facilities when required by the Regional Supervisor, and the result obtained through the use of the model(s). Only model(s) that has been approved by the Director may be used.

(B) The best available meteorological information and data consistent with the model(s) used stating the basis for the information and data selected.

(iii) The air quality status of any onshore area where the air quality is significantly affected (within the meaning of § 250.45 of this part) by projected emissions from each facility proposed in the plan. The area should be classified as nonattainment, attainment, or unclassifiable listing the status of each area by air pollutant, the class of attainment areas, and the air pollution control agency whose jurisdiction covers the area identified.

(iv)(A) The emission-reduction controls available to reduce emissions including the source, emission-reduction control technology, reductions to be achieved, and monitoring system the lessee proposes to use to measure emissions. The lessee shall indicate which emission-reduction control technology the lessee believes constitutes the best available control technology and the basis for that opinion.

(B) The ownership of the offshore and onshore offsetting source(s) and the reduction obtainable from each offsetting source.

(15) A brief discussion of any approved or anticipated suspensions of production necessary to hold the lease(s) in an active status.

(16) The name, address, and telephone number of an individual employee of

the lessee to whom inquiries by the Regional Supervisor and the affected State(s) may be directed.

(17) Such other data and information as the Regional Supervisor may require.

(c) Data and information discussed in other documents previously submitted to MMS or otherwise readily available to reviewers may be incorporated by reference. The material being incorporated shall be cited and described briefly and include a statement of where the material is available for inspection. Any material based on proprietary data which is not itself available for inspection shall not be incorporated by reference.

(d)(1) Development and Production Plans are not required for leases in the western GOM. For these leases, the lessee shall submit to the Regional Supervisor for approval a Development Operations Coordination Document with all information necessary to assure conformance with the Act, other laws, applicable regulations, lease provisions, or as otherwise needed to carry out the functions and responsibilities of the Regional Supervisor.

(2) Any information required in paragraph (d)(1) of this section shall be considered a Development and Production Plan for the purpose of references in any law, regulation, lease provision, agreement, or other document referring to the preparation or submission of a plan.

(e) The Regional Director, after consultation with the Governor(s) of the affected State(s) or the Governor's designated representative, the CZM agency of the affected State(s), and the Office of Ocean and Coastal Resource Management of NOAA may limit the amount of information required to be included in a Development and Production Plan to that necessary to assure conformance with the Act, other laws, applicable regulations, and lease provisions. In determining the information to be included in a plan, the Regional Director shall consider current and expected operating conditions together with experience gained during past operations of a similar nature in the area of proposed activities.

(f) The Regional Supervisor shall determine within 20 working days after receipt whether additional material is needed. If no deficiencies are identified and the requested number of copies have been received, the plan shall be deemed submitted.

(g) Within 5 working days after a Development and Production Plan has been deemed submitted, the Regional Supervisor shall transmit a copy of the plan, except for those portions of the plan determined to be exempt from disclosure under the FOIA and the implementing regulations (43 CFR part 2), to the Governor or the Governor's designated representative and the CZM agency of each affected State and to the executive of each affected local government that requests a copy. The Regional Supervisor shall make copies available to appropriate Federal Agencies, interstate entities, and the public. The plan will be available for review at the appropriate MMS Regional Public Information Office.

(h) The Governor or the Governor's designated representative and the CZM agency of each affected State and the executive of each affected local government shall have 60 days from the date of receipt of the Development and Production Plan to submit comments and recommendations to the Regional Supervisor. The executive of any affected local government must forward all recommendations to the Governor of the State prior to submitting them to the Regional Supervisor. The Regional Supervisor shall accept those recommendations from the Governor that provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State. The Regional Supervisor shall explain in writing the reasons for accepting or rejecting any recommendations. In addition, any interested Federal Agency or person may submit comments and recommendations to the Regional Supervisor. All comments and recommendations shall be made available to the public.

(i) The plan will be processed in accordance with the regulations in this section and the regulations governing Federal CZM consistency procedures (15 CFR part 930).

(j) The Regional Supervisor shall evaluate the environmental impact of

the activities described in the Development and Production Plan and prepare the appropriate environmental documentation in accordance with NEPA. At least once in each planning area, as identified by the Director, other than the western and central GOM planning areas, the Director shall determine that an Environmental Impact Statement (EIS) is required. A determination by the Director that approval of a Development and Production Plan requires proceedings under NEPA shall have no effect upon the timeframe that a State has to complete its coastal zone consistency review. Copies of the draft EIS shall be transmitted to the Governor of each affected State and the executive of each affected local government that requests a copy. The Regional Supervisor shall also make copies of the draft EIS available to any appropriate Federal Agency, interstate entity, and the public.

(k) Prior to or immediately after a determination by the Director that approval of a Development and Production Plan requires that the procedures under NEPA shall commence, the Regional Supervisor may require lessees of tracts in the vicinity, for which Development and Production Plans have not been approved, to submit preliminary or final plans for their leases.

(l) No later than 60 days after the last day of the comment period provided in paragraph (h) of this section or within 60 days of the release of the final EIS describing the proposed activities, the Regional Supervisor shall accomplish the following:

(1) Approve the plan;

(2) Require modification of the plan if it is determined that the lessee has failed to make adequate provisions for safety, environmental protection, or conservation of resources including compliance with the regulations prescribed under the Act; or

(3) Disapprove the plan if one or more of the following occurs:

(i) The lessee fails to demonstrate that compliance with the requirements of the Act, provisions of the regulations prescribed under the Act, or other applicable Federal laws is possible;

(ii) State concurrence with the applicant's coastal zone consistency certification has not been received, the State's concurrence has not been conclusively presumed, or the State objects to the consistency certification, and the Secretary of Commerce does not make the determination authorized by section 307(c)(3)(B)(iii) of the CZMA;

(iii) Operations threaten national security or defense; or

(iv) Exceptional geological conditions in the lease area, exceptional resource value in the marine or coastal environment, or other exceptional circumstances exist, and all of the following:

(A) Implementation of the plan would probably cause serious harm or damage to life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), the national security or defense, or to the marine, coastal, or human environments.

(B) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time.

(C) The advantages of disapproving the plan outweigh the advantages of development and production.

(m) The Regional Supervisor shall notify the lessee in writing of the reason(s) for disapproving a Development and Production Plan or for requiring modification of a plan and the conditions which must be met for plan approval.

(n) The lessee may resubmit a Development and Production Plan, as modified, to the Regional Supervisor. Only information related to the proposed modifications need be submitted. Within 60 days following the 60-day comment period provided for in paragraph (h) of this section, the Regional Supervisor shall approve, disapprove, or require modification of the modified plan.

(o)(1) If a Development and Production Plan is disapproved for the sole reason that a State consistency certification has not been obtained, the Regional Supervisor shall approve the plan upon receipt of the concurrence, at the time when concurrence is conclusively presumed, or when the Secretary of Commerce makes a finding authorized by section 307(c)(3)(B)(iii) of the CZMA.

(2) If a Development and Production Plan is disapproved because a State objects to the lessee's coastal zone consistency certification, the lessee shall modify the plan to accommodate the State's objection(s) and resubmit the plan to (i) the Regional Supervisor for review pursuant to the criteria in paragraph (l) of this section; and (ii) through the Regional Supervisor, to the State for review pursuant to the CZMA and the implementing regulations (15 CFR 930.83 and 930.84). Alternatively, the lessee may appeal the State's objection to the Secretary of Commerce pursuant to the procedures described in section 307 of the CZMA and the implementing regulations (subpart H of 15 CFR part 930). The Regional Supervisor shall approve, disapprove, or require modification of a plan as revised within 60 days following the 60-day comment period provided for in paragraph (h) of this section.

(p) Development and Production Plans disapproved pursuant to paragraph (l)(3) of this section are subject to the provisions of section 25(h)(2) of the Act and the implementing regulations in §§ 250.12 and 256.77 of this chapter.

(q)(1) The Regional Supervisor shall periodically review the activities being conducted under an approved Development and Production Plan. The frequency and extent of the Regional Supervisor's review shall be based upon the significance of any changes in available information and onshore or offshore conditions affecting or impacted by development or production activities being conducted pursuant to the plan. If the review indicates that the plan should be revised to meet the requirements of this part, the Regional Supervisor shall require the needed revisions.

(2) Revisions to an approved or pending Development and Production Plan, whether initiated by the lessee or ordered by the Regional Supervisor, shall be submitted to the Regional Supervisor for approval. Only information related to the proposed revisions need be submitted. When the Regional Supervisor determines that a proposed revision could result in a significant change in the impacts previously identified and evaluated, requires additional permits, or proposes activities not previously identified and evaluated, the revision shall be subject to all of the procedures in this section.

(3) When any revision to an approved Development and Production Plan is proposed by the lessee, the Regional Supervisor may approve the revision if it is determined that the revision is consistent with the protection of the marine, coastal, and human environments and will lead to greater recovery of oil and natural gas; will improve the efficiency, safety, and environmental protection of the recovery operation; is the only means available to avoid substantial economic hardship to the lessee; or is otherwise not inconsistent with the provisions of the Act.

(r) Whenever the lessee fails to submit a Development and Production Plan in accordance with provisions of this section or fails to comply with an approved plan, the lease may be cancelled in accordance with sections 5 (c) and (d) of the Act and the implementing regulations in §§ 250.12 and 256.77 of this chapter.

(s) To ensure safety and protection of the environment and archaeological resources, the Regional Director may authorize or direct the lessee to conduct geological, geophysical, biological, archaeological, or other surveys or monitoring programs. The lessee shall provide the Regional Director, upon request, copies of any data obtained as a result of those surveys and monitoring programs.

(t) The lessee may not drill any well until the District Supervisor's approval of an APD, filed in accordance with the requirements of § 250.64 of this part, has been received. All APD's and applications to install platforms and structures, pipelines, and production equipment must conform to the activities described in detail in the approved Development and Production Plan and shall not be subject to a separate State coastal zone consistency review.

(u) Nothing in this section or approved plans shall limit the lessee's responsibility to take appropriate measures to meet emergency situations. In

such situations, the Regional Supervisor may approve or require departures from an approved Development and Production Plan.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 55 FR 47752, Nov. 15, 1990; 56 FR 32099, July 15, 1991; 59 FR 53093, Oct. 21, 1994; 62 FR 13996, Mar. 25, 1997]

Subpart C—Pollution Prevention and Control

§ 250.40 Pollution prevention.

(a) During the exploration, development, production, and transportation of oil and gas or sulphur, the lessee shall take measures to prevent unauthorized discharge of pollutants into the offshore waters. The lessee shall not create conditions that will pose unreasonable risk to public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.

(1) When pollution occurs as a result of operations conducted by or on behalf of the lessee and the pollution damages or threatens to damage life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment, the control and removal of the pollution to the satisfaction of the District Supervisor shall be at the expense of the lessee. Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action shall be subject to modification when directed by the District Supervisor.

(2) If the lessee fails to control and remove the pollution, the Director, in cooperation with other appropriate Agencies of Federal, State, and local governments, or in cooperation with the lessee, or both, shall have the right to control and remove the pollution at the lessee's expense. Such action shall not relieve the lessee of any responsibility provided for by law.

(b)(1) The District Supervisor may restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. The District Supervisor may also restrict the use of components which could cause unreasonable degradation to the marine environment. No petroleum-based substances, including diesel fuel, may be added to the drilling mud system without prior approval of the District Supervisor.

(2) Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Supervisor.

(3) All hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed, installed, and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of offshore waters shall be undertaken immediately.

(4) Curbs, gutters, drip pans, and drains shall be installed in deck areas in a manner necessary to collect all contaminants not authorized for discharge. Oil drainage shall be piped to a properly designed, operated, and maintained sump system which will automatically maintain the oil at a level sufficient to prevent discharge of oil into offshore waters. All gravity drains shall be equipped with a water trap or other means to prevent gas in the sump system from escaping through the drains. Sump piles shall not be used as processing devices to treat or skim liquids but may be used to collect treated-produced water, treated-produced sand, or liquids from drip pans and deck drains and as a final trap for hydrocarbon liquids in the event of equipment upsets. Improperly designed, operated, or maintained sump piles which do not prevent the discharge of oil into offshore waters shall be replaced or repaired.

(5) On artificial islands, all vessels containing hydrocarbons shall be placed inside an impervious berm or otherwise protected to contain spills. Drainage shall be directed away from the drilling rig to a sump. Drains and sumps shall be constructed to prevent seepage.

(6) Disposal of equipment, cables, chains, containers, or other materials into offshore waters is prohibited.

(c) Materials, equipment, tools, containers, and other items used in the Outer Continental Shelf (OCS) which are of such shape or configuration that they are likely to snag or damage fishing devices shall be handled and marked as follows:

(1) All loose material, small tools, and other small objects shall be kept in a suitable storage area or a marked container when not in use and in a marked container before transport over offshore waters;

(2) All cable, chain, or wire segments shall be recovered after use and securely stored until suitable disposal is accomplished;

(3) Skid-mounted equipment, portable containers, spools or reels, and drums shall be marked with the owner's name prior to use or transport over offshore waters; and

(4) All markings must clearly identify the owner and must be durable enough to resist the effects of the environmental conditions to which they may be exposed.

(d) Any of the items described in paragraph (c) of this section that are lost overboard shall be recorded on the facility's daily operations report, as appropriate, and reported to the District Supervisor.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 32099, July 15, 1991]

§ 250.41 Inspection of facilities..

(a) Drilling and production facilities shall be inspected daily or at intervals approved or prescribed by the District Supervisor to determine if pollution is occurring. Necessary maintenance or repairs shall be made immediately. Records of such inspections and repairs shall be maintained at the facility or at a nearby manned facility for 2 years.

[53 FR 10690, Apr. 1, 1988, as amended at 62 FR 13996, Mar. 25, 1997]

§ 250.44 Definitions concerning air quality.

For purposes of §§ 250.45 and 250.46 of this part:

Air pollutant means any combination of agents for which the Environmental Protection Agency (EPA) has established, pursuant to section 109 of the Clean Air Act, national primary or secondary ambient air quality standards.

Attainment area means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) not to exceed any primary or secondary ambient air quality standards established by EPA.

Best available control technology (BACT) means an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account energy, environmental and economic impacts, and other costs. The BACT shall be verified on a case-by-case basis by the Regional Supervisor and may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

Emission offsets means emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan or Development and Production Plan.

Existing facility is an OCS facility described in an Exploration Plan or a Development and Production Plan submitted or approved prior to June 2, 1980.

Facility means any installation or device permanently or temporarily attached to the seabed which is used for exploration, development, and production activities for oil, gas, or sulphur and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be considered to be a single facility if the installations or devices are directly related to the production of oil, gas, or sulphur at a single site. Any vessel used to transfer production from an offshore facility shall be considered part of the facility while physically attached to it.

Nonattainment area means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) to exceed any primary or secondary ambient air quality standard established by EPA.

Projected emissions means emissions, either controlled or uncontrolled, from a source(s).

Source means an emission point. Several sources may be included within a single facility.

Temporary facility means activities associated with the construction of platforms offshore or with facilities related to exploration for or development of offshore oil and gas resources which are conducted in one location for less than 3 years.

Volatile organic compound (VOC) means any organic compound which is emitted to the atmosphere as a vapor. The unreactive compounds are exempt from the above definition.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 32100, July 15, 1991]

§ 250.45 Facilities described in a new or revised Exploration Plan or Development and Production Plan.

(a) *New plans.* All Exploration Plans and Development and Production Plans shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section, and the lessee shall comply with the requirements of this section as necessary.

(b) *Applicability of § 250.45 to existing facilities.* (1) The Regional Supervisor may review any Exploration Plan or Development and Production Plan to determine whether any facility described in the plan should be subject to review under this section and has the potential to significantly affect the air quality of an onshore area. To make these decisions, the Regional Supervisor shall consider the distance of the facility from shore, the size of the facility, the number of sources planned for the facility and their operational status, and the air quality status of the onshore area.

(2) For a facility identified by the Regional Supervisor in paragraph (b)(1) of this section, the Regional Supervisor shall require the lessee to refer to the information required in § 250.33(b)(19) or § 250.34(b)(12) of this part and to submit only that information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall submit this information within 120 days of the Regional Supervisor's determination or within a longer period of time at the discretion of the Regional Supervisor. The lessee shall comply with the requirements of this section as necessary.

(c) *Revised facilities.* All revised Exploration Plans and Development and Production Plans shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall comply with the requirements of this section as necessary.

(d) *Exemption formulas.* To determine whether a facility described in a new, modified, or revised Exploration Plan or Development and Production Plan is exempt from further air quality review, the lessee shall use the highest annual-total amount of emissions from the facility for each air pollutant calculated in § 250.33(b)(19)(i)(A) or § 250.34(b)(12)(i)(A) of this part and compare these emissions to the emission exemption amount ''E'' for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for carbon monoxide (CO); and $E=33.3D$ for total suspended particulates (TSP), sulphur dioxide (SO_2), nitrogen oxides (NO_x), and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the proposed facility from the closest onshore area of a State expressed in statute miles). If the amount of these projected emissions is less than or equal to the emission exemption amount ''E'' for the air pollutant, the facility is exempt from further air quality review required under paragraphs (e) through (i) of this section.

(e) *Significance levels.* For a facility not exempt under paragraph (d) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether the projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS: AIR POLLUTANT CONCENTRATIONS ($\mu g/m^3$)

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	.....	25	.....
TSP	1	5	.....	....	.....
NO_2	1	....	.....	....	.....
CO	.....	....	500	....	2,000

(f) *Significance determinations.* (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance level determined under paragraph (e) of this section for that air pollutant, shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (d) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(g) *Controls required.* (1) The projected emissions of any air pollutant other than VOC from any facility, except a temporary facility, which significantly affect the quality of a nonattainment area, shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(2) The projected emissions of any air pollutant other than VOC from any facility which significantly affect the air quality of an attainment or unclassifiable area shall be reduced through the application of BACT.

(i) Except for temporary facilities, the lessee also shall use an approved air quality model to determine whether the emissions of TSP or SO_2 that remain after the application of BACT cause the following maximum allowable increases over the baseline concentrations established in 40 CFR 52.21 to be exceeded in the attainment or unclassifiable area:

MAXIMUM ALLOWABLE CONCENTRATION INCREASES (μG/M³)

Air pollutant	Averaging times		
	Annual mean [1]	24-hour maximum	3-hour maximum
Class I:			
TSP	5	10	.....
SO_2	2	5	25
Class II:			
TSP	19	37	.....
SO_2	20	91	512
Class III:			
TSP	37	75	.....

MAXIMUM ALLOWABLE CONCENTRATION INCREASES (μG/M³)—Continued

Air pollutant	Averaging times		
	Annual mean [1]	24-hour maximum	3-hour maximum
SO_2	40	182	700

[1] For TSP—geometric; For SO_2—arithmetric.

No concentration of an air pollutant shall exceed the concentration permitted under the national secondary ambient air quality standard or the concentration permitted under the national primary air quality standard, whichever concentration is lowest for the air pollutant for the period of exposure. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one onshore location.

(ii) If the maximum allowable increases are exceeded, the lessee shall apply whatever additional emission controls are necessary to reduce or offset the remaining emissions of TSP or SO_2 so that concentrations in the onshore ambient air of an attainment or unclassifiable area do not exceed the maximum allowable increases.

(3)(i) The projected emissions of VOC from any facility, except a temporary facility, which significantly affect the onshore air quality of a nonattainment area shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(ii) The projected emissions of VOC from any facility which significantly affect the onshore air quality of an attainment area shall be reduced through the application of BACT.

(4)(i) If projected emissions from a facility significantly affect the onshore air quality of both a nonattainment and an attainment or unclassifiable area, the regulatory requirements applicable to projected emissions significantly affecting a nonattainment area shall apply.

(ii) If projected emissions from a facility significantly affect the onshore air quality of more than one class of

attainment area, the lessee must reduce projected emissions to meet the maximum allowable increases specified for each class in paragraph (g)(2)(i) of this section.

(h) *Controls required on temporary facilities.* The lessee shall apply BACT to reduce projected emissions of any air pollutant from a temporary facility which significantly affect the air quality of an onshore area of a State.

(i) *Emission offsets.* When emission offsets are to be obtained, the lessee must demonstrate that the offsets are equivalent in nature and quantity to the projected emissions that must be reduced after the application of BACT; a binding commitment exists between the lessee and the owner or owners of the source or sources; the appropriate air quality control jurisdiction has been notified of the need to revise the State Implementation Plan to include the information regarding the offsets; and the required offsets come from sources which affect the air quality of the area significantly affected by the lessee's offshore operations.

(j) *Review of facilities with emissions below the exemption amount.* If, during the review of a new, modified, or revised Exploration Plan or Development and Production Plan, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether emission control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(k) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional Supervisor, emissions from the facility. The lessee shall submit this information monthly in a manner and form approved or prescribed by the Regional Supervisor.

(l) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

[53 FR 10690, Apr. 1, 1988; 53 FR 19856, May 31, 1988; 53 FR 26067, July 11, 1988]

§ 250.46 Existing facilities.

(a) *Process leading to review of an existing facility.* (1) An affected State may request that the Regional Supervisor supply basic emission data from existing facilities when such data are needed for the updating of the State's emission inventory. In submitting the request, the State must demonstrate that similar offshore and onshore facilities in areas under the State's jurisdiction are also included in the emission inventory.

(2) The Regional Supervisor may require lessees of existing facilities to submit basic emission data to a State submitting a request under paragraph (a)(1) of this section.

(3) The State submitting a request under paragraph (a)(1) of this section may submit information from its emission inventory which indicates that emissions from existing facilities may be significantly affecting the air quality of the onshore area of the State. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the facility is not significantly affecting the air quality of the State.

(4) The Regional Supervisor shall evaluate the information submitted under paragraph (a)(3) of this section and shall determine, based on the basic emission data, available meteorological data, and the distance of the facility or facilities from the onshore area, whether any existing facility has the potential to significantly affect the air quality of the onshore area of the State.

(5) If the Regional Supervisor determines that no existing facility has the potential to significantly affect the air quality of the onshore area of the State

submitting information under paragraph (a)(3) of this section, the Regional Supervisor shall notify the State of and explain the reasons for this finding.

(6) If the Regional Supervisor determines that an existing facility has the potential to significantly affect the air quality of an onshore area of the State submitting information under paragraph (a)(3) of this section, the Regional Supervisor shall require the lessee to refer to the information requirements under § 250.33(b)(19) or 250.34(b)(12) of this part and submit only that information required to make the necessary findings under paragraphs (b) through (e) of this section. The lessee shall submit this information within 120 days of the Regional Supervisor's determination or within a longer period of time at the discretion of the Regional Supervisor. The lessee shall comply with the requirements of this section as necessary.

(b) *Exemption formulas.* To determine whether an existing facility is exempt from further air quality review, the lessee shall use the highest annual total amount of emissions from the facility for each air pollutant calculated in § 250.33(b)(19)(i)(A) or 250.34(b)(12)(i)(A) of this part and compare these emissions to the emission exemption amount ''E'' for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for CO; and $E=33.3D$ for TSP, SO_2, NO_X, and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the facility from the closest onshore area of the State expressed in statute miles). If the amount of projected emissions is less than or equal to the emission exemption amount ''E'' for the air pollutant, the facility is exempt for that air pollutant from further air quality review required under paragraphs (c) through (e) of this section.

(c) *Significance levels.* For a facility not exempt under paragraph (b) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS: AIR POLLUTANT CONCENTRATIONS ($\mu G/M^3$)

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	.....	25	.....
TSP	1	5	.....	....	.....
NO_2	1	....	.....	....	.....
CO	.....	....	500	....	2,000

(d) *Significance determinations.* (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance levels determined under paragraph (c) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (b) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(e) *Controls required.* (1) The projected emissions of any air pollutant which significantly affect the air quality of an onshore area shall be reduced through the application of BACT.

(2) The lessee shall submit a compliance schedule for the application of BACT. If it is necessary to cease operations to allow for the installation of emission controls, the lessee may apply for a suspension of operations under the provisions of § 250.10 of this part.

(f) *Review of facilities with emissions below the exemption amount.* If, during the review of the information required under paragraph (a)(6) of this section, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is

not significantly affecting the air quality of an onshore area of the State.

(g) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional Supervisor, emissions from the facility following the installation of emission controls. The lessee shall submit this information monthly in a manner and form approved or prescribed by the Regional Supervisor.

(h) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988]

Subpart D—Oil and Gas Drilling Operations

§250.50 Control of wells.

The lessee shall take necessary precautions to keep its wells under control at all times. The lessee shall utilize the best available and safest drilling technology in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to flow or kick. The lessee shall utilize personnel who are trained and competent and shall utilize and maintain equipment and materials necessary to assure the safety and protection of personnel, equipment, natural resources, and the environment.

§250.51 General requirements.

(a) *Fitness of drilling unit.* (1) Drilling units shall be capable of withstanding the oceanographic, meteorological, and ice conditions for the proposed season and location of operations.

(2) Prior to commencing operation, drilling units shall be available for complete inspection by the District Supervisor.

(3) The lessee shall provide information and data on the fitness of the drilling unit to perform the proposed drilling operation. The information shall be submitted with or prior to the submission of Form MMS–123, Application for Permit to Drill (APD), in accordance with §250.64. The District Supervisor may require the submission of a third-party review of the design of drilling units which are of a unique design and/or not proven for use in the proposed environment if the District Supervisor believes that the information submitted by the lessee is insufficient to demonstrate suitability of the unit for use at the proposed drill site. A design Certified Verification Agent approved in accordance with §250.133 of this part shall be used for any required third-party review.

(b) *Drilling unit safety devices.* (1) No later than May 31, 1989, all drilling units shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the driller's report.

(2) No later than May 31, 1989, diesel-engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

(c) *Oceanographic, meteorological, and drilling unit performance data.* Where such information is not otherwise readily available, upon request of the District Supervisor, lessees shall collect and report oceanographic, meteorological, and drilling unit performance data, and monitor ice conditions, if applicable, during the period of operations. The type of information to be collected and reported will be determined by the District Supervisor in the interests of safe conduct of operations and the structural integrity of the drilling unit.

(d) *Foundation requirements.* When the lessee fails to provide sufficient information pursuant to §§250.33 and 250.34 of this part to support a determination that the seafloor is capable of supporting a specific bottom-founded drilling unit under the site-specific soil and oceanographic conditions, the District Supervisor may require that additional

surveys and soil borings be performed and the results be submitted for review and evaluation by the District Supervisor before approval is granted for commencing drilling operations.

(e) *Tests, surveys, and samples.* (1) The lessee shall conduct tests, obtain well and mud logs or surveys, and take samples to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, and water; and the amount of pressure in the formations penetrated. The lessee shall take formation samples or cores to determine the identity, fluid content, and characteristics of any penetrated formation in accordance with requirements approved or prescribed by the District Supervisor.

(2) Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 1,000 feet during the normal course of drilling. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 100 feet in all portions of the hole when angle-changes are planned.

(3) On both vertical and directionally drilled wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 500 feet prior to or upon setting surface or intermediate casing, liners, and at total depth. Composite directional surveys shall be prepared with the interval shown from the bottom of the conductor casing or, in the absence of conductor casing, from the bottom of the drive or structural casing to total depth. In calculating all surveys, a correction from the true north to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north shall be made after making the magnetic-to-true-north correction. A composite dipmeter directional survey or a composite measurement-while-drilling (MWD) directional survey including a listing of the directionally computed inclinations and azimuths on a well classified as vertical will be acceptable as fulfilling the applicable requirements of this paragraph. In the event a composite MWD survey is run, a multishot survey shall be obtained at each casing point in order to confirm the MWD results.

(4) Wells are classified as vertical if the calculated average of inclination readings weighted by the respective interval lengths between readings from surface to drilled depth does not exceed 3 degrees from the vertical. When the calculated average inclination readings weighted by the length of the respective interval between readings from the surface to drilled depth exceeds 3 degrees, the well is classified as directional.

(5) The Regional Supervisor at the request of a holder of an adjoining lease may, for the protection of correlative rights, furnish a copy of the directional survey for a well drilled within 500 feet of the adjacent lease to that leaseholder.

(f) *Fixed drilling platforms.* Applications for installation of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with the provisions of subpart I, Platforms and Structures, of this part. Mobile drilling units which have their jacking equipment removed or have been otherwise immobilized are classified as fixed drilling platforms.

(g) *Equipment movement.* The movement of drilling rigs and related equipment on and off an offshore platform or from well to well on the same offshore platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving such rigs and related equipment, unless otherwise approved by the District Supervisor. A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out.

(h) *Emergency shutdown system.* When drilling operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an Emergency Shutdown

System (ESD) manually controlled station shall be installed near the driller's console.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 55 FR 47752, Nov. 15, 1990; 58 FR 49928, Sept. 24, 1993]

§ 250.52 Welding and burning practices and procedures.

(a) *General requirements.* (1) For the purpose of this rule, the terms *welding* and *burning* are defined to include arc or fuel-gas (acetylene or other gas) cutting and arc or fuel-gas welding.

(2) All offshore welding and burning shall be minimized by onshore fabrication when feasible. The requirements set forth in paragraphs (b), (c), and (d) of this section shall be applicable to any welding or burning practice or procedure performed on the following:

(i) An offshore mobile drilling unit during the drilling mode;

(ii) A mobile workover unit during any drilling, completion, recompletion, remedial, repair, stimulation, or other workover activity;

(iii) A platform, structure, artificial island, or other installation during any drilling, well-completion, well-workover, or production operation; and

(iv) A platform, structure, artificial island, or other installation which contains a well open to a hydrocarbon-bearing zone.

(3) All water-discharge-point sources from hydrocarbon-handling vessels shall be monitored in order to stop welding and burning operations in case flammable fluids are discharged as a result of equipment upset or malfunction.

(4) Equipment containing hydrocarbons or other flammable substances shall be relocated at least 35 feet horizontally from the work site. Similar equipment located at a lower elevation where slag, sparks, or other burning materials could fall shall be relocated at least 35 feet from the point of impact. If relocation is impractical, either the equipment shall be protected with flame-proofed covers or otherwise shielded with metal or fire-resistant guards or curtains, or the contents shall have been rendered inert.

(b) *Welding, burning, and hot tapping plan.* Each lessee shall submit for approval by the District Supervisor a ''Welding, Burning, and Hot Tapping Safe Practices and Procedures Plan'' prior to beginning the first drilling and/or production operations on a lease. The plan shall include the qualification standards or requirements for personnel who the lessee will authorize to conduct welding, burning, and hot tapping operations and the methods by which the lessee will assure that only trained personnel who meet such standards or requirements are utilized. A copy of this plan and approval letter shall be available on the facility where the welding is conducted. Any person designated as a welding supervisor shall be thoroughly familiar with this plan. An approved plan is required prior to conducting any welding, burning, or hot tapping operation. All welding and burning equipment shall be inspected by the welding supervisor or the lessee's designated person in charge prior to beginning any welding, burning, or hot tapping. All engine-driven welding machines shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition, oxygen and fuel gas bottles shall be secured in a safe place, and leak-free hoses shall be equipped with proper fittings, gauges, and regulators.

(c) *Designated safe-welding and burning areas.* The lessee may establish and designate areas determined to be safe-welding areas. These designated areas shall be identified in the plan, and a drawing showing the location of these areas shall be maintained on the facility.

(d) *Undesignated welding and burning areas.* All welding and burning, which cannot be done in an approved safe-welding area, shall be performed in compliance with the following:

(1) Prior to the commencement of any of these operations, the lessee's designated person in charge at the installation shall inspect the qualifications of the welder(s) to assure that the welder(s) is properly qualified in accordance with the approved qualification standards or requirements for welders. The designated person in charge and the welder(s) shall inspect the work area and area(s) at elevations below the work area where slag,

sparks, or other hot materials could fall for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding and burning operation, the designated person-in-charge shall issue a written authorization for the work.

(2) During these welding or burning operations, one or more persons shall be designated as a fire watch. The person(s) assigned as a fire watch shall have no other duties while actual welding or burning operations are in progress. If the operation is to be in an area which is not equipped with a gas detector, the fire watch shall also maintain a continuous surveillance with a portable gas detector during the welding and burning operation. The fire watch shall remain on duty for a period of 30 minutes after welding or burning operations have been completed.

(3) Prior to any of these operations, the fire watch shall have in their possession firefighting equipment in a usable condition.

(4) No welding or burning operation, other than approved hot tapping, shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and are determined to be safe for welding or burning by the designated person in charge.

(5) If drilling, well-completion, well-workover, or wireline operations are in progress, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) in the area where drilling, well-completion, well-workover, or wireline operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded.

(6) If welding or burning operations are conducted in or within 10 feet of a well-bay or production area, all producing wells in the well-bay or production area shall be shut in at the surface safety valve.

§ 250.53 Electrical equipment.

The following requirements shall be applicable to all electrical equipment on all platforms, artificial islands, fixed structures, and their facilities:

(a) All engines with electrical ignition systems shall be equipped with a low-tension ignition system designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture or substance.

(b) All areas shall be classified in accordance with API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities.

(c) All electrical installations shall be made in accordance with API RP 14F, Design and Installation of Electrical Systems for Offshore Production Platforms, except sections 7.4, Emergency Lighting and 9.4, Aids to Navigation Equipment.

(d) Maintenance of electrical systems shall be by personnel who are trained and experienced with the area classifications, distribution system, performance characteristics and operation of the equipment, and with the hazards involved.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 61 FR 60024, Nov. 26, 1996]

§ 250.54 Well casing and cementing.

(a) *General requirements.* (1) For the purpose of this subpart, the casing strings in order of normal installation are as follows:

(i) Drive or structural,

(ii) Conductor,

(iii) Surface,

(iv) Intermediate, and

(v) Production casing.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing and quantity and quality of cement in a manner necessary to prevent release of fluids from any stratum through the wellbore (directly or indirectly) into offshore waters, prevent communication between separate hydrocarbon-bearing strata, protect freshwater aquifers from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids. Cement composition, placement techniques, and waiting time shall be designed and conducted so that the cement in place behind the bottom 500 feet of casing or total length of annular cement fill, if less,

attains a minimum compressive strength of 500 pounds per square inch (psi). Cement placed across permafrost zones shall be designed to set before freezing and have a low heat of hydration.

(3) The lessee shall install casing designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof. Safety factors in the casing program design shall be of sufficient magnitude to provide well control during drilling and to assure safe operations for the life of the well. Any portion of an annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid which has a freezing point below the minimum permafrost temperature to prevent internal freezeback and which is treated to minimize corrosion.

(4) In cases where cement has filled the annular space back to the mud line, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment if the District Supervisor determines that subsurface protection against damage to freshwater aquifers and permafrost zones and against damage caused by adverse loads, pressures, and fluid flows is not jeopardized.

(5) If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall re-cement or take other remedial actions as approved by the District Supervisor.

(6) A pressure-integrity test shall be run below the surface casing, the intermediate casing(s), and liner(s) used as intermediate casing(s). The District Supervisor may require a pressure-integrity test to be run at the conductor casing shoe due to local geologic conditions or planned casing setting depths. Pressure-integrity tests shall be made after drilling new hole below the casing shoe and before drilling more than 50 feet of new hole below a respective casing string. These tests shall be conducted either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as specified in the approved APD. A safe margin, as approved by the District Supervisor, shall be maintained between the mud weight in use and the equivalent mud weight at the casing shoe as determined in the pressure-integrity test. Drilling operations shall be suspended when the safe margin is not maintained. Pressure-integrity and pore-pressure test results and related hole-behavior observations, such as gas-cut mud and well kicks made during the course of drilling, shall be used in adjusting the drilling mud program and the approved setting depth of the next casing string. The results of all tests and of hole-behavior observations made during the course of drilling related to formation integrity and pore pressure shall be recorded in the driller's report.

(b) *Drive or structural casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth as may be prescribed or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, a quantity of cement sufficient to fill the annular space back to the mud line shall be used.

(c) *Conductor and surface casing requirements.* (1) *Conductor and surface casing setting depths.* Conductor and surface casing design and setting depths shall be based upon relevant engineering and geologic factors including the presence or absence of hydrocarbons, potential hazards, and water depths. The approved casing setting depths may be adjusted when the change is approved by the District Supervisor to permit the casing shoe to be set in a competent formation or below formations which should be isolated from the wellbore by casing for safer drilling operations. However, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas or, if the presence of oil or gas is unknown, upon encountering a formation containing oil or gas. Upon encountering

unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval. The District Supervisor may permit a lessee to drill a well without setting conductor casing provided the information from approved logging and mud-monitoring programs for wells previously drilled in the immediate vacinity combined with other available geologic data are sufficient to demonstrate the absence of shallow hydrocarbons or hazards.

(2) *Conductor casing cementing requirements.* Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line except as applicable to the bottom of an excavation (glory hole) or to the surface of an artificial island. Cement fill in annular spaces shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible, additional quantities of cement shall be used to assure fill to the mud line.

(3) *Surface casing cementing requirements.* (i) Surface casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, surface casing shall be cemented with a quantity of cement that fills the calculated annular space to the mud line, or as approved or prescribed by the District Supervisor.

(ii) For floating drilling operations, a lesser volume of cement may be used to prevent sealing the annular space between the conductor casing and surface casing if the District Supervisor determines that the uncemented space is necessary to provide protection from burst and collapse pressures which may be applied inadvertently to the annulus between casings during blowout preventer (BOP) testing operations. Any annular space open to the drilled hole shall be sealed in accordance with the requirements for abandonment in subpart G, Abandonment of Wells, of this part.

(d) *Intermediate casing requirements.* (1) Intermediate casing string(s) shall be set for protection when geologic characteristics or wellbore conditions, as anticipated or as encountered, so indicate.

(2) Quantities of cement that cover and isolate all hydrocarbon-bearing zones in the well and isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 500 feet above the zones to be isolated or 500 feet above the casing shoe in wells where zonal coverage is not required.

(3) If a liner is to be used as an intermediate string below a surface casing string, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for intermediate casing. When a liner is to be used as production casing below a surface casing string, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

(e) *Production casing requirements.* (1) Production casing shall be cemented to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon-bearing zone shall be used.

(2) When a liner is to be used as production casing below intermediate casing, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for the production casing.

§ 250.55 Pressure testing of casing.

(a) Prior to drilling the plug after cementing and in the cases of plugs in production casing strings and liners not planned to be subsequently drilled out, all casings, except the drive or structural casing, shall be pressure tested to 70 percent of the minimum internal-yield pressure of the casing or as otherwise approved or required by the District Supervisor. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing pressure tested

again. Additional remedial actions shall be taken until a satisfactory pressure test is obtained. The results of all casing pressure tests shall be recorded in the driller's report.

(b) Each production liner lap shall be tested to a minimum of 500 psi above formation fracture pressure at the shoe of the casing into which the liner is lapped, or as otherwise approved or required by the District Supervisor. The drilling liner-lap test pressure shall be equal to or exceed the pressure that will be encountered at the liner lap when conducting the planned pressure-integrity test below the liner shoe. The test results shall be recorded on the driller's report. If the test indicates an improper seal, remedial action shall be taken which provides a proper seal as demonstrated by a satisfactory pressure test.

(c) In the event of prolonged drill-pipe rotation within a casing string run to the surface or extended operations such as milling, fishing, jarring, washing over, and other operations which could damage the casing, the casing shall be pressure tested or evaluated by a logging technique such as a caliper log every 30 days. The evaluation results shall be submitted to the District Supervisor with a determination of effects of operations on the integrity of the casing for continued service during drilling operations and over the producing life of the well. If the integrity of the casing in the well has deteriorated to an unsafe level, remedial operations shall be conducted or additional casing set in accordance with a plan approved by the District Supervisor prior to continuing drilling operations.

(d) After cementing any string of casing other than the structural casing string, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§ 250.56 Blowout preventer systems and system components.

(a) *General.* The BOP systems and system components shall be designed, installed, used, maintained, and tested to assure well control.

(b) *BOP stacks.* The BOP stacks shall consist of an annular preventer and the number of ram-type preventers as specified under paragraphs (e)(1), (f), and (g) of this section. The pipe rams shall be of a proper size(s) to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP component shall exceed the anticipated surface pressure to which it may be subjected. The District Supervisor may approve a lower working pressure rating for the annular preventer if the lessee demonstrates that the anticipated or actual well conditions will not place demands above its rated working pressure. (Refer to related requirements in § 250.64(f)(3)(ii) of this part.)

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system which shall provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

(2) A backup to the primary accumulator-charging system which shall be automatic, supplied by a power source independent from the power source to the primary accumulator-charging system, and possess sufficient capability to close all BOP components and hold them closed.

(3) At least one operable remote BOP control station in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

(4) A drilling spool with side outlets if side outlets are not provided in the

body of the BOP stack to provide for separate kill and choke lines.

(5) For surface BOP systems, a choke and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled except that a check valve may be installed on the kill line in lieu of the remotely controlled valve provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. For subsea BOP systems, a choke and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line and at least one of the valves on the kill line shall be remotely controlled.

(6) A fill-up line above the uppermost preventer.

(7) A choke manifold suitable for the anticipated pressures to which it may be subjected, method of well control to be employed, surrounding environment, and corrosiveness, volume, and abrasiveness of fluids. The choke manifold shall also meet the following requirements:

(i) Manifold and choke equipment subject to well and/or pump pressure shall have a rated working pressure at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor;

(ii) All components of the choke manifold system shall be protected from the danger, if any, of freezing by heating, draining, or filling with proper fluids; and

(iii) When buffer tanks are installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together, isolation valves shall be installed on each line.

(8) Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold with pressure ratings at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor.

(9) A wellhead assembly with a rated working pressure that exceeds the anticipated surface pressure to which it may be subjected.

(10) The following system components:

(i) On a conventional drilling rig, a kelly cock installed below the swivel (upper kelly cock), essentially full-opening, and a similar valve of such design that it can be run through the BOP stack (strippable) installed at the bottom of the kelly (lower kelly cock). With a mud motor in service and while using drill pipe in lieu of a kelly, one kelly cock located above and one strippable kelly cock located below the joint of drill pipe employed in lieu of a kelly. On a top-drive system equipped with a remote controlled valve, a second and lower strippable valve of a conventional kelly cock or comparable type either manually or remotely controlled. All required manual and remotely controlled valves of a kelly cock or comparable type in a top-drive system shall be essentially full-opening and tested according to the test pressure and test frequency as stated in § 250.57(d) of this part. A wrench to fit each manually operable valve in a conventional drilling rig, mud motor, and top-drive system shall be stored in a location readily accessible to the drilling crew.

(ii) An inside BOP and an essentially full-opening drill-string safety valve in the open position on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew.

(iii) A safety valve available on the rig floor assembled with the proper connection to fit the casing string being run in the hole.

(11) Locking devices installed on the ram-type preventers.

(e) *Subsea BOP requirements.* (1) Prior to drilling below surface and intermediate casing, a BOP system shall be installed consisting of at least four remote controlled, hydraulically operated BOP's including at least two equipped with pipe rams, one with blind-shear rams, and one annular type. A subsea accumulator closing unit or a suitable alternate approved by the District Supervisor is required

to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. When proposed casing setting depths or local geology indicate the need for a BOP to provide safety during the drilling of the surface hole, the District Supervisor may require that a subsea BOP system be installed prior to drilling below the conductor casing.

(2) The BOP system shall include operable dual-pod control systems necessary to ensure proper and independent operation of the BOP system functions when drilling below the surface casing.

(3) Prior to the removal of the marine riser, the riser shall be displaced with seawater. Sufficient hydrostatic pressure or other suitable precautions, such as mechanical or cement plugs or closing the BOP, shall be maintained within the wellbore to compensate for the reduction in pressure and to maintain a safe controlled well condition.

(4) Any necessary repair or replacement of the BOP system or a system component after installation shall be accomplished under safe controlled conditions, (e.g., after casing has been cemented but prior to drilling out the casing shoe or by setting a cement plug, bridge plug, or a packer).

(5) When a subsea BOP system is to be used in an area which is subject to ice scour, the BOP stack shall be placed in an excavation (glory hole) of sufficient depth to assure that the top of the stack is below the deepest probable ice-scour depth.

(f) *Surface BOP requirements.* Prior to drilling below surface or intermediate casing, a BOP system shall be installed consisting of at least four remote controlled, hydraulically operated BOP's including at least two equipped with pipe rams, one with blind rams, and one annular type.

(g) *Tapered drill-string operations.* (1) Prior to commencing tapered drill-pipe operations, the BOP stack shall be equipped with conventional and/or variable-bore pipe rams installed in two or more ram cavities to provide the following:

(i) Two sets of pipe rams capable of sealing around the larger size drill string, and

(ii) One set of pipe rams capable of sealing around the smaller size drill string.

(2) Subsea BOP systems shall have blind-shear ram capability. Surface BOP systems shall have blind ram capability.

§250.57 Blowout preventer systems tests, actuations, inspections, and maintenance.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a low pressure of 200 to 300 psi.

(b) Surface ram-type BOP's and the choke manifold shall be pressure tested with water to rated working pressure or as otherwise approved by the District Supervisor. The annular-type BOP shall be pressure tested with water to 70 percent of its rated working pressure or as otherwise approved by the District Supervisor.

(c) Subsea BOP system components shall be stump pressure tested at the surface with water to their rated working pressure, except that the annular-type BOP shall not be pressure tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the seafloor, the ram-type BOP's and choke manifold shall be pressure tested to rated working pressure or as otherwise approved by the District Supervisor. The annular preventer shall be pressure tested to 70 percent of its rated working pressure or as otherwise approved by the District Supervisor.

(d) In conjunction with the weekly pressure test of surface and subsea BOP systems required in paragraph (e) of this section, the choke manifold valves; upper and lower kelly cocks; top-drive, inside-BOP, and the drill-string safety valves shall be pressure tested to pipe-ram test pressures or otherwise approved by the District Supervisor. Safety valves assembled with proper casing connections shall be actuated prior to running casing.

(e) Surface and subsea BOP systems shall be pressure tested as follows:

(1) When installed.

(2) Before drilling out each string of casing or before continuing operations in cases where the cement is not drilled out.

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations and pods. If either control station or pod is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between BOP tests is allowed when there is stuck drill pipe or pressure-control operations and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operations resume. The reason for postponing pressure testing shall be entered into the driller's report. Pressure testing shall be performed at intervals to allow each drilling crew to operate the equipment. The weekly pressure test is not required for blind and blind-shear rams.

(4) Blind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than that necessary to indicate proper operation of the rams is not required.

(5) Variable bore-pipe rams shall be pressure-tested against all sizes of pipe in use, excluding drill collars and bottom-hole tools.

(6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly but limited to the affected component.

(f) All BOP systems and marine risers shall be inspected and maintained to assure that the equipment will function properly. The BOP systems and marine risers shall be visually inspected at least once each day if the weather and sea conditions permit the inspection. Inspection of BOP systems and marine risers may be accomplished by the use of television equipment. The District Supervisor may approve alternate methods of inspection of marine risers on dynamic-positioned rigs. Casing risers on fixed structures and jackup rigs are not subject to the daily underwater inspection requirement.

(g) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test interval for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(h) The time, date, and results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine risers shall be recorded in the driller's report. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the driller's report may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the driller's report. For a subsea system, the pod used during the test shall be identified in the driller's report.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the driller's report.

(4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records including pressure charts, driller's report, and referenced documents pertaining to BOP tests, actuations, and inspections, shall be available for MMS review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all such records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 1914, Jan. 18, 1991]

§ 250.58 Well-control drills.

(a) Well-control drills shall be conducted for each drilling crew in accordance with the following requirements:

(1) Drills shall be designed to acquaint each crew member with each member's function at the particular test station so each member can perform their functions promptly and efficiently.

(2) A well-control drill plan, applicable to the particular site, shall be prepared for each crew member outlining the assignments each member is to fulfill during the drill and establishing a prescribed time for the completion of each portion of the drill. A copy of the complete well-control drill plan shall be posted on the rig floor and/or bulletin board.

(3) The drill shall be carried out during periods of activity selected to minimize the risk of sticking the drill pipe or otherwise endangering the operation. In each of these drills, the reaction time of participants shall be measured up to the point when the designated person is prepared to activate the closing sequence of the BOP system. The total time for the crew to complete its entire drill assignment shall also be measured. This operation shall be recorded on the driller's report as ''Well-Control Drill.'' All drills shall be initiated by the toolpusher through the raising of the float on the pit-level device, activating the mud-return indicator, or its equivalent. This operation shall be performed at least once each week (well conditions permitting) with each crew. The drills shall be timed so they will cover a range of different operations which include on-bottom drilling and tripping. A diverter drill shall be developed and conducted in a similar manner for shallow operations.

(4) *On-bottom drilling.* A drill conducted while on bottom shall include the following as practicable:

(i) Detect kick and sound alarm;

(ii) Position kelly and tool joints so connections are accessible from floor, but tool joints are clear of sealing elements in BOP systems, stop pumps, check for flow, close in the well;

(iii) Record time;

(iv) Record drill-pipe pressure and casing pressure;

(v) Measure pit gain and mark new level;

(vi) Estimate volume of additional mud in pits;

(vii) Weight sample of mud from suction pit;

(viii) Check all valves on choke manifold and BOP system for correct position (open or closed);

(ix) Check BOP system components and choke manifold for leaks;

(x) Check flow line and choke exhaust lines for flow;

(xi) Check accumulator pressure;

(xii) Prepare to extinguish sources of ignition;

(xiii) Alert standby boat or prepare safety capsule for launching;

(xiv) Place crane operator on duty for possible personnel evacuation;

(xv) Prepare to lower escape ladders and prepare other abandonment devices for possible use;

(xvi) Determine materials needed to circulate out kick; and

(xvii) Time drill and enter drill report on driller's report.

(5) *Tripping pipe.* A drill conducted during a trip shall include the following as practicable:

(i) Detect kick and sound alarm;

(ii) Install safety valve, close safety valve;

(iii) Position pipe, prepare to close annular preventer;

(iv) Install inside preventer, open safety valve;

(v) Record time;

(vi) Record casing pressure;

(vii) Check all valves on choke manifold and BOP system for correct position (open or closed);

(viii) Check for leaks on BOP system component and choke manifold;

(ix) Check flow line and choke exhaust lines for flow;

(x) Check accumulator pressure;

(xi) Prepare to extinguish sources of ignition;

(xii) Alert standby boat or prepare safety capsule for launching;

(xiii) Place crane operator on duty for possible personnel evacuation;

(xiv) Prepare to lower escape ladders and prepare other abandonment devices for possible use;

(xv) Prepare to strip back to bottom; and

(xvi) Time drill and enter drill report on driller's report.

(b) A well-control drill may be required by a Minerals Management Service (MMS) authorized representative after consulting with the lessee's senior representative present.

§ 250.59 Diverter systems.

(a) When drilling a conductor or surface hole, all drilling units shall be

equipped with a diverter system consisting of a diverter sealing element, diverter lines, and control systems unless otherwise approved by the District Supervisor for floating drilling operations. The diverter system shall be designed, installed, and maintained so as to divert gases, water, mud, and other materials away from the facilities and personnel.

(b) No later than May 31, 1990, diverter systems shall be in compliance with the requirements of this section. The requirements applicable to diverters which were in effect April 1, 1988 shall remain in effect until May 31, 1990.

(c) The diverter system shall be equipped with remote-controlled valves in the flow and vent lines that can be operated from at least one remote-control station in addition to the one on the drilling floor. Any valve used in a diverter system shall be full-opening. No manual or butterfly valve shall be installed in any part of the diverter system. There shall be a minimum number of turns in the vent line(s) downstream of the spool outlet flange and the radius of curvature of turns shall be as large as practicable. All right-angle and sharp turns shall be targeted. Flexible hose may be used for diverter lines instead of rigid pipe if the flexible hose has integral end couplings. The entire diverter system shall be firmly anchored and supported to prevent whipping and vibration. All diverter control instruments and lines shall be protected from physical damage from thrown and falling objects.

(d) For drilling operations conducted with a surface wellhead configuration, the following shall apply:

(1) If the diverter system utilizes only one spool outlet, branch lines shall be installed to provide downwind diversion capability; and

(2) No spool outlet or diverter line internal diameter shall be less than 10 inches, except that dual spool outlets are acceptable provided that each outlet has a minimum internal diameter of 8 inches and that both outlets are piped to overboard lines and that each line downstream of the changeover nipple at the spool has a minimum internal diameter of 10 inches.

(e) For drilling operations conducted where a floating or semisubmersible type of drilling vessel is used and drilling fluids are circulated to the drilling vessel, the following shall apply:

(1) If the diverter system utilizes only one spool outlet, branch lines shall be installed to provide downwind diversion capability;

(2) No spool outlet or diverter line internal diameter shall be less than 12 inches; and

(3) Dynamically positioned drill ships may be equipped with a single vent line provided appropriate vessel heading is maintained to allow for downwind diversion.

(f) The diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psi when nippled up on conductor casing with a surface wellhead configuration. No more than 7 days shall elapse between subsequent similar pressure tests. For surface and subsea wellhead configurations, the diverter sealing element, diverter valves, and diverter-control systems, including the remote control system, shall be actuation-tested and the vent lines flow tested when first installed. Subsequent actuation tests shall be conducted not less than once every 24-hour period thereafter alternating between control stations. All pressure test, flow test, and actuation results shall be recorded in the driller's report.

(g) Diverter systems and components for use in subfreezing conditions shall be suitable for use under these conditions.

§ 250.60 Mud program.

(a) *General requirements.* The quantities, characteristics, use, and testing of drilling mud and the related drilling procedures shall be designed and implemented to prevent the loss of well control.

(b) *Mud control.* (1) Before starting out of the hole with drill pipe, the mud shall be properly conditioned by circulation with the drill pipe just off bottom to the extent that a volume of drilling mud equal to the annular volume is displaced. This procedure may be omitted if proper documentation in the driller's report shows the following:

(i) There is no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

(ii) The weight of the returning mud is essentially the same as the weight of the mud entering the hole. In the event that the returning mud is lighter than the entering mud by a weight differential equal to or greater than 0.2 pounds per gallon (1.5 pounds per cubic foot), the mud shall be circulated until a volume of drilling mud equal to the annular volume is displaced, and the mud properties measured to assure that there has been no influx of gas or liquid.

(iii) Other mud properties recorded on the daily drilling log are within the limits established by the approved mud program.

(2) When mud in the hole is circulated, the driller's report shall be so noted.

(3) When coming out of the hole with drill pipe, the annulus shall be filled with mud before the change in mud level decreases the hydrostatic pressure by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted near the driller's station. A mechanical, volumetric, or electronic device for measuring the amount of mud required to fill the hole shall be utilized.

(4) Drill pipe and downhole tool running and pulling speeds shall be at controlled rates so as not to induce an influx of formation fluids from the effects of swabbing nor cause a loss of drilling fluid and corresponding hydrostatic pressure decrease from the effects of surging.

(5) When there is an indication of swabbing or influx of formation fluids, the safety devices and measures necessary to control the well shall be employed. The mud shall be circulated and conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

(6) For each casing string, the maximum pressure to be contained under the BOP shall be posted near the driller's station.

(7) In areas where permafrost and/or hydrate zones may be present or are known to be present, drilling fluid temperatures shall be controlled or other measures taken to drill safely through those zones.

(8) An operable mud-gas separator and operable degasser shall be installed in the mud system prior to commencement of drilling operations and shall be maintained for use throughout the drilling of the well.

(9) The mud in the hole shall be circulated or reverse-circulated prior to pulling the drill-stem test tools from the hole. If circulating out test fluid is not feasible, test fluids may be bullheaded out of the drill-stem test string and tools with an appropriate kill fluid prior to pulling the test tools.

(c) *Mud-testing and monitoring equipment.* (1) Mud-testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently, as conditions warrant. Such tests shall be conducted in accordance with industry-accepted practices and shall include mud density, viscosity, and gel strength, hydrogen-ion concentration (pH), filtration, and other tests as may be deemed necessary by the District Supervisor in the interests of monitoring and maintaining mud quality for safe operations, prevention of downhole equipment problems, and for kick detection. The results of these tests shall be recorded in the driller's report.

(2) The following mud-system monitoring equipment shall be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

(i) Recording mud-pit level indicator to determine mud-pit volume gains and losses. This indicator shall include both a visual and an audible warning device.

(ii) Mud-volume measuring device to accurately determine mud volumes required to fill the hole on trips.

(iii) Mud-return indicator devices which indicate the relationship between mud-return flow rate and pump discharge rate. This indicator shall include both a visual and an audible warning device.

(iv) Gas-detecting equipment to monitor the drilling mud returns with indicators located in the mud-logging compartment or on the rig floor. If the indicators are only in the mud-logging compartment, there shall be a means of immediate communication with the rig floor, and the gas-detecting equipment shall be continually manned. If the indicators are on the rig floor only, an audible alarm shall be installed.

(d) *Mud quantities.* (1) Quantities of mud and mud materials at the drill site shall be utilized, maintained, and replenished as necessary to ensure well control. Those quantities shall be based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

(2) Daily inventories of mud and mud materials including weight materials and additives at the drill site shall be recorded and those records maintained at the well site.

(3) Drilling operations shall be suspended in the absence of sufficient quantities of mud and mud materials to maintain well control.

(e) *Safety precautions in mud-handling areas.* Mud-handling areas which are classified as per API RP 500B where dangerous concentrations of combustible gas may accumulate shall be equipped with ventilation systems and gas monitors as described below no later than May 31, 1989. Regulatory requirements in effect on April 1, 1988 are applicable until May 31, 1989.

(1) Be ventilated with high-capacity mechanical ventilation systems capable of replacing the air once every 5 minutes or 1.0 cubic feet of air-volume flow per minute per square foot of area, whichever is greater, unless such ventilation is provided by natural means. If not continuously activated, mechanical ventilation systems shall be activated on signal from gas detectors that are operational at all times indicating the presence of 1 percent or more of gas by volume.

(2) Be maintained at a negative pressure relative to an adjacent area if mechanical ventilation is installed to meet the requirements in paragraph (e)(1) of this section and discharges may be hazardous. The negative pressure areas shall be protected with at least one of the following: (i) A pressure-sensitive alarm, (ii) open-door alarms on each access to the area, (iii) automatic door-closing devices, (iv) air locks, or (v) other devices as approved by the District Supervisor.

(3) Be fitted with gas detectors and alarms except in open areas where adequate ventilation is provided by natural means.

(4) Be equipped with either explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases. Where air is used for pressuring, the air intake shall be located outside of, and as far as practicable from, hazardous areas.

(5) Mechanical ventilation systems shall be fitted with alarms which are activated upon a failure of the system.

(6) Gas detection systems shall be tested for operation and recalibrated at a frequency such that no more than 90 days shall elapse between tests.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990]

§ 250.61 Securing of wells.

A downhole safety device such as a cement plug, bridge plug, or packer shall be timely installed when drilling operations are interrupted by events such as those which force evacuation of the drilling crew, prevent station keeping, or require repairs to major drilling or well-control equipment. In floating drilling operations, the use of blind-shear rams or pipe rams and an inside BOP may be approved by the District Supervisor in lieu of the above requirements if supported by evidence of special circumstances and/or the lack of sufficient time.

§ 250.62 Field drilling rules.

When geological and engineering information available in a field enables a District Supervisor to determine specific operating requirements appropriate to wells to be drilled in the field, field drilling rules may be established on the initiative of the District Supervisor, or in response to a request from a lessee. Such rules may modify the requirements of this subpart. After field drilling rules have been established, development wells to which such rules apply shall be drilled in accordance with such rules and other requirements

of this subpart. Field drilling rules may be amended or cancelled for cause at any time upon the initiative of the District Supervisor or upon the approval of a request by a lessee.

§250.63 Supervision, surveillance, and training.

(a) The lessee shall provide onsite supervision of drilling operations on a 24-hour per day basis.

(b) From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with BOP's, bridge plugs, packers, or cement plugs.

(c) Lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of Subpart O of this part and MMS Training Standard MMS–OCS–T 1, Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling Offshore Locations (Second Edition). Records of specific training which lessee and drilling contractor personnel have successfully completed, the dates of completion, and the names and dates of the courses shall be maintained at the drill site.

§250.64 Applications for permit to drill.

(a) Prior to commencing the drilling of a well under an approved Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, the lessee shall file a Form MMS–123, APD, with the District Supervisor for approval. Prior to commencing operations, written approval from the District Supervisor must be received by the lessee unless oral approval has been given pursuant to §250.6(a).

(b) The APD's for wells to be drilled from mobile drilling units shall include the following:

(1) An identification of the maximum environmental and operational conditions the rig is designed to withstand.

(2) Applicable current documentation of operational limitations imposed by the American Bureau of Shipping classification or other appropriate classification society and either a U.S. Coast Guard Certificate of Inspection or a U.S. Coast Guard Letter of Compliance.

(3) For frontier areas, the design and operating limitations beyond which suspension, curtailment, or modification of drilling or rig operations are required (e.g., vessel motion, offset, riser angle, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability) and the contingency plans which identify actions to be taken prior to exceeding the design or operating limitations of the rig.

(4) A program which provides for safety in drilling operations where a floating or semisubmersible type of drilling vessel is used and formation competency at the structural and/or conductor casing setting depth(s) is (are) not adequate to permit circulation of drilling fluids to the vessel while drilling the conductor and/or surface hole. This program shall include all known pertinent information including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, a schematic diagram indicating the equipment to be installed from the rotary table to the proposed conductor and/or surface casing seat(s), and the contingency plan for moving off location.

(c) The APD's shall include rated capacities of the proposed drilling unit and of major drilling equipment.

(d) In those areas which are subject to subfreezing conditions, the lessee shall furnish evidence that the drilling equipment, BOP system and components, drilling safety systems, diverter systems, and other associated equipment and materials are suitable for drilling operations under subfreezing conditions.

(e) After a drilling unit has been approved for use in an MMS District, the information listed in paragraphs (b) (1), (2), and (3), (c), and (d) of this section need not be resubmitted unless required by the District Supervisor or there are changes in equipment that affect the rated capacity of the unit.

(f) An APD shall include the following in addition to a fully completed Form MMS–123:

(1) A plat, drawn to a scale of 2,000 feet to the inch, showing the surface and subsurface location of the well to

be drilled and of all the wells previously drilled in the vicinity from which information is available. Locations shall be indicated in feet from the block line.

(2) The design criteria considered for the well and for well control, including the following:

(i) Pore pressures.

(ii) Formation fracture gradients.

(iii) Potential lost circulation zones.

(iv) Mud weights.

(v) Casing setting depths.

(vi) Anticipated surface pressures (which for purposes of this section are defined as the pressure which can reasonably be expected to be exerted upon a casing string and its related wellhead equipment). In the calculation of an anticipated surface pressure, the lessee shall take into account the drilling, completion, and producing conditions. The lessee shall consider mud densities to be used below various casing strings, fracture gradients of the exposed formations, casing setting depths, total well depth, formation fluid type, and other pertinent conditions. Considerations for calculating anticipated surface pressure may vary for each segment of the well. The lessee shall include as a part of the statement of anticipated surface pressures the calculations used to determine these pressures during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design.

(vii) If a shallow hazards site survey is conducted, the lessee shall submit with or prior to the submittal of the APD, two copies of a summary report describing the geological and manmade conditions present. The lessee shall also submit two copies of the site maps and data records identified in the survey strategy.

(viii) Permafrost zones, if applicable.

(3) A BOP equipment program including the following:

(i) The pressure rating of BOP equipment.

(ii) A well-control procedure for use of the annular preventer for those wells where the anticipated surface pressure exceeds the rated working pressure of the annular preventer.

(iii) A description of subsea BOP accumulator system or other type of closing system proposed for use.

(iv) A schematic drawing of the diverter system to be used (plan and elevation views) showing spool outlet internal diameter(s); diverter-line lengths and diameters, burst strengths, and radius of curvature at each turn; valve type, size, working pressure rating, and location; the control instrumentation logic; and the operating procedure to be used by lessee or contractor personnel.

(v) A schematic drawing of the BOP stack showing the inside diameter of the BOP stack, and the number of annular, pipe ram, variable-bore pipe ram, blind ram, and blind-shear ram preventers.

(4) A casing program including the following:

(i) Casing size, weight, grade, type of connection, and setting depth;

(ii) Casing design safety factors for tension, collapse, and burst with the assumptions made to arrive at these values; and

(iii) In areas containing permafrost, casing programs that incorporate setting depths for conductor and surface casing based on the anticipated depth of the permafrost at the proposed well location and which utilize the current state-of-the-art methods to safely drill and set casing. The casing program shall provide protection from thaw subsidence and freezeback effect, proper anchorage, and well control.

(5) The drilling prognosis including the following:

(i) Projected plans for coring at specified depths;

(ii) Projected plans for logging;

(iii) Estimated depths to the top of significant marker formations; and

(iv) Estimated depths at which encounters with significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured water are expected.

(6) A cementing program including type and amount of cement in cubic feet to be used for each casing string.

(7) A mud program including the minimum quantities of mud and mud materials, including weight materials, to be kept at the site.

(8) A directional survey program for directionally drilled wells.

(9) A plot of the estimated pore pressures and formation fracture gradients and the proposed mud weights and casing setting depths on the same sheet.

(10) A H_2S Contingency Plan, if applicable, and not submitted previously.

(11) Such other information as may be required by the District Supervisor.

(g) Public information copies of the APD shall be submitted in accordance with §250.17 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§250.65 Sundry notices and reports on wells.

(a) Notices of the lessee's intention to change plans, make changes in major drilling equipment, deepen or plug back a well, or engage in similar activities and subsequent reports pertaining to such operations shall be submitted to the District Supervisor on Form MMS–124, Sundry Notices and Reports on Wells. Prior to commencing operations, written approval must be received from the District Supervisor unless oral approval is obtained.

(b) The Form MMS–124 submitted shall contain a detailed statement of the proposed work that will materially change from the approved work described in the APD. Information submitted shall include the present status of the well, including the production string or last string of casing, the well depth, the present production zones and productive capability, and all other information specified on Form MMS–124. Within 30 days after completion of the work, a subsequent detailed report of all the work done and the results obtained shall be submitted.

(c) A Form MMS–124 with a plat, certified by a registered land surveyor, shall be filed as soon as the well's final surveyed surface location, water depth, and the rotary kelly bushing elevation have been determined.

(d) Public information copies of Sundry Notices and Reports on Wells shall be submitted in accordance with §250.17 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§250.66 Well records.

(a) Complete and accurate records for each well and of all well operations shall be retained for a period of 2 years at the lessee's field office nearest the OCS facility or at another location conveniently available to the District Supervisor. The records shall contain a description of any significant malfunction or problem; all the formations penetrated; the content and character of oil, gas, and other mineral deposits and water in each formation; the kind, weight, size, grade, and setting depth of casing; all well logs and surveys run in the wellbore; and all other information required by the District Supervisor in the interests of resource evaluation, waste prevention, conservation of natural resources, protection of correlative rights, safety, and environment.

(b) When drilling operations are suspended, or temporarily prohibited under the provisions of §250.10 of this part, the lessee shall, within 30 days after termination of the suspension or temporary prohibition or within 30 days after the completion of any activities related to the suspension or prohibition, transmit to the District Supervisor duplicate copies of the records of all activities related to and conducted during the suspension or temporary prohibition on, or attached to, Form MMS–125, Well Summary Report, or Form MMS–124, as appropriate.

(c) Upon request by the Regional or District Supervisor, the lessee shall furnish the following:

(1) Copies of the records of any of the well operations specified in paragraph (a) of this section;

(2) Paleontological reports identifying microscopic fossils by depth and/or washed samples of drill cuttings normally maintained by the lessee for paleontological determinations;

(3) Copies of the daily driller's report at a frequency as determined by the District Supervisor. Items to be reported include spud dates, casing setting depths, cement quantities, casing characteristics, pressure integrity tests, mud weights, kicks, lost returns, and any unusual activities; and

(4) Legible, exact copies of service company reports on cementing, perforating, acidizing, analyses of cores, testing, or other similar services.

(d) As soon as available, the lessee shall transmit copies (field or final prints of individual runs) of logs or charts of electrical, radioactive, sonic, and other well-logging operations, directional-well surveys, and analyses of cores. Composite logs of multiple runs and directional-well surveys shall be transmitted to the District Supervisor in duplicate as soon as available but not later than 30 days after completion of each well.

(e) If the drilling unit moves from the wellbore prior to completing the well, the lessee shall submit to the District Supervisor copies of the well records with completed Form MMS–124, within 30 days after moving from the wellbore.

(f) If the Regional or District Supervisor determines that circumstances warrant, the lessee shall submit any other reports and records of operations, including paleontological interpretations based upon identification of microscopic fossils, in the manner and form prescribed by the Regional or District Supervisor.

(g) Records relating to the drilling of a well shall be retained for a period of 90 days after drilling operations are completed. Records relating to the completion of a well or of any workover activity which materially alters the completion configuration or materially affects or alters a hydrocarbon-bearing zone shall be kept until the well is permanently plugged and abandoned.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.67 Hydrogen sulfide.

(a) *What precautions must I take when operating in an H_2S area?* You must:

(1) Take all necessary and feasible precautions and measures to protect personnel from the toxic effects of H_2S and to mitigate damage to property and the environment caused by H_2S. You must follow the requirements of this section when conducting drilling, well-completion/well-workover, and production operations in zones with H_2S present and when conducting operations in zones where the presence of H_2S is unknown. You do not need to follow these requirements when operating in zones where the absence of H_2S has been confirmed; and

(2) Follow your approved contingency plan.

(b) *Definitions.* Terms used in this section have the following meanings:

Facility means a vessel, a structure, or an artificial island used for drilling, well-completion, well-workover, and/or production operations.

H_2S absent means:

(1) Drilling, logging, coring, testing, or producing operations have confirmed the absence of H_2S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S; or

(2) Drilling in the surrounding areas and correlation of geological and seismic data with equivalent stratigraphic units have confirmed an absence of H_2S throughout the area to be drilled.

H_2S present means that drilling, logging, coring, testing, or producing operations have confirmed the presence of H_2S in concentrations and volumes that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S.

H_2S unknown means the designation of a zone or geologic formation where neither the presence nor absence of H_2S has been confirmed.

Well-control fluid means drilling mud and completion or workover fluid as appropriate to the particular operation being conducted.

(c) *Classifying an area for the presence of H_2S.* You must:

(1) Request and obtain an approved classification for the area from the Regional Supervisor before you begin operations. Classifications are ''H_2S absent,'' H_2S present,'' or ''H_2S unknown'';

(2) Submit your request with your application for permit to drill;

(3) Support your request with available information such as geologic and geophysical data and correlations, well logs, formation tests, cores and analysis of formation fluids; and

(4) Submit a request for reclassification of a zone when additional data indicate a different classification is needed.

(d) *What do I do if conditions change?* If you encounter H_2S that could potentially result in atmospheric concentrations of 20 ppm or more in areas not previously classified as having H_2S present, you must immediately notify MMS and begin to follow requirements for areas with H_2S present.

(e) *What are the requirements for conducting simultaneous operations?* When conducting any combination of drilling, well-completion, well-workover, and production operations simultaneously, you must follow the requirements in the section applicable to each individual operation.

(f) *Requirements for submitting an H_2S Contingency Plan.* Before you begin operations, you must submit an H_2S Contingency Plan to the District Supervisor for approval. Do not begin operations before the District Supervisor approves your plan. You must keep a copy of the approved plan in the field, and you must follow the plan at all times. Your plan must include:

(1) Safety procedures and rules that you will follow concerning equipment, drills, and smoking;

(2) Training you provide for employees, contractors, and visitors;

(3) Job position and title of the person responsible for the overall safety of personnel;

(4) Other key positions, how these positions fit into your organization, and what the functions, duties, and responsibilities of those job positions are;

(5) Actions that you will take when the concentration of H_2S in the atmosphere reaches 20 ppm, who will be responsible for those actions, and a description of the audible and visual alarms to be activated;

(6) Briefing areas where personnel will assemble during an H_2S alert. You must have at least two briefing areas on each facility and use the briefing area that is upwind of the H_2S source at any given time;

(7) Criteria you will use to decide when to evacuate the facility and procedures you will use to safely evacuate all personnel from the facility by vessel, capsule, or lifeboat. If you use helicopters during H_2S alerts, describe the types of H_2S emergencies during which you consider the risk of helicopter activity to be acceptable and the precautions you will take during the flights;

(8) Procedures you will use to safely position all vessels attendant to the facility. Indicate where you will locate the vessels with respect to wind direction. Include the distance from the facility and what procedures you will use to safely relocate the vessels in an emergency;

(9) How you will provide protective-breathing equipment for all personnel, including contractors and visitors;

(10) The agencies and facilities you will notify in case of a release of H_2S (that constitutes an emergency), how you will notify them, and their telephone numbers. Include all facilities that might be exposed to atmospheric concentrations of 20 ppm or more of H_2S;

(11) The medical personnel and facilities you will use if needed, their addresses, and telephone numbers;

(12) H_2S detector locations in production facilities producing gas containing 20 ppm or more of H_2S. Include an ''H_2S Detector Location Drawing'' showing:

(i) All vessels, flare outlets, wellheads, and other equipment handling production containing H_2S;

(ii) Approximate maximum concentration of H_2S in the gas stream; and

(iii) Location of all H_2S sensors included in your contingency plan;

(13) Operational conditions when you expect to flare gas containing H_2S including the estimated maximum gas flow rate, H_2S concentration, and duration of flaring;

(14) Your assessment of the risks to personnel during flaring and what precautionary measures you will take;

(15) Primary and alternate methods to ignite the flare and procedures for sustaining ignition and monitoring the status of the flare (i.e., ignited or extinguished);

(16) Procedures to shut off the gas to the flare in the event the flare is extinguished;

(17) Portable or fixed sulphur dioxide (SO_2)-detection system(s) you will use to determine SO_2 concentration and exposure hazard when H_2S is burned;

(18) Increased monitoring and warning procedures you will take when the

SO_2 concentration in the atmosphere reaches 2 ppm;

(19) Personnel protection measures or evacuation procedures you will initiate when the SO_2 concentration in the atmosphere reaches 5 ppm;

(20) Engineering controls to protect personnel from SO_2; and

(21) Any special equipment, procedures, or precautions you will use if you conduct any combination of drilling, well-completion, well-workover, and production operations simultaneously.

(g) *Training program.*

(1) *When and how often do employees need to be trained?* All operators and contract personnel must complete an H_2S training program to meet the requirements of this section:

(i) Before beginning work at the facility; and

(ii) Each year, within 1 year after completion of the previous class.

(2) *What training documentation do I need?* For each individual working on the platform, either:

(i) You must have documentation of this training at the facility where the individual is employed; or

(ii) The employee must carry a training completion card.

(3) *What training do I need to give to visitors and employees previously trained on another facility?*

(i) Trained employees or contractors transferred from another facility must attend a supplemental briefing on your H_2S equipment and procedures before beginning duty at your facility;

(ii) Visitors who will remain on your facility more than 24 hours must receive the training required for employees by paragraph (g)(4) of this section; and

(iii) Visitors who will depart before spending 24 hours on the facility are exempt from the training required for employees, but they must, upon arrival, complete a briefing that includes:

(A) Information on the location and use of an assigned respirator; practice in donning and adjusting the assigned respirator; information on the safe briefing areas, alarm system, and hazards of H_2S and SO_2; and

(B) Instructions on their responsibilities in the event of an H_2S release.

(4) *What training must I provide to all other employees?* You must train all individuals on your facility on the:

(i) Hazards of H_2S and of SO_2 and the provisions for personnel safety contained in the H_2S Contingency Plan;

(ii) Proper use of safety equipment which the employee may be required to use;

(iii) Location of protective breathing equipment, H_2S detectors and alarms, ventilation equipment, briefing areas, warning systems, evacuation procedures, and the direction of prevailing winds;

(iv) Restrictions and corrective measures concerning beards, spectacles, and contact lenses in conformance with ANSI Z88.2;

(v) Basic first-aid procedures applicable to victims of H_2S exposure. During all drills and training sessions, you must address procedures for rescue and first aid for H_2S victims;

(vi) Location of:

(A) The first-aid kit on the facility;

(B) Resuscitators; and

(C) Litter or other device on the facility.

(vii) Meaning of all warning signals.

(5) *Do I need to post safety information?* You must prominently post safety information on the facility and on vessels serving the facility (i.e,, basic first-aid, escape routes, instructions for use of life boats, etc.).

(h) *Drills. (1) When and how often do I need to conduct drills on* H_2S safety discussions on the facility? You must:

(i) Conduct a drill for each person at the facility during normal duty hours at least once every 7-day period. The drills must consist of a dry-run performance of personnel activities related to assigned jobs.

(ii) At a safety meeting or other meetings of all personnel, discuss drill performance, new H_2S considerations at the facility, and other updated H_2S information at least monthly.

(2) *What documentation do I need?* You must keep records of attendance for:

(i) Drilling, well-completion, and well-workover operations at the facility until operations are completed; and

(ii) Production operations at the facility or at the nearest field office for 1 year.

(i) *Visual and audible warning systems*—(1) *How must I install wind direction equipment?* You must install wind-direction equipment in a location visible at all times to individuals on or in the immediate vicinity of the facility.

(2) *When do I need to display operational danger signs, display flags, or activate visual or audible alarms?*

(i) You must display warning signs at all times on facilities with wells capable of producing H_2S and on facilities that process gas containing H_2S in concentrations of 20 ppm or more.

(ii) In addition to the signs, you must activate audible alarms and display flags or activate flashing red lights when atmospheric concentration of H_2S reaches 20 ppm.

(3) *What are the requirements for signs?* Each sign must be a high-visibility yellow color with black lettering as follows:

Letter height	Wording
12 inches	Danger. Poisonous Gas. Hydrogen Sulfide.
7 inches	Do not approach if red flag is flying.
(Use appropriate wording at right).	Do not approach if red lights are flashing.

(4) *May I use existing signs?* You may use existing signs containing the words ''Danger-Hydrogen Sulfide-H_2S,'' provided the words ''Poisonous Gas. Do Not Approach if Red Flag is Flying'' or ''Red Lights are Flashing'' in lettering of a minimum of 7 inches in height are displayed on a sign immediately adjacent to the existing sign.

(5) *What are the requirements for flashing lights or flags?* You must activate a sufficient number of lights or hoist a sufficient number of flags to be visible to vessels and aircraft. Each light must be of sufficient intensity to be seen by approaching vessels or aircraft any time it is activated (day or night). Each flag must be red, rectangular, a minimum width of 3 feet, and a minimum height of 2 feet.

(6) *What is an audible warning system?* An audible warning system is a public address system or siren, horn, or other similar warning device with a unique sound used only for H_2S.

(7) *Are there any other requirements for visual or audible warning devices?* Yes, you must:

(i) Illuminate all signs and flags at night and under conditions of poor visibility; and

(ii) Use warning devices that are suitable for the electrical classification of the area.

(8) *What actions must I take when the alarms are activated?* When the warning devices are activated, the designated responsible persons must inform personnel of the level of danger and issue instructions on the initiation of appropriate protective measures.

(j) *H_2S-detection and H_2S monitoring equipment.*—(1) *What are the requirements for an H_2S detection system?* An H_2S detection system must:

(i) Be capable of sensing a minimum of 10 ppm of H_2S in the atmosphere; and

(ii) Activate audible and visual alarms when the concentration of H_2S in the atmosphere reaches 20 ppm.

(2) *Where must I have sensors for drilling, well-completion, and well-workover operations?* You must locate sensors at the:

(i) Bell nipple;

(ii) Mud-return line receiver tank (possum belly);

(iii) Pipe-trip tank;

(iv) Shale shaker;

(v) Well-control fluid pit area;

(vi) Driller's station;

(vii) Living quarters; and

(viii) All other areas where H_2S may accumulate.

(3) *Do I need mud sensors?* The District Supervisor may require mud sensors in the possum belly in cases where the ambient air sensors in the mud-return system do not consistently detect the presence of H_2S.

(4) *How often must I observe the sensors?* During drilling, well-completion and well-workover operations, you must continuously observe the H_2S levels indicated by the monitors in the work areas during the following operations:

(i) When you pull a wet string of drill pipe or workover string;

(ii) When circulating bottoms-up after a drilling break;

(iii) During cementing operations;

(iv) During logging operations; and

(v) When circulating to condition mud or other well-control fluid.

(5) *Where must I have sensors for production operations?* On a platform where gas containing H_2S of 20 ppm or greater is produced, processed, or otherwise handled:

(i) You must have a sensor in rooms, buildings, deck areas, or low-laying deck areas not otherwise covered by paragraph (j)(2) of this section, where atmospheric concentrations of H_2S could reach 20 ppm or more. You must have at least one sensor per 400 square feet of deck area or fractional part of 400 square feet;

(ii) You must have a sensor in buildings where personnel have their living quarters;

(iii) You must have a sensor within 10 feet of each vessel, compressor, wellhead, manifold, or pump, which could release enough H_2S to result in atmospheric concentrations of 20 ppm at a distance of 10 feet from the component;

(iv) You may use one sensor to detect H_2S around multiple pieces of equipment, provided the sensor is located no more than 10 feet from each piece, except that you need to use at least two sensors to monitor compressors exceeding 50 horsepower;

(v) You do not need to have sensors near wells that are shut in at the master valve and sealed closed;

(vi) When you determine where to place sensors, you must consider:

(A) The location of system fittings, flanges, valves, and other devices subject to leaks to the atmosphere; and

(B) Design factors, such as the type of decking and the location of fire walls; and

(vii) The District Supervisor may require additional sensors or other monitoring capabilities, if warranted by site specific conditions.

(6) *How must I functionally test the H_2S Detectors?*

(i) Personnel trained to calibrate the particular H_2S detector equipment being used must test detectors by exposing them to a known concentration in the range of 10 to 30 ppm of H_2S.

(ii) If the results of any functional test are not within 2 ppm or 10 percent, whichever is greater, of the applied concentration, recalibrate the instrument.

(7) *How often must I test my detectors?*

(i) When conducting drilling, drill stem testing, well-completion, or well-workover operations in areas classified as H_2S present or H_2S unknown, test all detectors at least once every 24 hours. When drilling, begin functional testing before the bit is 1,500 feet (vertically) above the potential H_2S zone.

(ii) When conducting production operations, test all detectors at least every 14 days between tests.

(iii) If equipment requires calibration as a result of two consecutive functional tests, the District Supervisor may require that H_2S-detection and H_2S-monitoring equipment be functionally tested and calibrated more frequently.

(8) *What documentation must I keep?*

(i) You must maintain records of testing and calibrations (in the drilling or production operations report, as applicable) at the facility to show the present status and history of each device, including dates and details concerning:

(A) Installation;

(B) Removal;

(C) Inspection;

(D) Repairs;

(E) Adjustments; and

(F) Reinstallation.

(ii) Records must be available for inspection by MMS personnel.

(9) *What are the requirements for nearby vessels?* If vessels are stationed overnight alongside facilities in areas of H_2S present or H_2S unknown, you must equip vessels with an H_2S-detection system that activates audible and visual alarms when the concentration of H_2S in the atmosphere reaches 20 ppm. This requirement does not apply to vessels positioned upwind and at a safe distance from the facility in accordance with the positioning procedure described in the approved H_2S Contingency Plan.

(10) *What are the requirements for nearby facilities?* The District Supervisor may require you to equip nearby facilities with portable or fixed H_2S detector(s) and to test and calibrate those detectors. To invoke this requirement, the District Supervisor will consider dispersion modeling results from a possible release to determine if 20 ppm H_2S concentration levels could be exceeded at nearby facilities.

(11) *What must I do to protect against SO_2 if I burn gas containing H_2S?* You must:

(i) Monitor the SO_2 concentration in the air with portable or strategically placed fixed devices capable of detecting a minimum of 2 ppm of SO_2;

(ii) Take readings at least hourly and at any time personnel detect SO_2 odor or nasal irritation;

(iii) Implement the personnel protective measures specified in the H_2S Contingency Plan if the SO_2 concentration in the work area reaches 2 ppm; and

(iv) Calibrate devices every 3 months if you use fixed or portable electronic sensing devices to detect SO_2.

(12) *May I use alternative measures?* You may follow alternative measures instead of those in paragraph (j)(11) of this section if you propose and the Regional Supervisor approves the alternative measures.

(13) *What are the requirements for protective-breathing equipment?* In an area classified as H_2S present or H_2S unknown, you must:

(i) Provide all personnel, including contractors and visitors on a facility, with immediate access to self-contained pressure-demand-type respirators with hoseline capability and breathing time of at least 15 minutes.

(ii) Design, select, use, and maintain respirators to conform to ANSI Z88.2, American National Standard for Respiratory Protection.

(iii) Make available at least two voice-transmission devices, which can be used while wearing a respirator, for use by designated personnel.

(iv) Make spectacle kits available as needed.

(v) Store protective-breathing equipment in a location that is quickly and easily accessible to all personnel.

(vi) Label all breathing-air bottles as containing breathing-quality air for human use.

(vii) Ensure that vessels attendant to facilities carry appropriate protective-breathing equipment for each crew member. The District Supervisor may require additional protective-breathing equipment on certain vessels attendant to the facility.

(viii) During H_2S alerts, limit helicopter flights to and from facilities to the conditions specified in the H_2S Contingency Plan. During authorized flights, the flight crew and passengers must use pressure-demand-type respirators. You must train all members of flight crews in the use of the particular type(s) of respirator equipment made available.

(ix) As appropriate to the particular operation(s), (production, drilling, well-completion or well-workover operations, or any combination of them), provide a system of breathing-air manifolds, hoses, and masks at the facility and the briefing areas. You must provide a cascade air-bottle system for the breathing-air manifolds to refill individual protective-breathing apparatus bottles. The cascade air-bottle system may be recharged by a high-pressure compressor suitable for providing breathing-quality air, provided the compressor suction is located in an uncontaminated atmosphere.

(k) *Personnel safety equipment.*—(1) *What additional personnel-safety equipment do I need?* You must ensure that your facility has:

(i) Portable H_2S detectors capable of detecting a 10 ppm concentration of H_2S in the air available for use by all personnel;

(ii) Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas;

(iii) Chalkboards and/or note pads for communication purposes located on the rig floor, shale-shaker area, the cement-pump rooms, well-bay areas, production processing equipment area, gas compressor area, and pipeline-pump area;

(iv) Bull horns and flashing lights; and

(v) At least three resuscitators on manned facilities, and a number equal to the personnel on board, not to exceed three, on normally unmanned facilities, complete with face masks, oxygen bottles, and spare oxygen bottles.

(2) *What are the requirements for ventilation equipment?* You must:

(i) Use only explosion-proof ventilation devices;

(ii) Install ventilation devices in areas where H_2S or SO_2 may accumulate; and

(iii) Provide movable ventilation devices in work areas. The movable ventilation devices must be multidirectional and capable of dispersing H_2S or SO_2 vapors away from working personnel.

(3) *What other personnel safety equipment do I need?* You must have the following equipment readily available on each facility:

(i) A first-aid kit of appropriate size and content for the number of personnel on the facility; and

(ii) At least one litter or an equivalent device.

(l) *Do I need to notify MMS in the event of an H_2S release?* You must notify MMS without delay in the event of a gas release which results in a 15-minute time weighted average atmospheric concentration of H_2S of 20 ppm or more anywhere on the facility.

(m) *Do I need to use special drilling, completion and workover fluids or procedures?* When working in an area classified as H_2S present or H_2S unknown:

(1) You may use either water- or oil-base muds in accordance with § 250.40(b)(1).

(2) If you use water-base well-control fluids, and if ambient air sensors detect H_2S, you must immediately conduct either the Garrett-Gas-Train test or a comparable test for soluble sulfides to confirm the presence of H_2S.

(3) If the concentration detected by air sensors in over 20 ppm, personnel conducting the tests must don protective-breathing equipment conforming to paragraph (j)(13) of this section.

(4) You must maintain on the facility sufficient quantities of additives for the control of H_2S, well-control fluid pH, and corrosion equipment.

(i) *Scavengers.* You must have scavengers for control of H_2S available on the facility. When H_2S is detected, you must add scavengers as needed. You must suspend drilling until the scavenger is circulated throughout the system.

(ii) *Control pH.* You must add additives for the control of pH to water-base well-control fluids in sufficient quantities to maintain pH of at least 10.0.

(iii) *Corrosion inhibitors.* You must add additives to the well-control fluid system as needed for the control of corrosion.

(5) You must degas well-control fluids containing H_2S at the optimum location for the particular facility. You must collect the gases removed and burn them in a closed flare system conforming to paragraph (q)(6) of this section.

(n) *What must I do in the event of a kick?* In the event of a kick, you must use one of the following alternatives to dispose of the well-influx fluids giving consideration to personnel safety, possible environmental damage, and possible facility well-equipment damage:

(1) Contain the well-fluid influx by shutting in the well and pumping the fluids back into the formation.

(2) Control the kick by using appropriate well-control techniques to prevent formation fracturing in an open hole within the pressure limits of the well equipment (drill pipe, work string, casing, wellhead, BOP system, and related equipment). The disposal of H_2S and other gases must be through pressurized or atmospheric mud-separator equipment depending on volume, pressure and concentration of H_2S. The equipment must be designed to recover well-control fluids and burn the gases separated from the well-control fluid. The well-control fluid must be treated to neutralize H_2S and restore and maintain the proper quality.

(o) *Well testing in a zone known to contain H_2S.* When testing a well in a zone with H_2S present, you must do all of the following:

(1) Before starting a well test, conduct safety meetings for all personnel who will be on the facility during the test. At the meetings, emphasize the use of protective-breathing equipment, first-aid procedures, and the Contingency Plan. Only competent personnel who are trained and are knowledgeable of the hazardous effects of H_2S must be engaged in these tests.

(2) Perform well testing with the minimum number of personnel in the immediate vicinity of the rig floor and with the appropriate test equipment to safely and adequately perform the test. During the test, you must continuously monitor H_2S levels.

(3) Not burn produced gases except through a flare which meets the requirements of paragraph (q)(6) of this section. Before flaring gas containing H_2S, you must activate SO_2 monitoring equipment in accordance with paragraph (j)(11) of this section. If you detect SO_2 in excess of 2 ppm, you must implement the personnel protective measures in your H_2S Contingency Plan, required by paragraph (f)(13)(iv) of this section. You must also follow the requirements of § 250.175. You must pipe gases from stored test fluids into the flare outlet and burn them.

(4) Use downhole test tools and wellhead equipment suitable for H_2S service.

(5) Use tubulars suitable for H_2S service. You must not use drill pipe for well testing without the prior approval of the District Supervisor. Water cushions must be thoroughly inhibited in order to prevent H_2S attack on metals. You must flush the test string fluid treated for this purpose after completion of the test.

(6) Use surface test units and related equipment that is designed for H_2S service.

(p) *Metallurgical properties of equipment.* When operating in a zone with H_2S present, you must use equipment that is constructed of materials with metallurgical properties that resist or prevent sulfide stress cracking (also known as hydrogen embrittlement, stress corrosion cracking, or H_2S embrittlement), chloride-stress cracking, hydrogen-induced cracking, and other failure modes. You must do all of the following:

(1) Use tubulars and other equipment, casing, tubing, drill pipe, couplings, flanges, and related equipment that is designed for H_2S service.

(2) Use BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H_2S-bearing fluids that conform to NACE Standard MR.01–75–96.

(3) Use temporary downhole well-security devices such as retrievable packers and bridge plugs that are designed for H_2S service.

(4) When producing in zones bearing H_2S, use equipment constructed of materials capable of resisting or preventing sulfide stress cracking.

(5) Keep the use of welding to a minimum during the installation or modification of a production facility. Welding must be done in a manner that ensures resistance to sulfide stress cracking.

(q) *General requirements when operating in an H_2S zone*—(1) *Coring operations.* When you conduct coring operations in H_2S-bearing zones, all personnel in the working area must wear protective-breathing equipment at least 10 stands in advance of retrieving the core barrel. Cores to be transported must be sealed and marked for the presence of H_2S.

(2) *Logging operations.* You must treat and condition well-control fluid in use for logging operations to minimize the effects of H_2S on the logging equipment.

(3) *Stripping operations.* Personnel must monitor displaced well-control fluid returns and wear protective-breathing equipment in the working area when the atmospheric concentration of H_2S reaches 20 ppm or if the well is under pressure.

(4) *Gas-cut well-control fluid or well kick from H_2S-bearing zone.* If you decide to circulate out a kick, personnel in the working area during bottoms-up and extended-kill operations must wear protective-breathing equipment.

(5) *Drill- and workover-string design and precautions.* Drill- and workover-strings must be designed consistent with the anticipated depth, conditions of the hole, and reservoir environment to be encountered. You must minimize exposure of the drill- or workover-string to high stresses as much as practical and consistent with well conditions. Proper handling techniques must be taken to minimize notching and stress concentrations. Precautions must be taken to minimize stresses caused by doglegs, improper stiffness ratios, improper torque, whip, abrasive wear on tool joints, and joint imbalance.

(6) *Flare system.* The flare outlet must be of a diameter that allows easy nonrestricted flow of gas. You must locate flare line outlets on the downside of the facility and as far from the facility as is feasible, taking into account the prevailing wind directions, the wake

effects caused by the facility and adjacent structure(s), and the height of all such facilities and structures. You must equip the flare outlet with an automatic ignition system including a pilot-light gas source or an equivalent system. You must have alternate methods for igniting the flare. You must pipe to the flare system used for H_2S all vents from production process equipment, tanks, relief valves, burst plates, and similar devices.

(7) *Corrosion mitigation.* You must use effective means of monitoring and controlling corrosion caused by acid gases (H_2S and CO_2) in both the downhole and surface portions of a production system. You must take specific corrosion monitoring and mitigating measures in areas of unusually severe corrosion where accumulation of water and/or higher concentration of H_2S exists.

(8) *Wireline lubricators.* Lubricators which may be exposed to fluids containing H_2S must be of H_2S-resistant materials.

(9) *Fuel and/or instrument gas.* You must not use gas containing H_2S for instrument gas. You must not use gas containing H_2S for fuel gas without the prior approval of the District Supervisor.

(10) *Sensing lines and devices.* Metals used for sensing line and safety-control devices which are necessarily exposed to H_2S-bearing fluids must be constructed of H_2S-corrosion resistant materials or coated so as to resist H_2S corrosion.

(11) *Elastomer seals.* You must use H_2S-resistant materials for all seals which may be exposed to fluids containing H_2S.

(12) *Water disposal.* If you dispose of produced water by means other than subsurface injection, you must submit to the District Supervisor an analysis of the anticipated H_2S content of the water at the final treatment vessel and at the discharge point. The District Supervisor may require that the water be treated for removal of H_2S. The District Supervisor may require the submittal of an updated analysis if the water disposal rate or the potential H_2S content increases.

(13) *Deck drains.* You must equip open deck drains with traps or similar devices to prevent the escape of H_2S gas into the atmosphere.

(14) *Sealed voids.* You must take precautions to eliminate sealed spaces in piping designs (e.g., slip-on flanges, reinforcing pads) which can be invaded by atomic hydrogen when H_2S is present.

[62 FR 3795, Jan. 27, 1997]

Subpart E—Oil and Gas Well-Completion Operations

§ 250.70 General requirements.

Well-completion operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment.

§ 250.71 Definition.

When used in this subpart, the following term shall have the meaning given below:

Well-completion operations means the work conducted to establish the production of a well after the production-casing string has been set, cemented, and pressure-tested.

§ 250.72 Equipment movement.

The movement of well-completion rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-completion rigs and related equipment, unless otherwise approved by the District Supervisor. A closed surface-controlled subsurface safety valve of the pump-through type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out of operation. The well from which the rig or related equipment is to be moved shall also be equipped with a back-pressure valve

prior to removing the blowout preventer (BOP) system and installing the tree.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990]

§250.73 Emergency shutdown system.

When well-completion operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station.

§250.74 Hydrogen sulfide.

When a well-completion operation is conducted in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown (as defined in §250.67 of this part), the lessee shall take appropriate precautions to protect life and property on the platform or completion unit, including, but not limited to operations such as blowing the well down, dismantling wellhead equipment and flow lines, circulating the well, swabbing, and pulling tubing, pumps, and packers. The lessee shall comply with the requirements in §250.67 of this part as well as the appropriate requirements of this subpart.

§250.75 Subsea completions.

No subsea well completion shall be commenced until the lessee obtains written approval from the District Supervisor in accordance with §250.83 of this part. That approval shall be based upon a case-by-case determination that the proposed equipment and procedures will adequately control the well and permit safe production operations.

§250.76 Crew instructions.

Prior to engaging in well-completion operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by MMS representatives.

§250.77 Welding and burning practices and procedures.

All welding, burning, and hot tapping activities involved in well-completion operations shall be conducted in accordance with the requirements in §250.52 of this part.

§250.78 Electrical requirements.

All electrical equipment and systems involved in well-completion operations shall be designed, installed, equipped, protected, operated, and maintained in accordance with the requirements in §250.53 of this part.

§250.79 Well-completion structures on fixed platforms.

Derricks, masts, substructures, and related equipment shall be selected, designed, installed, used, and maintained so as to be adequate for the potential loads and conditions of loading that may be encountered during the proposed operations. Prior to moving a well-completion rig or equipment onto a platform, the lessee shall determine the structural capability of the platform to safely support the equipment and proposed operations, taking into consideration the corrosion protection, age of platform, and previous stresses to the platform.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989]

§250.80 Diesel engine air intakes.

No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic-shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic-shutdown devices.

§250.81 Traveling-block safety device.

After May 31, 1989, all units being used for well-completion operations which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking

the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.82 Field well-completion rules.

When geological and engineering information available in a field enables the District Supervisor to determine specific operating requirements, field well-completion rules may be established on the District Supervisor's initiative or in response to a request from a lessee. Such rules may modify the specific requirements of this subpart. After field well-completion rules have been established, well-completion operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field well-completion rules may be amended or canceled for cause at any time upon the initiative of the District Supervisor or upon the request of a lessee.

§ 250.83 Approval and reporting of well-completion operations.

(a) No well-completion operation shall begin until the lessee receives written approval from the District Supervisor. If completion is planned and the data are available at the time the Application for Permit to Drill, Form MMS–123 (see § 250.64 of this part), is submitted, approval for a well completion may be requested on that form. If the completion has not been approved or if the completion objective or plans have significantly changed, approval for such operations shall be requested on Form MMS–124, Sundry Notices and Reports on Wells.

(b) The following information shall be submitted with Form MMS–124 (or with Form MMS–123):

(1) A brief description of the well-completion procedures to be followed, a statement of the expected surface pressure, and type and weight of completion fluids;

(2) A schematic drawing of the well showing the proposed producing zone(s) and the subsurface well-completion equipment to be used;

(3) For multiple completions, a partial electric log showing the zones proposed for completion, if logs have not been previously submitted; and

(4) When the well-completion is in a zone known to contain H_2S or a zone where the presence of H_2S is unknown, information pursuant to § 250.67 of this part.

(c) Within 30 days after completion, Form MMS–125, Well Summary Report, including a schematic of the tubing and subsurface equipment, shall be submitted to the District Supervisor.

(d) Public information copies of Form MMS–125 shall be submitted in accordance with § 250.17.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.84 Well-control fluids, equipment, and operations.

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-completion operations and shall not be left unattended at any time unless the well is shut in and secured.

(b) The following well-control-fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP;

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

(c) When coming out of the hole with drill pipe, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or

electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.

§ 250.85 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and BOP system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS–124 or Form MMS–123, as appropriate, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-completion operations shall include the following:

(1) Three preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, one preventer equipped with pipe rams, and one preventer equipped with blind or blind-shear rams.

(2) Four preventers, when the expected surface pressure is 5,000 psi or greater, or for multiple tubing strings consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind or blind-shear rams. When dual tubing strings are being handled simultaneously, dual pipe rams shall be installed on one of the pipe-ram preventers.

(3) When tapered drill string is used, the minimum BOP system shall include either of the following:

(i) Four preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, two sets of pipe rams, one capable of sealing around the larger size drill string and one capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for the two sets of pipe rams), and one preventer equipped with blind or blind shear rams; or

(ii) Five preventers, when the expected surface pressure is 5,000 psi or greater, consisting of an annular preventer, two sets of pipe rams capable of sealing around the larger size drill string, one set of pipe rams capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for one set of pipe rams capable of sealing around the larger size drill string and the set of pipe rams capable of sealing around the smaller size drill string), and a preventer equipped with blind or blind-shears rams.

(c) The BOP systems for well completions shall be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed.

(3) Locking devices for the pipe-ram preventers.

(4) At least one remote BOP-control station and one BOP-control station on the rig floor.

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided that two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating

at least equivalent to the ram preventers.

(d) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993]

§ 250.86 Blowout preventer system testing, records, and drills.

(a) Prior to conducting high-pressure tests, all BOP system components shall be successfully tested to a low pressure of 200 psi to 300 psi. Ram-type BOP's, related control equipment, including the choke and kill manifolds, and safety valves shall be successfully tested to the rated working pressure of the BOP equipment or as otherwise approved by the District Supervisor. Variable bore rams shall be pressure-tested against all sizes of drill pipe in the well excluding drill collars. Surface BOP systems shall be pressure-tested with water. The annular BOP shall be successfully tested at 70 percent of its rated working pressure or as otherwise approved by the District Supervisor. Each valve in the choke and kill manifolds shall be successfully, sequentially pressure tested to the ram-type BOP test pressure.

(b) The BOP systems shall be tested at the following times:

(1) When installed.

(2) At least every 7 days, alternating between control stations and at staggered intervals to allow each crew to operate the equipment. If either control system is not functional, further operations shall be suspended until the nonfunctional system is operable. To test every 7 days is not required for blind or blind-shear rams. The blind or blind-shear rams shall be tested at least once every 30 days during operations. A longer period between blowout preventer tests is allowed when there is a stuck pipe or pressure-control operation and remedial efforts are being performed. The tests shall be conducted as soon as possible and before normal operations resume. The reason for postponing testing shall be entered into the operations log.

(3) Following repairs that require disconnecting a pressure seal in the assembly, the affected seal will be pressure tested.

(c) All personnel engaged in well-completion operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test interval for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(e) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system, system components, and marine risers shall be recorded in the operations log. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the operations log. For a subsea system, the pod used during the test shall be identified in the operations log.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the operations log.

(4) Documentation required to be entered in the operations log may instead be referenced in the operations log. All records including pressure charts, operations log, and referenced documents pertaining to BOP tests, actuations, and inspections shall be available for MMS review at the facility for the duration of the well-completion activity.

Following completion of the well-completion activity, all such records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 55 FR 47752, Nov. 15, 1990; 56 FR 1915, Jan. 18, 1991]

§ 250.87 Tubing and wellhead equipment.

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure-tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Supervisor.

(c) When the tree is installed, the wellhead shall be equipped so that all annuli can be monitored for sustained pressure. If sustained casing pressure is observed on a well, the lessee shall immediately notify the District Supervisor.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut–in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. New wells completed as flowing or gas-lift wells shall be equipped with a minimum of one master valve and one surface safety valve, installed above the master valve, in the vertical run of the tree.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.121 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47753 Nov. 15, 1990]

Subpart F—Oil and Gas Well-Workover Operations

§ 250.90 General requirements.

Well-workover operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment.

§ 250.91 Definitions.

When used in this subpart, the following terms shall have the meanings given below:

Routine operations mean any of the following operations conducted on a well with the tree installed:

(a) Cutting paraffin;

(b) Removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations;

(c) Bailing sand;

(d) Pressure surveys;

(e) Swabbing;

(f) Scale or corrosion treatment;

(g) Caliper and gauge surveys;

(h) Corrosion inhibitor treatment;

(i) Removing or replacing subsurface pumps;

(j) Through-tubing logging (diagnostics);

(k) Wireline fishing; and

(l) Setting and retrieving other subsurface flow-control devices.

Workover operations mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

§ 250.92 Equipment movement.

The movement of well-workover rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-workover rigs and related equipment unless otherwise approved by the District Supervisor. A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation. The

well to which a well-workover rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the tree and installing and testing the blowout-preventer (BOP) system. The well from which a well-workover rig or related equipment is to be moved shall also be equipped with a back pressure valve prior to removing the BOP system and installing the tree. Coiled tubing units, snubbing units, or wireline units may be moved onto a platform without shutting in wells.

§ 250.93 Emergency shutdown system.

When well-workover operations are conducted on a well with the tree removed, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station, except when there is no other hydrocarbon-producing well or other hydrocarbon flow on the platform.

§ 250.94 Hydrogen sulfide.

When a well-workover operation is conducted in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown (as defined in § 250.67 of this part), the lessee shall take appropriate precautions to protect life and property on the platform or rig, including but not limited to operations such as blowing the well down, dismantling wellhead equipment and flow lines, circulating the well, swabbing, and pulling tubing, pumps and packers. The lessee shall comply with the requirements in § 250.67 of this part as well as the appropriate requirements of this subpart.

§ 250.95 Subsea workovers.

No subsea well-workover operation including routine operations shall be commenced until the lessee obtains written approval from the District Supervisor in accordance with § 250.103 of this part. That approval shall be based upon a case-by-case determination that the proposed equipment and procedures will maintain adequate control of the well and permit continued safe production operations.

§ 250.96 Crew instructions.

Prior to engaging in well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by a Minerals Management Service representative.

§ 250.97 Welding and burning practices and procedures.

All welding, burning, and hot-tapping activities involved in well-workover operations shall be conducted in accordance with the requirements of § 250.52 of this part.

§ 250.98 Electrical requirements.

All electrical equipment and systems involved in well-workover operations shall be designed, installed, equipped, protected, operated, and maintained in accordance with the requirements in § 250.53 of this part.

§ 250.99 Well-workover structures on fixed platforms.

Derricks, masts, substructures, and related equipment shall be selected, designed, installed, used, and maintained so as to be adequate for the potential loads and conditions of loading that may be encountered during the operations proposed. Prior to moving a well-workover rig or well-servicing equipment onto a platform, the lessee shall determine the structural capability of the platform to safely support the equipment and proposed operations, taking into consideration the corrosion protection, age of the platform, and previous stresses to the platform.

§ 250.100 Diesel engine air intakes.

No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be

equipped with automatic shutdown devices.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989]

§ 250.101 Traveling-block safety device.

After May 31, 1989, all units being used for well-workover operations which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.102 Field well-workover rules.

When geological and engineering information available in a field enables the District Supervisor to determine specific operating requirements, field well-workover rules may be established on the District Supervisor's initiative or in response to a request from a lessee. Such rules may modify the specific requirements of this subpart. After field well-workover rules have been established, well-workover operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field well-workover rules may be amended or canceled for cause at any time upon the initiative of the District Supervisor or upon the request of a lessee.

§ 250.103 Approval and reporting for well-workover operations.

(a) No well-workover operation except routine ones, as defined in § 250.91 of this part, shall begin until the lessee receives written approval from the District Supervisor. Approval for such operations shall be requested on Form MMS–124, Sundry Notices and Reports on Wells.

(b) The following information shall be submitted with Form MMS–124:

(1) A brief description of the well-workover procedures to be followed, a statement of the expected surface pressure, and type and weight of workover fluids;

(2) When changes in existing subsurface equipment are proposed, a schematic drawing of the well showing the zone proposed for workover and the workover equipment to be used; and

(3) Where the well-workover is in a zone known to contain H_2S or a zone where the presence of H_2S is unknown, information pursuant to § 250.67 of this part.

(c) The following additional information shall be submitted with Form MMS–124 if completing to a new zone is proposed:

(1) Reason for abandonment of present producing zone including supportive well test data, and

(2) A statement of anticipated or known pressure data for the new zone.

(d) Within 30 days after completing the well-workover operation, except routine operations, Form MMS–124, Sundry Notices and Reports on Wells, shall be submitted to the District Supervisor, showing the work as performed. In the case of a well-workover operation resulting in the initial recompletion of a well into a new zone, a Form MMS–125, Well Summary Report, shall be submitted to the District Supervisor and shall include a new schematic of the tubing subsurface equipment if any subsurface equipment has been changed.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.104 Well-control fluids, equipment, and operations.

The following requirements apply during all well-workover operations with the tree removed:

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-workover operations and shall not be left unattended at anytime unless the well is shut in and secured.

(b) When coming out of the hole with drill pipe or a workover string, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe or workover string, whichever gives a lower decrease in hydrostatic pressure.

The number of stands of drill pipe or workover string and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hold shall be utilized.

(c) The following well-control-fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP;

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

§ 250.105 Blowout prevention equipment.

(a) The BOP system, system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS–124, requesting approval of the well-workover operation, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-workover operations with the tree removed shall include of the following:

(1) Three preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, one preventer equipped with pipe rams, and one preventer equipped with blind or blind-shear rams.

(2) Four preventers, when the expected surface pressure is 5,000 psi or greater, or for multiple tubing strings consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind or blind-shear rams. When dual tubing strings are being handled simultaneously, dual pipe rams shall be installed on one of the pipe-ram preventers.

(3) When a tapered drill string is used, the minimum BOP system shall include either of the following:

(i) Four preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, two sets of pipe rams, one capable of sealing around the larger size drill string, and one capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for the two sets of pipe rams), and one preventer equipped with blind or blind-shear rams; or

(ii) Five preventers, when the expected surface pressure is 5,000 psi or greater, consisting of an annular preventer, two sets of pipe rams capable of sealing around the larger size drill string, one set of pipe rams capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for one set of pipe rams capable of sealing around the larger size drill string and the set of pipe rams capable of sealing around the smaller size drill string), and a preventer equipped with blind or blind-shear rams.

(c) The BOP systems for well-workover operations with the tree removed shall be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost;

(2) A secondary power source, independent from the primary power

source, with sufficient capacity to close all BOP system components and hold them closed;

(3) Locking devices for the pipe-ram preventers;

(4) At least one remote BOP-control station and one BOP-control station on the rig floor; and

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke-line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating at least equivalent to the ram preventers.

(d) The minimum BOP-system components for well-workover operations with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually ¾ inch to 1¼ inch) as a work string, i.e., small-tubing operations, shall include the following:

(1) Two sets of pipe rams, and

(2) One set of blind rams.

(e) The minimum BOP-system components for well-workover operations with the tree in place and performed by manipulating spooled, nonjointed pipe through the wellhead, i.e., coiled-tubing operations, shall include the following:

(1) One set of pipe rams hydraulically operated,

(2) One two-way slip assembly hydraulically operated,

(3) One pipe-cutter assembly hydraulically operated,

(4) One set of blind rams hydraulically operated,

(5) One pipe-stripper assembly, and

(6) One spool with side outlets.

(f) The minimum BOP-system components for well-workover operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, i.e., snubbing operations, shall include the following:

(1) One set of pipe rams hydraulically operated, and

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool.

(g) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-workover operations when the tree is removed or during well-workover operations with the tree installed and using small tubing as the work string. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string. The full-opening safety valve is not required for coiled tubing or snubbing operations.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993]

§ 250.106 Blowout preventer system testing, records, and drills.

(a) Prior to conducting high-pressure tests, all BOP system components shall be successfully tested to a low pressure of 200 to 300 psi. Ram-type BOP's, related control equipment, including the choke and kill manifolds, and safety valves shall be successfully tested to the rated working pressure of the BOP equipment or as otherwise approved by the District Supervisor. Variable bore rams shall be pressure-tested against all sizes of drill pipe in the well excluding drill collars. Surface BOP systems shall be pressure tested with water. The annular-type BOP shall be successfullly tested at 70 percent of its rated working pressure or as otherwise approved by the District Supervisor. Each valve in the choke and kill manifolds shall be successfully, sequentially pressure tested to the ram-type BOP test pressure.

(b) The BOP systems shall be tested at the following times:

(1) When installed;

(2) At least every 7 days, alternating between control stations and at staggered intervals to allow each crew to operate the equipment. If either control system is not functional, further operations shall be suspended until the nonfunctional, system is operable. The

test every 7 days is not required for blind or blind-shear rams. The blind or blind-shear rams shall be tested at least once every 30 days during operation. A longer period between blowout preventer tests is allowed when there is a stuck pipe or pressure-control operation and remedial efforts are being performed. The tests shall be conducted as soon as possible and before normal operations resume. The reason for postponing testing shall be entered into the operations log.

(3) Following repairs that require disconnecting a pressure seal in the assembly, the affected seal will be pressure tested.

(c) All personnel engaged in well-workover operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test interval for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(e) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system, system components, and marine risers shall be recorded in the operations log. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the operations log. For a subsea system, the pod used during the test shall be identified in the operations log.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the operations log.

(4) Documentation required to be entered in the operation log may instead be referenced in the operations log. All records including pressure charts, operations log, and referenced documents pertaining to BOP tests, actuations, and inspections, shall be available for MMS review at the facility for the duration of well-workover activity. Following completion of the well-workover actity, all such records shall be retained for a period of 2 years at the facility, at the lessee's filed office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 56 FR 1915, Jan. 18, 1991]

§ 250.107 Tubing and wellhead equipment.

The lessee shall comply with the following requirements during well-workover operations with the tree removed:

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Supervisor.

(c) When reinstalling the tree, the wellhead shall be equiped so that all annuli can be monitored for sustained pressure. If sustained casing pressure is observed on a well, the lessee shall immediately notify the District Supervisor.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. The tree shall be equipped with a minimum of one master valve and one surface safety valve in the vertical run of the tree when it is reinstalled.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.121 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 55 FR 47753, Nov. 15, 1990]

§ 250.108 Wireline operations.

The lessee shall comply with the following requirements during routine, as defined in § 250.91 of this part, and nonroutine wireline workover operations:

(a) Wireline operations shall be conducted so as to minimize leakage of well fluids. Any leakage that does occur shall be contained to prevent pollution.

(b) All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at least one wireline valve.

(c) When the lubricator is initially installed on the well, it shall be successfully pressure tested to the expected shut-in surface pressure.

Subpart G—Abandonment of Wells

§ 250.110 General requirements.

(a) The lessee shall abandon all wells in a manner to assure downhole isolation of hydrocarbon zones, protection of freshwater aquifers, clearance of sites so as to avoid conflict with other uses of the Outer Continental Shelf (OCS), and prevention of migration of formation fluids within the wellbore or to the seafloor. Any well which is no longer used or useful for lease operations shall be plugged and abandoned in accordance with the provisions of this subpart. However, no production well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the District Supervisor. No well shall be plugged if the plugging operations would jeopardize safe and economic operations of nearby wells, unless the well poses a hazard to safety or the environment.

(b) Lessees must plug and abandon all well bores, remove all platforms or other facilities, and clear the ocean of all obstructions to other users. This obligation:

(1) Accrues to the lessee when the well is drilled, the platform or other facility is installed, or the obstruction is created; and

(2) Is the joint and several responsibility of all lessees and owners of operating rights under the lease at the time the obligation accrues, and of each future lessee or owner of operating rights, until the obligation is satisfied under the requirements of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 62 FR 27955, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27955, May 22, 1997, § 250.110 was amended by designating the existing text as paragraph (a) and adding a new paragraph (b), effective Aug. 20, 1997.

§ 250.111 Approvals.

The lessee shall not commence abandonment operations without prior approval of the District Supervisor. The lessee shall submit a request on Form MMS–124, Sundry Notices and Reports on Wells, for approval to abandon a well and a subsequent report of abandonment within 30 days from completion of the work in accordance with the following:

(a) *Notice of Intent to Abandon Well.* A request for approval to abandon a well shall contain the reason for abandonment including supportive well logs and test data, a description and schematic of proposed work including depths, type, location, length of plugs, the plans for mudding, cementing, shooting, testing, casing removal, and other pertinent information.

(b) *Subsequent report of abandonment.* The subsequent report of abandonment shall include a description of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in the plugging, and all information listed in paragraph (a) of this section with a revised schematic. If an attempt was made to cut and pull any casing string, the subsequent report shall include a description of the methods used, size of casing removed, depth of the casing removal point, and the

amount of the casing removed from the well.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.112 Permanent abandonment.

(a) *Isolation of zones in open hole.* In uncased portions of wells, cement plugs shall be set to extend from a minimum of 100 feet below the bottom to 100 feet above the top of any oil, gas, or freshwater zones to isolate fluids in the strata in which they are found and to prevent them from escaping into other strata or to the seafloor. The placement of additional cement plugs to prevent the migration of formation fluids in the wellbore may be required by the District Supervisor.

(b) *Isolation of open hole.* Where there is an open hole below the casing, a cement plug shall be placed in the deepest casing by the displacement method and shall extend a minimum of 100 feet above and 100 feet below the casing shoe. In lieu of setting a cement plug across the casing shoe, the following methods are acceptable:

(1) A cement retainer and a cement plug shall be set. The cement retainer shall have effective back-pressure control and shall be set not less than 50 feet and not more than 100 feet above the casing shoe. The cement plug shall extend at least 100 feet below the casing shoe and at least 50 feet above the retainer.

(2) If lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed within the first 150 feet above the casing shoe with a minimum of 50 feet of cement on top of the bridge plug. This bridge plug shall be tested in accordance with paragraph (g) of this section.

(c) *Plugging or isolating perforated intervals.* A cement plug shall be set by the displacement method opposite all perforations which have not been squeezed with cement. The cement plug shall extend a minimum of 100 feet above the perforated interval and either 100 feet below the perforated interval or down to a casing plug, whichever is the lesser. In lieu of setting a cement plug by the displacement method, the following methods are acceptable, provided the perforations are isolated from the hole below:

(1) A cement retainer and a cement plug shall be set. The cement retainer shall have effective back-pressure control and shall be set not less than 50 feet and not more than 100 feet above the top of the perforated interval. The cement plug shall extend at least 100 feet below the bottom of the perforated interval with 50 feet placed above the retainer.

(2) A permanent-type bridge plug shall be set within the first 150 feet above the top of the perforated interval with at least 50 feet of cement on top of the bridge plug.

(3) A cement plug which is at least 200 feet long shall be set by the displacement method with the bottom of the plug within the first 100 feet above the top of the perforated interval.

(d) *Plugging of casing stubs.* If casing is cut and recovered leaving a stub, the stub shall be plugged in accordance with one of the following methods:

(1) A stub terminating inside a casing string shall be plugged with a cement plug extending at least 100 feet above and 100 feet below the stub. In lieu of setting a cement plug across the stub, the following methods are acceptable:

(i) A cement retainer or a permanent-type bridge plug shall be set not less than 50 feet above the stub and capped with at least 50 feet of cement, or

(ii) A cement plug which is at least 200 feet long shall be set with the bottom of the plug within 100 feet above the stub.

(2) If the stub is below the next larger string, plugging shall be accomplished as required to isolate zones or to isolate an open hole as described in paragraphs (a) and (b) of this section.

(e) *Plugging of annular space.* Any annular space communicating with any open hole and extending to the mud line shall be plugged with at least 200 feet of cement.

(f) *Surface plug.* A cement plug which is at least 150 feet in length shall be set with the top of the plug within the first 150 feet below the mud line. The plug shall be placed in the smallest string of casing which extends to the mud line.

(g) *Testing of plugs.* The setting and location of the first plug below the surface plug shall be verified by one of the following methods:

(1) The lessee shall place a minimum pipe weight of 15,000 pounds on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer is not required to be tested.

(2) The lessee shall test the plug with a minimum pump pressure of 1,000 pounds per square inch with a result of no more than a 10-percent pressure drop during a 15-minute period.

(h) *Fluid left in hole.* Each of the respective intervals of the hole between the various plugs shall be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure in the intervals between the plugs at time of abandonment.

(i) *Clearance of location.* All wellheads, casings, pilings, and other obstructions shall be removed to a depth of at least 15 feet below the mud line or to a depth approved by the District Supervisor. The lessee shall verify that the location has been cleared of all obstructions in accordance with § 250.114 of this part. The requirement for removing subsea wellheads or other obstructions and for verifying location clearance may be reduced or eliminated when, in the opinion of the District Supervisor, the wellheads or other obstructions would not constitute a hazard to other users of the seafloor or other legitimate uses of the area.

(j) *Requirements for permafrost areas.* The following requirements shall be implemented for permafrost areas:

(1) Fluid left in the hole adjacent to permafrost zones shall have a freezing point below the temperature of the permafrost and shall be treated to inhibit corrosion.

(2) The cement used for cement plugs placed across permafrost zones shall be designed to set before freezing and to have a low heat of hydration.

§ 250.113 Temporary abandonment.

(a) Any drilling well which is to be temporarily abandoned shall meet the requirements for permanent abandonment (except for the provisions in §§ 250.112 (f) and (i), and 250.114) and the following:

(1) A bridge plug or a cement plug at least 100 feet in length shall be set at the base of the deepest casing string unless the casing string has been cemented and has not been drilled out. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole.

(2) A retrievable or a permanent-type bridge plug or a cement plug at least 100 feet in length, shall be set in the casing within the first 200 feet below the mud line.

(b) Subsea wellheads, casing stubs, or other obstructions above the seafloor remaining after temporary abandonment will be protected in such a manner as to allow commercial fisheries gear to pass over the structure without damage to the structure or fishing gear. Depending on water depth, nature and height of obstruction above the seafloor, and the types and periods of fishing activity in the area, the District Supervisor may waive this requirement.

(c) In order to maintain the temporarily abandoned status of a well, the lessee shall provide, within 1 year of the original temporary abandonment and at successive 1-year intervals thereafter, an annual report describing plans for reentry to complete or permanently abandon the well.

(d) Identification and reporting of subsea wellheads, casing stubs, or other obstructions extending above the mud line will be accomplished in accordance with the requirements of the U.S. Coast Guard.

§ 250.114 Site clearance verification.

(a) The lessees shall verify site clearance after abandonment by one or more of the following methods as approved by the District Supervisor:

(1) Drag a trawl in two directions across the location,

(2) Perform a diver search around the wellbore,

(3) Scan across the location with a side-scan or on-bottom scanning sonar, or

(4) Use other methods based on particular site conditions.

(b) Certification that the area was cleared of all obstructions, the date the

work was performed, the extent of the area searched around the location, and the search method utilized shall be submitted on Form MMS–124.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

Subpart H—Oil and Gas Production Safety Systems

§ 250.120 General requirements.

Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety and protection of the human, marine, and coastal environments. Production safety systems operated in subfreezing climates shall utilize equipment and procedures selected with consideration of floating ice, icing, and other extreme environmental conditions that may occur in the area. Production shall not commence until the production safety system has been approved and a preproduction inspection has been requested by the lessee.

§ 250.121 Subsurface safety devices.

(a) *General.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after application and justification, the well is determined by the District Supervisor to be incapable of natural flowing. These devices may consist of a surface-controlled subsurface safety valve (SSSV), a subsurface-controlled SSSV, an injection valve, a tubing plug, or a tubing/annular subsurface safety device, and any associated safety valve lock or landing nipple.

(b) *Specifications for SSSV's.* Surface-controlled and subsurface-controlled SSSV's and safety valve locks and landing nipples installed in the OCS shall conform to the requirements in § 250.126 of this part.

(c) *Surface-controlled SSSV's.* All tubing installations open to a hydrocarbon-bearing zone which is capable of natural flow shall be equipped with a surface-controlled SSSV, except as specified in paragraphs (d), (f), and (g) of this section. The surface controls may be located on the site or a remote location. Wells not previously equipped with a surface-controlled SSSV and wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV in accordance with paragraph (d)(2) of this section shall be equipped with a surface-controlled SSSV when the tubing is first removed and reinstalled.

(d) *Subsurface-controlled SSSV's.* Wells may be equipped with subsurface-controlled SSSV's in lieu of a surface-controlled SSSV provided the lessee demonstrates to the District Supervisor's satisfaction that one of the following criteria are met:

(1) Wells not previously equipped with surface-controlled SSSV's shall be so equipped when the tubing is first removed and reinstalled,

(2) The subsurface-controlled SSSV is installed in wells completed from a single-well or multiwell satellite caisson or seafloor completions, or

(3) The subsurface-controlled SSSV is installed in wells with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing.

(e) *Design, installation, and operation of SSSV's.* The SSSV's shall be designed, installed, operated, and maintained to ensure reliable operation.

(1) The device shall be installed at a depth of 100 feet or more below the seafloor within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffins, an alternate setting depth of the subsurface safety device may be approved by the District Supervisor.

(2) Until a subsurface safety device is installed, the well shall be attended in the immediate vicinity so that emergency actions may be taken while the well is open to flow. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

(3) The well shall not be open to flow while the subsurface safety device is removed, except when flowing of the well is necessary for a particular operation such as cutting paraffin, bailing sand, or similar operations.

(4) All SSSV's shall be inspected, installed, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems.

(f) *Subsurface safety devices in shut-in wells.* New completions (perforated but not placed on production) and completions shut in for a period of 6 months shall be equipped with either (1) a pump-through-type tubing plug; (2) a surface-controlled SSSV, provided the surface control has been rendered inoperative; or (3) an injection valve capable of preventing backflow. The setting depth of the subsurface safety device shall be approved by the District Supervisor on a case-by-case basis, when warranted by conditions such as permafrost, unstable bottom conditions, hydrate formations, and paraffins.

(g) *Subsurface safety devices in injection wells.* A surface-controlled SSSV or an injection valve capable of preventing backflow shall be installed in all injection wells. This requirement is not applicable if the District Supervisor concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually.

(h) *Temporary removal for routine operations.* (1) Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Form MMS–124, Sundry Notices and Reports on Wells, in § 250.91 of this part for a period not to exceed 15 days.

(2) The well shall be identified by a sign on the wellhead stating that the subsurface safety device has been removed. The removal of the subsurface safety device shall be noted in the records as required in § 250.124(b) of this part. If the master valve is open, a trained person shall be in the immediate vicinity of the well to attend the well so that emergency actions may be taken, if necessary.

(3) A platform well shall be monitored, but a person need not remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mud line and the master valve closed, unless otherwise approved by the District Supervisor.

(4) The well shall not be allowed to flow while the subsurface safety device is removed, except when flowing the well is necessary for that particular operation. The provisions of this paragraph are not applicable to the testing and inspection procedures in § 250.124 of this part.

(i) *Additional safety equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface safety device is installed after the effective date of this subpart shall be equipped with a landing nipple with flow couplings or other protective equipment above and below to provide for the setting of the SSSV. The control system for all surface-controlled SSSV's shall be an integral part of the platform Emergency Shutdown System (ESD). In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled SSSV's shall close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

(j) *Emergency action.* In the event of an emergency, such as an impending storm, any well not equipped with a subsurface safety device and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993]

§ 250.122 Design, installation, and operation of surface production-safety systems.

(a) *General.* All production facilities, including separators, treaters, compressors, headers, and flowlines shall be designed, installed, and maintained in a manner which provides for efficiency, safety of operation, and protection of the environment.

(b) *Platforms.* All platform production facilities shall be protected with a

basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms. If processing components are to be utilized, other than those for which Safety Analysis Checklists are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system. Safety device requirements for pipelines are contained in § 250.154 of this part.

(c) *Specification for surface safety valves (SSV) and underwater safety valves (USV).* All wellhead SSV's, USV's, and their actuators which are installed in the OCS shall conform to the requirements in § 250.126 of this part.

(d) *Use of SSV's and USV's.* All SSV's and USV's shall be inspected, installed, maintained, and tested in accordance with API RP 14H, Recommended Practice for Use of Surface Safety Valves and Underwater Safety Valves Offshore. If any SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(e) *Approval of safety-systems design and installation features.* Prior to installation, the lessee shall submit, in duplicate for approval to the District Supervisor a production safety system application containing information relative to design and installation features. Information concerning approved design and installation features shall be maintained by the lessee at the lessee's offshore field office nearest the OCS facility or other location conveniently available to the District Supervisor. All approvals are subject to field verifications. The application shall include the following:

(1) A schematic flow diagram showing tubing pressure, size, capacity, design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, pipeline pumps, metering devices, and other hydrocarbon-handling vessels.

(2) A schematic flow diagram (API RP 14C, Figure E1) and the related Safety Analysis Function Evaluation chart (API RP 14C, subsection 4.3c).

(3) A schematic piping diagram showing the size and maximum allowable working pressures as determined in accordance with API RP 14E, Design and Installation of Offshore Production Platform Piping Systems.

(4) Electrical system information including the following:

(i) A plan for each platform deck outlining all hazardous areas classified in accordance with API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outlined shall include the following information:

(A) All major production equipment, wells, and other significant hydrocarbon sources and a description of the type of decking, ceiling, walls (e.g., grating or solid) and firewalls; and

(B) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (e.g., type cable, conduit, or wire).

(ii) Elementary electrical schematic of any platform safety shut-down system with a functional legend.

(5) Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that new installations conform to the approved designs of this subpart.

(6) The design and schematics of the installation and maintenance of all fire- and gas-detection systems shall include the following:

(i) Type, location, and number of detection sensors;

(ii) Type and kind of alarms, including emergency equipment to be activated;

(iii) Method used for detection;

(iv) Method and frequency of calibration; and

(v) A functional block diagram of the detection system, including the electric power supply.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60024, Nov. 26, 1996]

§ 250.123 Additional production system requirements.

(a) *General.* Lessees shall comply with the following production safety system requirements (some of which are in addition to those contained in API RP 14C), incorporated by reference in § 250.122(b) of this part.

(b) *Design, installation, and operation of additional production systems.* (1) *Pressure and fired vessels.* Pressure and fired vessels shall be designed, fabricated, code stamped, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. All existing uncoded vessels in use must be justified and approval for continued use obtained from the District Supervisor no later than August 29, 1988.

(i) Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves, except completely redundant relief valves, shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

(ii) Steam generators operating at less than 15 pounds per square inch gauge (psig) shall be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level. Steam generators operating at greater than 15 psig require, in addition to an LSL, a water-feeding device which will automatically control the water level.

(iii) The lessee shall use pressure recorders to establish the new operating pressure ranges of pressure vessels at any time when there is a change in operating pressures that requires new settings for the high–pressure shut–in sensor and/or the low–pressure shut–in sensor as provided herein. The pressure-recorder charts used to determine current operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Supervisor. The high-pressure shut-in sensor shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the vessel. This setting shall also be set sufficiently below (5 percent or 5 psi, whichever is greater) the relief valve's set pressure to assure that the pressure source is shut in before the relief valve activates. The low-pressure shut-in sensor shall activate no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range. The activation of low-pressure sensors on pressure vessels which operate at less than 5 psi shall be approved by the District Supervisor on a case-by-case basis.

(2) *Flowlines.* (i) Flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located in accordance with section A.1 and Figure A1 of API RP 14C. The lessee shall use pressure recorders to establish the new operating pressure ranges of flowlines at any time when there is a significant change in operating pressures. The most recent pressure-recorder charts used to determine operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Supervisor. The high-pressure shut-in sensor(s) shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the line. But in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the SSV. The low-pressure shut-in sensor(s) shall be set no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the line in which it is installed.

(ii) If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) shall have a working

pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(A) A relief valve which vents into the platform flare scrubber or some other location approved by the District Supervisor. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid hydrocarbons which may be relieved to the vessel.

(B) Two SSV's with independent high-pressure sensors installed with adequate volume upstream of any block valve to allow sufficient time for the valve(s) to close before exceeding the maximum allowable working pressure.

(3) *Safety sensors.* All shutdown devices, valves, and pressure sensors shall function in a manual reset mode. Sensors with integral automatic reset shall be equipped with an appropriate device to override the automatic reset mode. All pressure sensors shall be equipped to permit testing with an external pressure source.

(4) *ESD.* The ESD shall conform to the requirements of Appendix C, section C1, of API RP 14C, and the following:

(i) The manually operated ESD valve(s) shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve.

(ii) Closure of the SSV shall not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV shall close in not more than 2 minutes after the shut-in signal has closed the SSV. Design-delayed closure time greater than 2 minutes shall be justified by the lessee based on the individual well's mechanical/production characteristics and be approved by the District Supervisor.

(iii) A schematic of the ESD which indicates the control functions of all safety devices for the platforms shall be maintained by the lessee on the platform or at the lessee's field office nearest the OCS facility or other location conveniently available to the District Supervisor.

(5) *Engines.* (i) *Engine exhaust.* Engine exhausts shall be equipped to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4). Exhaust piping from diesel engines shall be equipped with spark arresters.

(ii) *Diesel engine air intake.* No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shutdown the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

(6) *Glycol dehydration units.* A pressure relief system or an adequate vent shall be installed on the glycol regenerator (reboiler) which will prevent overpressurization. The discharge of the relief valve shall be vented in a nonhazardous manner.

(7) *Gas compressors.* Compressor installations shall be equipped with the following protective equipment as required in API RP 14C, sections A4 and A8.

(i) A Pressure Safety High (PSH), a Pressure Safety Low (PSL), a Pressure Safety Valve (PSV), and a Level Safety High (LSH), and an LSL to protect each interstage and suction scrubber.

(ii) A Temperature Safety High (TSH) on each compressor discharge cylinder.

(iii) The PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designed to actuate automatic shutdown valves (SDV) located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources. All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Supervisor, gas-well gas affected by the closure of the automatic SDV on a compressor suction shall be diverted to the pipeline or shut in at the wellhead.

(iv) A blowdown valve is required on the discharge line of all compressor installations of 1,000 horsepower (746 kilowatts) or greater.

(8) *Firefighting systems.* Firefighting systems for both open and totally enclosed platforms installed for extreme weather conditions or other reasons shall conform to subsection 5.2, Firewater systems, of API RP 14G, Fire Prevention and Control Open Type Offshore Production Platforms, and shall require approval of the District Supervisor. The following additional requirements shall apply for both open- and closed-production platforms:

(i) A firewater system consisting of rigid pipe with firehose stations or fixed firewater monitors shall be installed. The firewater system shall be installed to provide needed protection in all areas where production-handling equipment is located. A fixed waterspray system shall be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(ii) Fuel or power for firewater pump drivers shall be available for at least 30 minutes of run time during a platform shut-in. If necessary, an alternate fuel or power supply shall be installed to provide for this pump-operating time unless an alternate firefighting system has been approved by the District Supervisor.

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Supervisor determines that the use of a chemical system provides equivalent fire-protection control.

(iv) A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the facility or structure.

(v) For operations in subfreezing climates, the lessee shall furnish evidence to the District Supervisor that the firefighting system is suitable for the conditions.

(9) *Fire- and gas-detection system.* (i) Fire (flame, heat, or smoke) sensors shall be installed in all enclosed classified areas. Gas sensors shall be installed in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation which is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit (LEL). One approved method of providing adequate ventilation is a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater. Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more than four of their six possible sides by walls, floors, or ceilings more restrictive to air flow than grating or fixed open louvers and of sufficient size to all entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500.

(ii) All detection systems shall be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas concentration levels shall be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(iii) A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility which are provided with fuel gas. Living quarters and doghouses not containing a gas source and not located in a classified area do not require a gas detection system.

(iv) The District Supervisor may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems shall be an approved type, designed and installed in accordance with API RP 14C, API RP 14G, and API RP 14F, Design and Installation of Electrical Systems for Offshore Production Platforms.

(10) *Electrical equipment.* Electrical equipment and systems shall be designed, installed, and maintained in accordance with the requirements in § 250.53 of this part.

(11) *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic,

or other satisfactory monitoring methods. Records by lease, indicating the wells which have erosion-control programs in effect and the results of the programs, shall be maintained by the lessee for a period of 2 years and shall be made available to MMS upon request.

(c) *General platform operations.* (1) Surface or subsurface safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices shall be taken out of service. Personnel shall monitor the bypassed or blocked-out functions until the safety devices are placed back in service. Any surface or subsurface safety device which is temporarily out of service shall be flagged.

(2) When wells are disconnected from producing facilities and blind flanged, equipped with a tubing plug, or the master valves have been locked closed, compliance is not required with the provisions of API RP 14C or this regulation concerning the following:

(i) Automatic fail-close SSV's on wellhead assemblies, and

(ii) The PSH and PSL shut-in sensors in flowlines from wells.

(3) When pressure or atmospheric vessels are isolated from production facilities (e.g., inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device compliance with API RP 14C or this subpart is not required.

(4) All open-ended lines connected to producing facilities and wells shall be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(d) *Welding and burning practices and procedures.* All welding, burning, and hot-tapping activities shall be conducted according to the specific requirements in § 250.52 of this part.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988, as amended at 55 FR 47753, Nov. 15, 1990; 61 FR 60025, Nov. 26, 1996]

§ 250.124 Production safety-system testing and records.

(a) *Inspection and testing.* The safety-system devices shall be successfully inspected and tested by the lessee at the interval specified below or more frequently if operating conditions warrant. Testing shall be in accordance with API RP 14C, Appendix D, and the following:

(1) Testing requirements for subsurface safety devices are as follows:

(i) Each surface-controlled subsurface safety device installed in a well, including such devices in shut-in and injection wells, shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, or if a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. Testing shall be in accordance with API RP 14B to ensure proper operation.

(ii) Each subsurface-controlled SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple.

(iii) Each tubing plug installed in a well shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. An additional tubing plug may be installed in lieu of removal.

(iv) Injection valves shall be tested in the manner as outlined for testing tubing plugs in paragraph (a)(1)(iii) of this section. Leakage rates outlined in paragraph (a)(1)(iii) of this section shall apply.

(2) All PSV's shall be tested for operation at least once every 12 months. These valves shall be either bench-tested or equipped to permit testing with an external pressure source. Weighted disk vent valves used as PSV's on atmospheric tanks may be disassembled and inspected in lieu of function testing.

(3) The following safety devices shall be tested at least once each calendar

month, but at no time shall more than 6 weeks elapse between tests:

(i) All PSH and PSL,

(ii) All LSH and LSL controls,

(iii) All automatic inlet SDV's which are actuated by a sensor on a vessel or compressor, and

(iv) All SDV's in liquid discharge lines and actuated by vessel low-level sensors.

(4) All SSV's and USV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The testing shall be in accordance with the test procedures specified in API RP 14H, Section 4, Table 2. If the SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(5) All flowline Flow Safety Valves (FSV) shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's shall be tested for leakage in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection D. If the leakage measured exceeds a liquid flow of 200 cubic centimeters per minute or a gas flow of 5 cubic feet per minute, the FSV's shall be repaired or replaced.

(6) The TSH shutdown controls installed on compressor installations which can be nondestructively tested shall be tested every 6 months and repaired or replaced as necessary.

(7) All pumps for firewater systems shall be inspected and operated weekly.

(8) All fire- (flame, heat, or smoke) detection systems shall be tested for operation and recalibrated every 3 months provided that testing can be performed in a nondestructive manner. Open flame or devices operating at temperatures which could ignite a methane-air mixture shall not be used. All combustible gas-detection systems shall be calibrated every 3 months.

(9) All TSH devices shall be tested at least once every 12 months, excluding those addressed in paragraph (a)(6) of this section and those which would be destroyed by testing. Burner safety low and flow safety low devices shall also be tested at least once every 12 months.

(10) The ESD shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The test shall be conducted by alternating ESD stations monthly to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation.

(11) Prior to the commencement of production, the lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a complete inspection may be conducted.

(b) *Records.* The lessee shall maintain records for a period of 2 years for each subsurface and surface safety device installed. These records shall be maintained by the lessee at the lessee's field office nearest the OCS facility or other locations conveniently available to the District Supervisor. These records shall be available for review by a representative of MMS. The records shall show the present status and history of each device, including dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47753, Nov. 15, 1990; 62 FR 5331, Feb. 5, 1997]

§ 250.125 Safety device training.

Personnel installing, inspecting, testing, and maintaining these safety devices and personnel operating the production platforms shall be qualified in accordance with subpart O.

§ 250.126 Quality assurance and performance of safety and pollution prevention equipment.

(a) Safety and pollution prevention equipment installed on the OCS shall meet the quality assurance requirements identified in paragraph (c) of this section. The MMS will consider approval of other quality assurance programs for the manufacture of safety and pollution prevention equipment. Quality assurance programs proposed

for consideration by MMS shall be submitted to the Deputy Associate Director for Offshore Operations; Minerals Management Service; Mail Stop 647; 381 Elden Street; Herndon, Virginia 22070—4817.

(b)(1) By August 29, 1988, each lessee shall submit to the Deputy Associate Director for Offshore Operations a list of all certified and noncertified SSV's (both actuator and valve), USV's (both actuator and valve), and SSSV's (including safety valve locks and landing nipples) in the lessee's inventory as of April 1, 1988. The list shall indicate which items of the safety and pollution-prevention equipment were manufactured under American National Standards Institute/American Society of Mechanical Engineers Standard ANSI/ASME SPPE–1, Quality Assurance and Certification of Safety and Pollution-Prevention Equipment Used in Offshore Oil and Gas Operations and shall identify each listed item by manufacturer, serial number, model, the date the item entered inventory, and whether the item is in service on the OCS or in stock for installation on the OCS.

(2) Lists received from lessees under paragraph (b)(1) of this section shall be maintained by MMS. An SSSV shall be removed from the list when it is removed from service for a failure or malfunction. A USV or an SSV shall be removed from the list when it is removed from service for remanufacture (repairs employing machining, welding, heat treating, or other manufacturing operations). Lessees shall notify the Deputy Associate Director for Offshore Operations when an SSSV is removed from service for a failure or malfunction or a USV or SSV is removed from service for remanufacture (repairs employing machining, welding, heat treating, or other manufacturing operations).

(c) Safety and pollution-prevention equipment used in the OCS shall meet one of the following:

(1) Be identified on the list submitted under paragraph (b) of this section by a lessee of the lease on which the item is to be installed,

(2) Be certified by the manufacturer as having been produced under a quality assurance program that meets the requirements of ASME/ANSI SPPE–1–1988 and addenda a, b, c, and d, or

(3) Be certified by the manufacturer as having been produced under a quality assurance program that meets the requirements of API Spec Q1 and the technical specification API Spec 14A for SSSV's. For SSV's and USV's the manufacturer must meet API Spec 6A and API Spec 6AVI, or API Spec 14D.

(d) The installation, inspection, maintenance, testing, removal, redress, field repair, and documentation of safety and pollution-prevention equipment used in the OCS shall be in accordance with API RP 14B for an SSSV and API RP 14H for an SSV or USV. A remanufactured SSV or USV shall meet the requirements of paragraph (c) of this section.

(e) Each lessee shall report the failure of safety and pollution-prevention equipment certified in accordance with paragraph (c)(2) or (3) of this section.

(1) Equipment certified under paragraph (c)(2) shall be reported in accordance with section OE–2670 of ASME/ANSI SPPE–1–1988 and addenda a, b, c, and d.

(2) Equipment certified under paragraph (c)(3) of this section, must be reported in accordance with Appendix C of API Spec 14A or Appendix L of API Spec 6A or Appendix C of API Spec 14D, as appropriate.

(3) Equipment certified under both paragraphs (c)(2) and (c)(3) of this section must be reported in accordance with both section OE–2670 of ASME/ANSI SPPE–1–1988 and Appendix C of API Spec 14A or Appendix L of API Spec 6A or Appendix C of API Spec 14D, as appropriate.

(f) Each lessee shall report the installation of equipment certified in accordance with either paragraph (c)(2) or (c)(3) of this section, to the manufacturer of the equipment on the shipping and receiving report that comes with the equipment.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988, as amended at 54 FR 50617, Dec. 8. 1989; 55 FR 10617, Mar. 22, 1990; 55 FR 37710, Sept. 13, 1990; 55 FR 47753, Nov. 15, 1990; 61 FR 60025, Nov. 26, 1996]

§ 250.127 Hydrogen sulfide.

Production operations in zones known to contain hydrogen sulfide

(H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.67 of this part, shall be conducted in accordance with that section and other relevant requirements of subpart H, Production Safety Systems.

Subpart I—Platforms and Structures

§ 250.130 General requirements.

(a) The lessee shall design, fabricate, install, use, inspect, and maintain all platforms and structures (platforms) on the Outer Continental Shelf (OCS) to assure their structural integrity for the safe conduct of drilling, workover, and production operations, considering the specific environmental conditions at the platform location.

(b) All new fixed or bottom-founded platforms (i.e., platforms or other structures, e.g., single-well caissons, artificial islands), shall be designed, fabricated, installed, inspected, and maintained in accordance with all the requirements of this section and §§ 250.131 and 250.134 through 250.144 of this subpart. Applications submitted pursuant to § 250.131 shall require the approval by the Regional Supervisor prior to platform installation.

(c) All new platforms which meet any of the conditions listed below shall be subject to the Platform Verification Program and shall be designed, fabricated, and installed in accordance with the requirements of §§ 250.131 through 250.144 of this part.

(1) Platforms installed in water depths exceeding 400 feet,

(2) Platforms having natural periods in excess of 3 seconds,

(3) Platforms installed in areas of unstable bottom conditions,

(4) Platforms having configurations and designs which have not previously been used or proven for use in the area, or

(5) Platforms installed in seismically active areas.

(d) Major modification to any platform shall be subject to the requirements of this subpart and shall require the approval of the Regional Supervisor. Major modification means any structural changes which materially alter the approved plan or causes a major deviation from approved operations.

(e)(1) Major repairs of damage to any platform shall require the prior approval of the Regional Supervisor. Major repairs of damage means corrective operations involving structural members affecting the structural integrity of a portion or all of the platform.

(2) Under emergency conditions, repairs to primary structural elements may be made to restore an existing permitted condition without prior approval. The Regional Supervisor shall be notified within 24 hours of the damage that occurred and repairs that were made. The Regional Supervisor's approval for repairs shall be obtained.

(f) The requirements for an application for approval for the reuse or conversion of the use of an existing fixed or mobile platforms shall be determined on a case-by-case basis. An application shall be submitted to the Regional Supervisor for approval and shall include location, intended use, and demonstrate the adequacy of the design and structural condition of the platform.

(g) In addition to the requirements of this subpart, platform design, fabrication, and installation shall conform to API RP 2A, Recommended Practice For Planning, Designing, And Constructing Fixed Offshore Platforms, or American Concrete Institute (ACI) 357R, Guide for the Design and Construction of Fixed Offshore Concrete Structures, as appropriate. Alternative codes or rules may be utilized with approval of the Regional Supervisor. The requirements contained in these documents (API RP 2A and ACI 357R) are incorporated herein insofar as they do not conflict with other provisions of this subpart.

§ 250.131 Application for approval.

(a) All applications under the provisions of this subpart shall be submitted to the Regional Supervisor for approval. All significant changes or modifications to approved applications shall be submitted to the Regional Supervisor for approval.

(b) Applications for all new platforms or major modifications shall be submitted in triplicate and shall contain the following information:

(1) General platform information including the following:

(i) The platform designation, lease number, area name, and block number;

(ii) Longitude and latitude coordinates, Universal Transverse Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection system, and a plat drawn to a scale of 1 inch = 2,000 feet showing surface location of the platform and distance from the nearest block lines;

(iii) Drawings, plats, front and side elevations of the entire platform, and plan views that clearly illustrate essential parts, i.e., number and location of well slots, design loadings of each deck, water depth, nominal size and thickness of all primary load-bearing jacket and deck structural members, and nominal size, makeup, thickness, and design penetration of piling;

(iv) Corrosion protection or durability details which consist of the corrosion-protection method; expected life; and durability criteria for the submerged, splash, and atmospheric zones; and

(v) In the Alaska OCS Region, the following additional information shall be submitted:

(A) Slope protection and berm elevation for manmade islands,

(B) Wall thickness with size and placement of major steel reinforcement for concrete-gravity structures,

(C) Shell thickness with size and location of major reinforcement members for steel-gravity structures, and

(D) A plan for periodic inspections of the installed platforms in accordance with § 250.142 of this part.

(2) A summary of environmental data, as addressed in § 250.134 of this part, which has a bearing on the platform's design, installation, and operation, e.g., wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperatures;

(3) Foundation information including the following:

(i) A geotechnical investigation report containing a brief summary of the major strata encountered at the location by bore holes presented in tabular form, a detailed subsurface profile illustrating results of field and laboratory testing, a listing of field and laboratory investigations and tests with a basic summary of resultant determinations, the identification of properties and conditions of the seabed and the subsoil, and the identification of any manmade hazards or obstructions;

(ii) A description of the effect of the environmental and functional loads on the foundation;

(iii) A determination, with supporting information, of the susceptibility of the area to soil movement and, if susceptible, an analysis of slope and soil stability;

(iv) A summary of the foundation design criteria as specified in § 250.139 of this part; and

(v) A summary of the seafloor survey results specified in § 250.139(b)(2) of this part.

(4) Structural information including the following:

(i) The design life of the platform and the basis for such determination.

(ii) A summary description of the design load conditions and design load combinations, taking into consideration the worst environmental and operational conditions anticipated over the service life of the platform.

(iii) A listing and description of the appropriate material specifications.

(iv) A description of the design methodologies, e.g., elastic, inelastic, and ultimate strength, used in design of the platform.

(v) A summary of pertinent derived factors of safety against failure for major structural members, e.g., unity check ratios exceeding 0.85 for steel-jacket platform members, indicated on ''line'' sketches of jacket sections.

(vi)(A) In the Alaska, Atlantic, and Pacific OCS Regions, a summary of the fatigue analysis as specified in §§ 250.135 through 250.139 of this part. The specific requirements for a fatigue analysis shall be determined by the Regional Supervisor on a case-by-case basis to determine the adequacy of the design and to assure the structural integrity of the platform.

(B) In the Gulf of Mexico OCS Region, a summary of the fatigue analysis as specified in §§ 250.135 through 250.139 of this part. A fatigue analysis

shall be performed for each steel template, pile-supported platform with natural periods greater than 3 seconds, and for each platform to be fabricated of high-strength steel (i.e., over 50 thousand pounds per square inch minimum yield) where components of high-strength steel are subjected to cyclic loading. The specific requirements for a fatigue analysis for other platforms shall be determined by the Regional Supervisor on a case-by-case basis to determine adequacy of the design and to assure the structural integrity of the platform.

(c) The information shall be submitted with or subsequent to the submittal of an Exploration Plan or Development and Production Plan. Additional detailed data and information may be required by the Regional Supervisor when needed to determine the adequacy of the design.

(d) The lessee shall have detailed structural plans as called for in paragraph (b)(1)(iii) of this section and specifications for new platforms or other structures and major modifications certified by a registered professional structural engineer or civil engineer specializing in structural design. The lessee shall also sign, date, and submit the following certification: Lessee certifies that the design of the structure/modification has been certified by a registered professional structural or a civil engineer specializing in structural design, and the structure/modification will be fabricated, installed, and maintained as described in the application and any approved modification thereto. Certified design and as built plans and specifications will be on file at———.

(e) The lessee shall notify the Regional Supervisor at least 1 week prior to transporting the platform to the installation site.

§ 250.132 Platform Verification Program requirements.

(a) *Requirements.* These requirements apply to the design, fabrication, and installation of new, fixed, bottom-founded, pile-supported, or concrete-gravity platforms. The applicability of these requirements to other types of platforms shall be determined by the MMS on a case-by-case basis. For all new platforms or major modifications which meet any of the conditions contained in § 250.130(c) of this part, the lessee shall submit the design, fabrication, and installation verification plans to the Regional Supervisor for approval in accordance with paragraph (b) of this section. The design plan shall be submitted with or subsequent to the submittal of an Exploration Plan or Development and Production Plan. The fabrication and installation plans shall be submitted and approval obtained before such operations are initiated.

(b) *Verification plan requirements.* (1) *General plan requirements.* Each verification plan shall be submitted in triplicate and include the following:

(i) A nomination of a Certified Verification Agent (CVA) who shall conduct specified reviews in accordance with § 250.133 of this part,

(ii) The CVA qualification statement consisting of the following:

(A) Previous experience in third-party verification or experience in the design, fabrication, and/or installation of offshore oil and gas platforms, man-made islands, or other marine structures;

(B) Technical capabilities of the individual or the primary staff to be associated with the CVA functions for the specific project;

(C) Size and type of organization or corporation;

(D) In-house availability of, or access to, appropriate technology, i.e., computer programs and hardware and testing materials and equipment;

(E) Ability to perform the CVA functions for the specific project considering current commitments; and

(F) Previous experience with MMS requirements and procedures.

(iii) The level of work to be performed by the CVA, and

(iv) A list of documents to be furnished to the CVA.

(2) *Design verification plan requirements.* The design plan shall also include the following:

(i) All design documentation specified in § 250.131(b) of this part, and

(ii) Abstracts of the computer programs used in the design process.

(3) *Fabrication verification plan requirements.* The fabrication plan shall also include fabrication drawings and

material specifications for artificial island structures, major members of concrete- and steel-gravity structures, all the primary load-bearing members included in the space-frame analysis for jacket structures, and a summary description of the following:

(i) Structural tolerances,

(ii) Welding procedures,

(iii) Material (concrete, gravel, or silt) placement methods,

(iv) Fabrication standards,

(v) Material quality-control procedures,

(vi) Methods and extent of nondestructive examinations (NDE) for welds and materials, and

(vii) Quality assurance procedures.

(4) *Installation verification plan requirements.* Additionally, the installation plan shall include a summary description of the planned marine operations, contingencies considered, alternate courses of action, and the inspections to be performed including a graphical identification of areas to be inspected and the acceptance/rejection criteria.

(c) *Requirements for resubmittal.* All such plans or the appropriate part affected shall be resubmitted for approval if the CVA is changed, if the CVA's or assigned personnel's qualifications change, or if the level of work to be performed changes. The summary of technical details need not be resubmitted, unless changes are made in the technical details.

(d) *Combining of plans.* For manmade islands or platforms fabricated and installed in place, the fabrication and installation verification plans shall be combined.

§ 250.133 Certified Verification Agent duties and nomination.

(a) *CVA duties.* The CVA nominated by the lessee and approved by the Regional Supervisor shall conduct the appropriate reviews in accordance with the following:

(1) *Design phase.* (i) The CVA shall conduct the design verification to ensure that the proposed platform or major modification has been designed to withstand the maximum environmental and functional load conditions anticipated during the intended service life at the proposed location.

(ii) The design verification shall be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer.

(iii) The CVA shall consider the applicable provisions of §§ 250.134 through 250.141 of this part and use good engineering practice in conducting an independent assessment of the adequacy of all proposed planning criteria, environmental data, load determinations, stress analyses, material designations, soil and foundation conditions, safety factors, and other pertinent parameters of the proposed design.

(iv) Interim reports shall be submitted by the CVA, as appropriate, to the Regional Supervisor and the lessee.

(v) Upon completion of the design verification, a final report shall be prepared which summarizes the material reviewed by the CVA and the findings and includes a recommendation that the Regional Supervisor either accept, request modification(s), or reject the proposed design. In addition, the report shall include the particulars of how, by whom, and when the independent review was conducted and any special comments considered necessary. The final report shall be submitted to the lessee and, in triplicate, to the Regional Supervisor within 6 weeks of the receipt of the design data or from the date the approval to act as a CVA was issued, whichever is later.

(2) *Fabrication verification.* The CVA shall monitor the fabrication of the platform or major modification to ensure that it has been built in accordance with the approved design plans and specifications and the fabrication plan, including the following:

(i) Periodic onsite inspections shall be made while fabrication is in progress. The following of the fabrication items, as appropriate, shall be verified:

(A) Quality control by lessee and builder,

(B) Fabrication site facilities,

(C) Material quality and identification methods,

(D) Fabrication procedures specified in the approved plan and adherence to such procedures,

(E) Welder and welding procedure qualification and identification,

(F) Structural tolerances specified and adherence to those tolerances,

(G) The NDE requirements and evaluation results of the specified examinations,

(H) Destructive testing requirements and results,

(I) Repair procedures,

(J) Installation of corrosion-protection systems and splash-zone protection,

(K) Erection procedures to ensure that overstressing of structural members does not occur,

(L) Alignment procedures,

(M) Dimensional check of the overall structure, and

(N) Status of quality-control records at various stages of fabrication.

(ii) The CVA shall consider the applicable provisions of §§250.134 through 250.141 of this part and use good engineering practice in conducting an independent assessment of the adequacy of the fabrication of the platform or major modification.

(iii) Interim reports shall be submitted by the CVA, as appropriate, to the Regional Supervisor and the lessee.

(iv) If the CVA finds that fabrication procedures are changed or design specifications are modified, the lessee shall be informed. If the lessee prefers to accept the modifications as informed by the CVA, the Regional Supervisor shall also be informed.

(v) A final report shall be prepared by the CVA covering the adequacy of the entire fabrication phase giving details of how, by whom, and when the independent monitoring activities were conducted and providing any special comments considered necessary. The final report is not required to cover aspects of the fabrication already included in interim reports. The final report shall describe the CVA's activities during the verification process, summarize the findings, contain a confirmation or denial of compliance with the design specifications and the approved fabrication plan, and a recommendation to accept or reject the fabrication. The report shall be submitted to the lessee and, in triplicate, to the Regional Supervisor immediately after completion of the fabrication of the platform.

(3) *Installation phase.* The CVA shall witness the loadout of the jacket, deck(s), and piles from the fabrication site(s); review the towing records; conduct an onsite survey after transportation to the approved location; witness the actual installation of the platform or major modification; determine that the platform has been installed at the approved location in accordance with the approved design and the installation plan; and shall comply with the following:

(i) The CVA shall consider the applicable provisions of §§250.134 through 250.141 of this part and use good engineering practice in conducting an independent assessment of the adequacy of the installation activities. The following parts of the overall installation process, as appropriate, shall be verified:

(A) Loadout and initial flotation operations, if any;

(B) Towing operations to the specified location;

(C) Launching and uprighting operations;

(D) Submergence operations;

(E) Pile installation; and

(F) Final deck and/or component installation.

(ii) The CVA shall observe the installation activities, spot-check equipment, procedures, and recordkeeping, as necessary, to determine compliance with §§250.134 through 250.141 of this part and the approved plans, and immediately report to the Regional Supervisor and the lessee any discrepancies or damage to structural members. Approval for modified installation procedures or for major deviation from approved installation procedures shall be obtained from the Regional Supervisor.

(iii) Interim reports shall be submitted by the CVA, as appropriate, to the Regional Supervisor and the lessee.

(iv) A final report shall be prepared by the CVA covering the adequacy of the entire installation phase giving details of how, by whom, and when the independent monitoring activities were conducted and providing any special comments considered necessary. The final report shall describe the CVA's activities during the verification process, summarize the findings, contain a confirmation or denial of compliance

with the approved installation plan, and a recommendation to accept or reject the installation. The report shall be submitted to the lessee and, in triplicate, to the Regional Supervisor within 2 weeks of completion of the installation of the platform.

(4) All data provided to the CVA shall be handled in the strictest confidence and not be released by the CVA without the consent of the lessee.

(5) Individuals or organizations acting as CVA's for a particular platform shall not function in any capacity other than that of a CVA for that specific project, whenever the additional activities would create a conflict, or appearance of a conflict of interest.

(b) *CVA nomination.* (1) *Nomination.* Individuals or organizations shall be nominated by the lessee planning to use their services. The lessee shall specify whether the nomination is for the design, fabrication, or installation phase of verification; for two phases; or for all three phases.

(2) *Qualifications.* Qualification submissions shall contain sufficient information to determine compliance with § 250.132(b)(1)(ii) of this part.

§ 250.134 Environmental conditions.

(a) *General.* The performance standards of this section pertain to all platforms covered by these requirements regardless of the fabrication material.

(1) *Environmental considerations.* All environmental phenomena appropriate to the areas of fabrication, transportation, and installation of an offshore platform shall be considered and their influence on the platform accounted for. Such phenomena shall include wind, waves, current, temperature, tide, marine growth, chemical components of air and water, snow and ice, earthquakes, tsunami, seiche, and other appropriate phenomena.

(2) *Environmental data.* Statistical data and defensible statistical and mathematical models shall be employed to describe the range of pertinent expected variations of environmental phenomena. Defensible data supplied by meteorologists, oceanographers, or other appropriate specialists are acceptable as the basis for design. Where possible, environmental phenomena shall be described by the characteristic parameters most relevant in the evaluation of effects on the platform.

(b) *Statistical methods.* (1) When statistical methods are employed in the determination of parameters characterizing environmental phenomena, the statistical methods and distributions employed shall be appropriate to their application as evidenced by relevant statistical tests, confidence limits, and other measures of statistical significance.

(2) Short-term and long-term variations of environmental phenomena such as wind, waves, and current shall be described by statistical distributions relevant to the parameter considered. Defensible statistical modeling techniques shall be used in the prediction of extreme values.

(3) When hindcasting techniques are employed to approximate environmental parameters, the validity of the model used shall be defensible.

(c) *Design considerations.* (1) *General.* A thorough assessment of the environment in the vicinity of the installation site shall be made to determine the conditions expected to occur at the site over the life of the platform.

(2) *Design environmental condition.* (i) ''Design environmental condition'' means the environmental factors producing the most unfavorable effects on the platform. Parameters describing the design environmental condition are given in paragraphs (c)(2)(ii) (A), (B), and (C) of this section.

(ii) The design environmental condition shall reflect the various environmental events that individually or collectively represent the most severe conditions the platform is anticipated to experience. Such conditions shall be formulated with a set of parameters that describe the relevant environmental events, including the following:

(A) The maximum wave corresponding to a selected recurrence period together with the associated wind, current, and appropriate ice and snow effects;

(B) The minimum air and sea temperatures appropriate to the event being treated; and

(C) The maximum water level due to tide and storm surge.

(iii) Consideration shall be given to other combinations of the parameters specified in paragraph (c)(2)(ii)(A) of this section involving either maximum wind, maximum current, or maximum ice load which may cause a greater response of the platform.

(iv) In general, the recurrence period chosen for the events specified in paragraphs (c)(2)(ii) (A) and (C) of this section shall primarily be based on the design service life of the platform. For platforms designed for a service life of 20 years, the recurrence period chosen for the determination of these events shall not be less than 100 years. For other service lives, the design event recurrence interval shall generally be adjusted to provide for a risk of occurrence which does not exceed the risk of occurrence for the 20-year/100-year combination.

(v) For installation sites located in seismically active areas, see paragraph (d)(8) of this section.

(3) *Operating environmental conditions.* Operating environmental conditions means the set of characteristic parameters of environmental conditions associated with a normal function or operation to be conducted on the platform. For each such intended normal function or operation, the lessee shall determine a set of characteristic parameters of environmental conditions.

(d) *Specific environmental conditions.* (1) Waves information including the following:

(i) Wave conditions considered for design shall be described by defensible statistical and/or deterministic methods.

(ii) Parameters characterizing design environmental waves shall be based on wave statistics or the results of defensible analytic prediction methods such as hindcasting techniques.

(iii) When using probabilistic analyses, the probability of occurrence of various wave-height groups classified by directionality and for a wide range of possible periods (i.e., tables of exceedance) shall be determined. Where required by the method selected to predict extreme values, the average duration of various wave-height groups (i.e., persistence data) shall be determined. All extrapolations and long-term wave data analyses shall use defensible techniques, and available data on extreme values measured in the vicinity of the site shall be included in the long-term prediction.

(iv) When using deterministic methods, waves shall be described by the parameters, height, period, and other relevant shape characteristics. The design-wave formulation used shall be valid for the problem considered.

(v) Breaking-wave criteria appropriate to the installation site shall be determined using defensible formulations.

(vi) If spectral wave data are established for the dynamic analysis of structural response to waves, such data shall be derived in accordance with defensible methods. If spectral data are not available in adequate quantities for the intended application, defensible mathematical formulations that best fit the available data shall be used.

(2) Wind information including the following:

(i) Wind velocities shall be classified on the basis of their duration. Wind velocities having a duration of less than 1 minute are referred to as gust winds. Wind velocities having a duration equal to or greater than 1 minute are referred to as sustained winds. The reference elevation is 33 feet above still-water level.

(ii) Wind conditions considered for design shall be described by defensible statistical or deterministic methods.

(iii) Wind profiles shall be determined on the basis of defensible statistical or mathematical models. Corrections of wind velocity data to averaging periods other than those employed in the collections of data shall be based on defensible methods.

(iv) Distribution of the direction and speed of wind approach to the platform shall be determined, or alternatively, winds shall be considered to approach from any direction.

(3) Current information including the following:

(i) Current velocities to be used in design shall be determined on the basis of the best statistics available. Tidal current, wind-generated current, density current, circulation current, and river-outflow current shall be combined on

the basis of their probability of simultaneous occurrence in arriving at current velocities to be used in design.

(ii) Current velocity profiles shall be determined on the basis of site-specific studies or defensible empirical relationships. Unusual profiles due to bottom currents and stratified effects in regions near the mouth of large rivers shall be accounted for.

(iii) Directional data on currents which exist in the absence of waves shall be described for each month or by season. Unless a detailed study of current directions is made, currents shall be assumed to run in any direction.

(4) Tide information including the following:

(i) The design storm-tide elevation shall be identified for the installation site. For design purposes, the design environmental wave height shall be superimposed on the storm-tide elevation.

(ii) Variations in the elevation of the daily lunar tide shall be used in determining the elevations of boat landings, barge fenders, and the corrosion-prevention treatment of platforms in the splash zone (see § 250.136(c)(5) of this part).

(iii) The assumed maximum or storm tide shall include astronomical tide, wind tide, and pressure-induced storm surge. Minimum-tide estimates shall be based on either the astronomical or lunar tide only. The water depth shall be referenced to a datum (e.g., mean low/water or mean low low/water) consistent with all other references to elevations and depths.

(iv) If data directly applicable to the installation site are not available, the best estimate based on data for nearby locations shall be used.

(5) Temperature information including the following:

(i) Extreme values of low temperatures shall be expressed in terms of the most probable, lowest values with their corresponding recurrence periods;

(ii) Air, sea surface, and seabed temperatures shall be accounted for in describing the environment and in justifying the temperatures used in design.

(6) Snow and ice information including the following:

(i) If the platform is to be located in an area where sea ice may develop or drift, ice conditions shall be accounted for. Data shall be derived from actual field investigations, laboratory analyses, or other appropriate analogous sources;

(ii)(A) Relevant statistical and physical data on the sea-ice and snow conditions shall be described with particular attention to the following:

(*1*) Concentration and distribution of ice and snow,

(*2*) Morphology of sea ice (e.g., ice floes, ice ridges, or rafted ice),

(*3*) Mechanical properties of ice (mode of failure),

(*4*) Drift speed and direction,

(*5*) Thickness of ice and keel depth of pressure ridges, and

(*6*) Probability of encountering icebergs, ice floes, ice-floe fragments, and hummocks.

(B) The weight of the maximum snow and ice anticipated to accumulate on the platform shall be determined.

(7) Marine growth information including the following:

(i) When assessing the potential for marine growth, account shall be taken of relevant observations and experience in the area. In the absence of such information, defensible analytical techniques shall be employed to assess the potential for marine growth. These techniques shall take into account salinity, oxygen content, hydrogen-ion concentration value, current, temperature, water turbidity, and other appropriate factors.

(ii) Consideration shall be given to the selection of surface coatings which resist breakdown by micro-organisms which reduce the onset of corrosion.

(iii) Particular attention shall be paid to the effects that marine growth has on surface roughness characteristics of submerged structural members.

(8) Earthquake information including the following:

(i) The effects of earthquakes on platforms located in areas known to be seismically active shall be addressed.

(ii) Except for the provision of § 250.135(d)(5)(ii) of this part, the seismicity of the site shall be determined. Preferably, this shall be based on site-specific data. However, regional data shall be deemed acceptable for use

when site-specific data are not available and the regional data are interpreted in a manner to produce the most adverse effect on a platform at the specific site. The following data shall be obtained:

(A) Recurrence interval of seismic events appropriate to the design life of the structure,

(B) Proximity to active faults,

(C) Type of faulting,

(D) Attenuation of ground motion between the faults and the site,

(E) Subsurface soil conditions, and

(F) Records from past seismic events at the site or from analogous sites.

(iii) The use of available data to describe the seismic characteristics of the site is permitted where it can be shown that such data are consistent with the requirements of paragraph (d)(8)(ii) of this section.

(iv) The seismic data shall be used to establish a quantitative design earthquake criterion describing the design earthquake-induced ground motion. In addition to ground motion and as applicable to the installation site, the following earthquake-related phenomena shall be taken into account:

(A) Liquefaction of subsurface soils,

(B) Submarine slides,

(C) Tsunamis, and

(D) Fluid motions in tanks.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988]

§ 250.135 Loads.

(a) *Introduction*. This section covers the identification, definition, and determination of the loads to which a fixed offshore platform may be exposed during and after its transportation and installation. The requirements contained in paragraphs (b) through (d) of this section apply to both steel-piled platforms and concrete-gravity platforms. Additional requirements covering steel-piled platforms are contained in paragraph (e) of this section. Additional requirements covering concrete-gravity platforms are contained in paragraph (f) of this section.

(b) *General*. (1) All types of loads specified in paragraphs (c)(1) through (c)(5) of this section shall be accounted for in the design and operation of the platform.

(2) Where applicable, the effects of increased dimensions and weight due to marine growth and snow and ice accumulation shall be addressed in the design.

(c) *Load definition*. (1) *Dead loads*. Dead loads associated with the platform are loads that do not change during the mode of operation under consideration. Dead loads include the following:

(i) Weight in the air of the platform (refer to paragraphs (e)(1) and (f)(1) of this section for itemizations of weight for pilefounded platforms and gravity platforms, respectively).

(ii) Weight of permanent ballast and the weight of permanent machinery including liquids at operating levels.

(iii) External hydrostatic pressure and buoyancy in calm sea conditions calculated on the basis of the design waterline.

(iv) Static earth pressure.

(2) *Live loads*. Live loads associated with the normal operation and use of the platform are loads that could change during the mode of operation considered. Live loads acting after fabrication or installation include the following:

(i) Weight of drilling and production equipment that can be removed such as derrick, draw works, mud pumps, mud tanks, separators, and tanks.

(ii) Weight of crew and consumable supplies such as mud, chemicals, water, fuel, pipe, cable, stores, drill stem, and casing.

(iii) Weight of liquids in storage tanks.

(iv) Forces exerted on the platform due to drilling, e.g., the maximum derrick reaction when placing or pulling casing.

(v) The forces exerted on the platform during the operation of cranes and vehicles.

(vi) The forces exerted on the platform by vessels moored to the platform.

(vii) The forces exerted on the platform by helicopters during takeoff and landing or while parked on the platform. When applicable, the dynamic effects on the platform of the forces specified in paragraphs (c)(2) (iv) through (vii) of this section shall be taken into account. Live loads occurring during

transportation and installation shall be determined for each specific operation involved, and the dynamic effects of such loads shall be addressed (see § 250.140 of this part).

(3) *Deformation loads.* Deformation loads are loads due to deformations imposed on the platform. For an itemization of deformation loads applicable to steel-piled platforms and concretegravity platforms, see paragraphs (e)(2) and (f)(2) of this section, respectively.

(4) *Accidental loads.* Consideration shall be given to accidental loadings; and where such loadings are determined to be a factor, they shall be quantified and incorporated into the design. Accidental loads are loads that could occur as the result of an accident or exceptional conditions, such as the following:

(i) Extreme impact loads caused by supply boats, barges, and other craft anticipated to work in the vicinity of the platform;

(ii) Impact loads caused by dropped objects, such as drill collars, casing, blowout-preventer stacks;

(iii) Loss of internal pressure required to resist hydrostatic loading and to maintain buoyancy during the installation of the platform;

(iv) Explosion;

(v) Effects of fire; and

(vi) Iceberg collision.

(5) Environmental load information including the following:

(i) Environmental loads are loads due to wind, waves, current, ice, snow, earthquake, and other environmental phenomena.

(ii) The characteristic parameters defining an environmental load shall be appropriate to the installation site as determined by the studies required by § 250.134 of this part. Operating environmental loads are loads derived from the parameters characterizing operating environmental conditions (see § 250.134(c)(3) of this part). Design environmental loads are loads derived from the parameters characterizing the design environmental condition (see § 250.134(c)(2) of this part).

(iii) Environmental loads shall be applied to the platform from directions producing the most unfavorable effects on the platform unless site-specific studies allow for a less stringent requirement.

(iv) The combination and severity of design environmental loads shall be consistent with the likelihood of their simultaneous occurrence. The simultaneous occurrence of environmental loads shall be modeled by appropriate superposition methods.

(v) Earthquake loads and loads resulting from accidental or rare environmental phenomena need not be combined with other environmental loads unless site-specific conditions indicate that such combination is appropriate.

(d) *Determination of environmental loads.* (1) Wave load information including the following:

(i) Wave-induced loads shall be calculated using defensible methods or shall be obtained from adequate model or field test data;

(ii) A sufficient range of waves and wavecrest positions relative to the platform shall be investigated to ensure an accurate determination of the maximum wave load on the platform;

(iii) Wave impact loads on structural members below the design wave crest elevation shall be accounted for by defensible theoretical methods or relevant model test of full-scale data;

(iv) Where applicable, the possibility of dynamic excitation of the platform due to flow-induced cyclic loading shall be addressed;

(v) For additional requirements pertaining to steel-piled platforms and concrete gravity-platforms, see paragraphs (e)(3) and (f)(3) of this section, respectively; and

(vi) Where applicable, additional hydrostatic loading effects shall be addressed.

(2) Wind load information including the following:

(i) Wind loads, local wind pressures, and wind profiles shall be determined on the basis of defensible analytical methods or wind tunnel tests on a representative model of the platform,

(ii) In determining design environmental loads on the overall platform, wind loads calculated on the basis of the design-sustained wind velocity shall be combined with other design environmental loads,

(iii) The design gust wind load shall be used in the design of local structure unless the effects of the load combination described in paragraph (d)(2)(ii) of this section are more severe,

(iv) Where appropriate, the dynamic effects due to the cyclic nature of gust wind and cyclic loads due to vortex shedding shall be taken into account. Both the drag and lift components of loads due to vortex shedding shall be taken into account.

(v) Where appropriate, flutter and load amplification due to vortex shedding shall be addressed.

(3) Current load information including the following:

(i) Current-induced loads on immersed members of the platform shall be accounted for by defensible methods or the results of model test or site-specific data,

(ii) The lift and drag coefficients used in the determination of current loads shall be appropriate to the current velocity and structural configuration,

(iii) Current velocity profiles used in design shall be appropriate to the installation site,

(iv) For determination of loads induced by the simultaneous occurrence of wave and current fields, the total velocity field shall be computed by defensible methods before computing the total force, and

(v) Where appropriate, flutter and load amplification due to vortex shedding shall be addressed.

(4) Ice and snow load information including the following:

(i) For platforms located in areas associated with ice movement, contact loads caused by floating ice shall be determined according to defensible theoretical methods, model test data, or full-scale measurements;

(ii) In locations where platforms are subject to ice and snow accumulation, the additional weight of snow and ice on the platform shall be addressed;

(iii) The effects of ice accumulation and ice jam, including the effects of changes in configuration due to adhesion, shall be accounted for in the determination of the total environmental load; and

(iv) The incident pressure due to pack ice, pressure ridges, and where appropriate, ice island fragments impinging on the platform shall be addressed.

(5) Earthquake load information including the following:

(i) For platforms located in seismically active areas, design earthquake-induced ground motions shall be determined on the basis of seismic data applicable to the installation site. Design earthquake ground motions shall be described by either applicable ground motion records or response spectra consistent with the recurrence period appropriate to the design life of the platform.

(ii) Available and defensible standardized spectra applicable to the region of the installation site are acceptable if such spectra reflect those site-specific conditions affecting frequency content and energy distribution. These conditions include the type of active faults in the region, the proximity of the site to the potential source faults, the attenuation or amplification of ground motion between the faults and the site, and the soil conditions at the site.

(iii) Ground-motion descriptions shall consist of three components corresponding to two orthogonal horizontal directions and the vertical direction. All three components shall be applied to the platform simultaneously.

(iv)(A) When the response spectrum method is used for structural analysis, input values of ground motion (spectral acceleration representation) shall not be less severe than the following:

(*1*) One hundred percent in a principal horizontal direction,

(*2*) Sixty-seven percent in the orthogonal horizontal direction, and

(*3*) Fifty percent in the vertical direction.

(B) The horizontal components shall also be applied in the alternative orthogonal horizontal directions.

(v) If the time history method is used for structural analysis, at least three sets of ground-motion time histories shall be employed. The manner in which the time histories are used shall account for the potential sensitivity of the platform's response to variations in the phasing of the ground-motion records.

(vi) When applicable, effects of soil liquefaction and/or loads resulting from submarine slides or creep, tsunamis, and earthquake motions shall be addressed.

(e) *Loads on steel pile-supported platforms.* The following requirements apply to loads on steel pile-supported platforms and shall be applied together with the requirements in paragraphs (b), (c), and (d) of this section:

(1) The dead load of the platform shall include, as appropriate, the weight in air of the jacket, piling, grout, superstructure modules, stiffeners, decking, piping, heliport, and any other fixed structural part less buoyancy, with due allowance for flooding.

(2) Where appropriate, the deformation loads to be accounted for are those resulting from temperature variations leading to thermal stresses in the platform, and those resulting from soil displacements (e.g., differential settlements or lateral displacements).

(3) Wave load information including the following:

(i) For platforms composed of members having diameters that are negligible in relation to the wave lengths considered, semiempirical formulations accounting for wave-induced drag and inertia forces based on the water particle velocities and accelerations on an undisturbed, incident flow field are acceptable;

(ii) When a method as described in paragraph (e)(3)(i) of this section is used, the wave field shall be described by a defensible wave theory appropriate to the wave heights, wave periods, and water depth at the installation site;

(iii) The coefficients of drag and inertia used in calculating wave loads shall be determined on the basis of model test results, published data, or full-scale measurements appropriate to the structural configuration, surface roughness, and wave field; and

(iv) For platforms composed of members whose diameters are not negligible in relation to the wave lengths considered and for structural configurations that will substantially alter the undisturbed, incident flow field, diffraction forces and the hydrodynamic interaction of structural members shall be taken into account.

(f) *Loads on concrete-gravity platforms.* The following requirements apply to loads on concrete-gravity platforms and shall be applied together with the requirements described in paragraphs (b), (c), and (d) of this section.

(1) The dead load of the platform shall include, as appropriate, the weight in air of the foundation, skirts, columns, superstructure modules, decking, piping, heliport, and any other fixed structural part less buoyancy with due allowance for flooding. Weight calculations based on nominal dimensions and mean values of density are acceptable.

(2) The deformation loads to be accounted for are those due to prestress, shrinkage and expansion, creep, temperature variations, and differential settlements.

(3) Wave load information including the following:

(i) For platforms composed of large gravity bases and one or more columns whose diameters are not negligible in relation to the wave lengths considered, defensible wave-load theories which account for the drag, inertia, and diffraction forces on the platform shall be employed;

(ii) For complex structural configurations, the hydrodynamic interaction of large, immersed structural members shall be addressed;

(iii) When diffraction forces and hydrodynamic interaction are negligible, only semiempirical formulations comparable to those mentioned in paragraphs (e)(3) (i) and (iii) of this section accounting for drag and inertia forces are acceptable; and

(iv) The undisturbed, incident flow field shall be addressed by a defensible wave theory appropriate to the wave heights, wave periods, and water depth at the installation site.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988]

§ 250.136 General design requirements.

(a) *General.* This section specifies the general concepts and methods of analysis to be incorporated in the design of a platform.

(b) *Analytical approaches.* (1) Structural response information including the following:

(i) Methods of analysis employed in association with the specifications of these requirements shall treat geometric and material nonlinearities in a defensible manner. When nonlinear methods of analysis are used to assess collapse mechanisms, it shall be demonstrated that the platform has sufficient ductility to develop the required resistance or structural displacements.

(ii) Where theoretically based analytical procedures covering the platform or parts thereof are unavailable or not well defined, model studies shall be utilized. The acceptability of model studies depends on the procedures employed, including enumeration of the possible sources of errors, the limits of applicability of the model test results, and the methods of extrapolation to full-scale data.

(2) Loading format information including the following:

(i) Either a deterministic or spectral format shall be employed to describe various load components. When a static approach is used, it shall be demonstrated, where appropriate, that the general effects of dynamic amplification were addressed. The influence of waves other than the highest waves shall be investigated for their potential to produce maximum peak stresses resulting from possible resonance with the platform.

(ii) When considering the design earthquake as discussed in § 250.135 of this part, a dynamic analysis shall be performed. A dynamic analysis shall also be performed to assess the effects of environmental or other types of loads if significant dynamic amplification is expected.

(iii) For fatigue analysis, the long-term distribution of the stress range, with proper consideration of dynamic effects, shall be obtained for relevant loadings anticipated during the design life of the platform (see §§ 250.137(c)(6) and 250.138(c)(6) of this part).

(3) Combinations of loading components information including the following:

(i) Loads imposed during and after installation shall be taken into account. Of the various loads described in § 250.135, of this part, those loads to be considered for design shall be combined in a manner consistent with their probability of simultaneous occurrence. However, earthquake loadings shall be applied without consideration of other environmental effects unless conditions at the site necessitate their inclusion. The direction of applied environmental loads shall be that producing the highest possible influences on the platform, considering the platform's orientation and location with respect to bottom topography, direction of fetch, and nearby land masses.

(ii) While it is required to obtain and use those loading components which produce realistic maximum effects on the platform, loading combinations corresponding to conditions after installation shall reflect both operating and design environmental loadings. Sections 250.137, 250.138, and 250.139 of this part give the minimum load combinations to be considered.

(iii) The operating environmental conditions and the maximum tolerable environmental loads during installation shall be specified.

(c) *Overall design considerations.* (1) *Design life.* The design service life of the platform shall be specified as prescribed in § 250.134(c)(2)(iv) of this part.

(2) *Air gap.* An air gap of 5 feet shall be provided between the maximum crest elevation of the design wave (including tidal effects) and the lowest portion of the platform upon which wave forces have not been included in the design. After accounting for the initial and long-term settlements resulting from consolidation and subsidence, the elevation of the crest of the design wave shall be based on the elevation of the mean low-water line, astronomical and storm tides, wave runup, the tilting of the platform, and where necessary, tsunamis.

(3) *Long-term and secondary effects.* The following effects shall be addressed, as appropriate, for the planned platform:

(i) Local vibration due to machinery, equipment, and vortex shedding;

(ii) Stress concentrations at critical joints;

(iii) Secondary stresses induced by large deflections (P-Δ effects);

(iv) Cumulative fatigue;

(v) Corrosion;

(vi) Marine growth; and

(vii) Ice abrasion.

(4) *General arrangement.* The platform and equipment shall be arranged to minimize the potential of structural damage and personal injury resulting from accidents. In this regard, the consequences of the arrangement or placement of the following components and their effects shall be addressed:

(i) Equipment and machinery—noise and vibration,

(ii) High-pressure piping—leakage in closed spaces,

(iii) Lifting devices—dropped loads, and

(iv) Vessel mooring devices—line breakage and tripping quick-release mechanisms.

(5) *Corrosion-protection zones.* Measures taken to mitigate the effects of corrosion as required by §§250.137(d) and 250.138(c)(5) of this part shall be specified and described in terms of the following definitions for corrosion-protection zones:

(i) Submerged zone—that part of the platform below the splash zone,

(ii) Splash zone—that part of the platform between the highest and lowest water levels reached by sea states exceeded for 1 percent of the time annually when superimposed on the highest and lowest levels of tide with due allowance for high and low installation of the platform,

(iii) Atmospheric zone—that part of the platform above the splash zone,

(iv) Ice zone—that part of the platform which can reasonably be expected to come into contact with floating or submerged ice annually.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988]

§ 250.137 Steel platforms.

(a) *Materials*—(1) *General.* (i) This section covers specifications for materials used for the construction of steel pile-supported platforms. Steels shall be suitable for their intended service as demonstrated by testing under relevant service conditions or previous satisfactory performance under service conditions similar to those intended. Steels shall be of good commercial quality, defined by specification, and free of injurious defects.

(ii) Steels shall exhibit satisfactory formability and weldability characteristics and fracture toughness satisfactory for the intended applications. Materials for structural members which are fracture critical or for members which sustain significant tensile stress and whose fracture would pose a threat to the survival of the platform shall have sufficient toughness to guard against brittle fracture. Materials selected for members which are subjected to significant tensile stress shall have toughness suitable to their intended application.

(iii) In cases where principal loads from either service or weld residual stresses are imposed normal to the plate, appropriate precautions shall be taken to avoid lamellar tearing parallel to the plate surface.

(2) Material selection information including the following:

(i) Steels for structural members shall be selected according to criteria that take into account the required yield strength, fracture toughness, service temperature (see paragraph (a)(3) of this section), and intended application;

(ii) Bolts and nuts shall have mechanical and corrosion properties comparable to the structural elements being joined. Materials for bolts and nuts shall be defined by and tested in accordance with material standards compatible with those for the joined structural members;

(iii) When new alloys are used, the adequacy of fracture toughness shall be supported by appropriate fracture tests; and

(iv) When materials other than steel are used for structural purposes, the mechanical and durability properties necessary for their intended function shall be designated, including toughness and fatigue characteristics, where necessary.

(3) *Service temperature.* Service temperature means the temperature that the material is expected to achieve in the operational environment.

(i) For material at or below the waterline, the minimum service temperature shall be the lowest average daily water temperature applicable to the particular depth. For material above the waterline, the minimum service temperature shall be the lowest 1-day average daily atmospheric temperature

over a 10-year period, unless the material is warmed by auxiliary heating.

(ii) In all cases where material temperature is reduced by localized cryogenic storage or other cooling means, such factors shall be accounted for in establishing minimum service temperature.

(4) *Classification of applications.* When considering the welding requirements given in subsequent sections, materials shall be considered as ''Weld Class A'' if the members are critical or special structural elements, ''Weld Class B'' if the members are primary load-carrying members of the platform, or ''Weld Class C'' if the members are secondary structural elements.

(5) *Material designation.* All material employed in platform construction shall be described and designated by a material specification.

(b) *Fabrication and welding*—(1) *General.* (i) Welding shall be performed in accordance with the applicable provisions of the American Welding Society (AWS) publication, AWS D1.1, Structural Welding Code—Steel, or other appropriate welding codes.

(ii) Fabrication other than welding shall be performed in accordance with American Institute of Steel Construction (AISC) publication, Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, or other appropriate codes. The code to be followed during fabrication and construction shall be specified on design documents.

(2) *Welding.* (i) Welding procedures and filler metals shall be selected to produce sound welds, and the filler metal shall have strength and toughness compatible with the base metal. Workmanship shall be in compliance with paragraph (b)(1)(i) of this section.

(ii) Forming processes shall not degrade the base metals below their minimum required properties. A heat treatment shall be employed to provide the required properties, where necessary.

(iii) Misalignment between parallel (abutting) members shall be minimized. Weld size for fillet welds shall be sufficient to compensate for the gap between faying surfaces of the members. Lapped joints shall possess sufficient overlaps. Both edges of an overlap joint shall have continuous fillet welds.

(iv) When arc-air gouging is employed, the carbon buildup and burning of the weld or base metals shall be minimized.

(v) Peening shall not be used for single-pass welds or for the root or cover passes of multipass welds. Peening shall be used only after cleaning of weld passes. Fairing by heating, flame shrinking, or other methods, when applied to Weld Class A or B structural elements, shall be performed without damaging the base metals. Such corrective measures shall be kept to a minimum when treating high-strength steels.

(3) *Quality assurance.* A documented inspection plan shall be prepared and followed and shall cover the following items:

(i) A suitable system for material identification and quality control during all stages of construction,

(ii) Requirements for welding procedures and welder qualifications,

(iii) The extent of weld inspection (including nondestructive examination methods) and the criteria for weld acceptance or rejection, and

(iv) Necessary dimensional tolerances.

(4) *Weld nondestructive examination.* (i) All welds shall be subjected to visual examination. Nondestructive examination shall be conducted to the extent indicated in paragraph (b)(4)(ii) of this section after all forming and postweld heat treatments have been completed. Weld examination procedures shall be adequate to detect delayed weld cracking in cases involving high-strength steels or high-hydrogen welding processes.

(ii) As called for in paragraph (b)(3)(iii) of this section, a plan for nondestructive examination of the welds shall be prepared and followed. The extent of inspection of Weld Classes A and B structural elements shall be consistent with the applications involved. Important welds of Weld Classes A and B structural elements are those inaccessible or very difficult to inspect in service. Important welds shall be subjected to an increased level of nondestructive examination during fabrication.

(iii) If the proportion of unacceptable welds becomes excessive, the frequency of nondestructive examination shall be increased.

(c) *Design and analysis*—(1) *General.* (i) Steel platforms shall be adequately designed and analyzed to withstand the loads to which they are likely to be exposed during their design life. The effects on the platform shall be determined for a minimum set of loading conditions by using a defensible method to ensure that the resulting responses do not exceed the safety criteria appropriate to the methods employed.

(ii) The use of design methods, other than those specifically covered in this section, and their associated safety criteria are allowed if it can be demonstrated that such alternative methods will result in a structural safety level equivalent to that provided by the direct application of these requirements.

(iii) Sections 250.135 and 250.136 of this part shall be consulted regarding definitions and requirements pertinent to the determination of loads and general design requirements.

(2) *Loading conditions.* (i) Appropriate loading conditions that produce the most adverse effects on the platform during and after fabrication and installation shall be considered;

(ii) Loadings corresponding to conditions after installation shall include at least those relating to both the operating and design environmental conditions, combined with other pertinent loads in the following manner:

(A) Operating environmental conditions combined with dead and live loads appropriate to the function and operation of the platform;

(B) Design environmental conditions combined with dead and live loads appropriate to the function and operation of the platform;

(C) Design environmental conditions combined with dead loads and minimum live loads appropriate to the function and operation of the platform; and

(iii) For platforms located in seismically active areas, loads induced by earthquake ground motions shall be combined with dead and live loads appropriate to the operation and function of the platform.

(3) *Methods of design and analysis.* (i) The nature of loads and loading combinations as well as the local environmental conditions shall be considered in the selection of design methods. Methods of analysis and their associated assumptions shall be compatible with the overall design principles.

(ii) Linear, elastic methods (working stress methods) of design and analysis are acceptable if proper measures are taken to prevent general and local buckling failure. Regarding structural instability as a possible mode of failure, the effects of initial stresses and geometric imperfection shall be taken into account.

(iii) Dynamic effects shall be accounted for if the wave energy in the frequency range of the structural resonance frequencies is of sufficient magnitude to produce significant stresses in the platform. The determination of dynamic effects shall be accomplished either by computing the dynamic amplification effects in conjunction with a deterministic analysis or by a random dynamic analysis based on a spectral formulation. In the latter case, the analysis shall be accompanied by a statistical description and evaluation of the relevant input parameters.

(iv) The interaction of the soil with the platform's piles shall be included in the analytical model used to obtain the structural response (see § 250.139(d)(1)(ii) of this part).

(v) For static loads, plastic methods of design and analysis shall be employed only when the properties of the steel and the connections exclude the possibility of brittle fracture and allow for formation of plastic hinges with sufficient plastic rotation capacity and adequate fatigue resistance.

(vi) Whenever plastic analysis is used, it shall be demonstrated that the collapse mode (mechanism) corresponding to the smallest loading intensities has been used for the determination of the ultimate strength of the platform. The effect of buckling and other destabilizing nonlinear effects shall be taken into account in the plastic analysis of platforms with compressive forces. Whenever nonmonotonic or repeating loads are present, it shall be

demonstrated that the structure will not fail by incremental collapse or fatigue.

(vii) Under dynamic loads when plastic strains may occur, the considerations specified in paragraph (c)(3)(v) of this section shall be satisfied and any buckling and destabilizing nonlinear effects shall be taken into account.

(4) *Allowable stresses and load factors.* (i) When the design is based on a working-stress method (see paragraphs (c)(1)(ii) and (c)(3)(ii) of this section), the safety criteria shall be expressed in terms of appropriate basic allowable stresses in accordance with requirements specified in paragraphs (c)(4) (ii) through (vi) of this section.

(ii) For structural members and loadings covered by AISC publication, Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, with the exception of earthquake loadings (see paragraph (c)(4)(v) of this section) and tubular structural members under the combined loading of axial compression and bending, the basic allowable stresses of the members shall be obtained using the AISC specification. For tubular members subjected to the aforementioned interaction, stress limits shall be set in accordance with a defensible formulation.

(iii) Where stresses in members listed in paragraph (c)(4)(ii) of this section are shown to result from forces imposed by the design environmental conditions acting alone or in combination with dead and live loads (see paragraph (c)(2)(ii) of this section), the basic allowable stresses cited in paragraph (c)(4)(ii) of this section, modified by a factor of four-thirds, are permitted for the design environmental load contribution if the resulting structural member sizes are not less than those required for dead and live loads plus operating environmental conditions without the one-third increase in allowable stresses.

(iv) For any two- or three-dimensional stress fields within the scope of the working-stress formulation, the equivalent stress (e.g., the von Mises stress intensity) shall be limited by an appropriate allowable stress less than the yield stress, with the exception of stresses of a highly localized nature. In the latter case, local yielding of the structure is acceptable if it can be demonstrated that such yielding does not lead to progressive collapse of the overall platform and that the general structural stability can be maintained.

(v) When considering loading combinations on individual members or on the overall platform, which include loads defined as accidental (see § 250.135(c)(4) of this part), or in pursuing structural analysis for earthquake loads (see paragraph (c)(2)(iii) of this section), the allowable stress set at a level of the minimum yield or buckling strength of the material shall be considered appropriate.

(vi) Whenever elastic instability, overall or local, may occur before the compressive stresses reach the minimum specified yield strength of the material, appropriate allowable buckling stresses shall govern.

(vii) Whenever the ultimate strength of the platform is used as the basis for the design of its members, the safety factors or the factored loads shall be formulated in accordance with the requirements of AISC publication, Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, or an equivalent code. The capability of the primary structural members to develop their predicted ultimate load capacity shall be demonstrated.

(viii) For details of high-stress concentration, consideration shall be given to safety against brittle fracture and to material quailty-control procedures.

(5) *Structural response to earthquake loads.* (i) Platforms located in seismically active areas shall be designed to possess adequate strength and stiffness to withstand the effects of an earthquake which has a reasonable likelihood of not being exceeded during the lifetime of the structure (see paragraph (c)(2)(iii) of this section) and remain stable during rare motions of greater severity;

(ii) The adequacy of structural strength shall be demonstrated by analysis to verify that no significant structural damage occurs; and

(iii) Platforms shall also possess adequate ductility to withstand a rare intense earthquake.

(6) *Fatigue assessment.* (i) Structural members and joints for which fatigue is a probable mode of failure and for which past experiences are insufficient to ensure safety from possible cumulative fatigue damage shall be analyzed. Emphasis shall be given to joints and members in the splash zone, those that are difficult to inspect and repair after the platform is in service, and those susceptible to corrosion-accelerated fatigue, and

(ii) For structural members and joints which require a detailed analysis of cumulative fatigue damage, the results of the analysis shall indicate a minimum calculated life of twice the design life (see § 250.136(c)(1) of this part) of the platform if there is sufficient structural redundancy to prevent catastrophic failure of the platform as a result of fatigue failure of the member or joint under consideration. If such redundancy does not exist or if the desirable degree of redundancy is significantly reduced as a result of fatigue damages, the results of a fatigue analysis shall indicate a minimum calculated life of three times the design life of the platform.

(d) *Corrosion protection.* All materials shall be protected from the effects of corrosion by a corrosion-protection system. The design of such systems shall take into account the possible existence of stress corrosion, corrosion fatigue, and galvanic corrosion. If the intended sea environment contains unusual contaminants, any special corrosive effects of such contaminants shall also be considered. Protection systems shall be designed in accordance with the National Association of Corrosion Engineers (NACE) publication, NACE Standard RP–01–76, Recommended Practice, Corrosion Control of Steel, Fixed Offshore Platforms Associated With Petroleum Production, or other comparable standards.

(e) *Connection of piles to structure.* The attachment of the jacket structure to the piles shall be accomplished by positive, controlled means. Such attachments shall be capable of withstanding the static and long-term cyclic loadings to which they will be subjected.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988, as amended at 61 FR 60025, Nov. 26, 1996]

§ 250.138 Concrete-gravity platforms.

(a) *General.* (1) This section covers the materials, analysis, design, and construction of reinforced and/or prestressed concrete-gravity platforms.

(2) Materials, structural systems, methods of design, and methods of construction that do not conform to the requirements of this section shall not be used unless it is shown that they will result in a safety level at least equivalent to that provided by the direct application of the requirements of this section.

(b) *Materials*—(1) *General.* All materials shall be selected with due attention to their strength and durability in the marine environment. All material tests shall be performed in accordance with the latest, applicable standards of the American Society for Testing and Materials (ASTM).

(2) *Cement.* (i) Cement shall be equivalent to Type I, II, or III portland cement as specified by ASTM C150, Specification for Portland Cement, or portland-pozzolan cement as specified by ASTM C595, Specification for Blended Hydraulic Cements. However, the suitability of Type III cement to serve its intended function shall be demonstrated.

(ii) The tricalcium aluminate content of the cement shall be such as to enhance the corrosion protection of reinforcing steel without impairing the durability of concrete.

(iii) If oil storage is planned and the oil is expected to contain soluble sulfates in amounts that may impair the durability of concrete, the tricalcium content shall be reduced or a suitable coating employed to protect the concrete.

(3) *Water.* (i) Water used in mixing concrete shall be clean and free from injurious amounts of oils, acids, alkalis, salts, organic materials, or other substances that may be deleterious to concrete or steel.

(ii) If nonpotable water is used, the proportions of materials in the concrete shall be based on test concrete mixes using water from the same source. The strength of mortar test cubes made with nonpotable water shall not be significantly below the strength of similar cubes made with potable water.

(iii) Water for reinforced or prestressed concrete or grout shall not contain chlorides and sulfates in amounts detrimental to the durability of the platform.

(4) *Aggregates.* (i) Aggregates shall conform to the requirements of ASTM C33, Specifications for Concrete Aggregates. Lightweight aggregates conforming to ASTM C330, Specifications for Lightweight Aggregates for Structural Concretes, shall only be permitted if they do not pose durability problems and where they are used in accordance with the applicable provisions of the ACI publication, ACI 318, Building Code Requirements for Reinforced Concrete, plus Commentary.

(ii) Marine aggregates shall be washed with fresh water before use to remove the surface and soluble chlorides and sulfates so that the total chloride and sulfate content of the concrete mix water does not exceed the limits of paragraph (b)(3)(iii) of this section.

(iii) The maximum size of the aggregate shall be such that the concrete can be placed without voids.

(5) *Admixtures.* The admixture shall be shown capable of maintaining essentially the same composition and performance throughout the work as the product used in establishing concrete proportions. Admixtures containing chloride ions shall not be used in prestressed concrete or in concrete containing aluminum embedments.

(6) *Reinforcing and prestressing systems.* (i) Reinforcing and prestressing systems shall conform to the requirements of ACI 318; and

(ii) Structural steel used in composite structures shall conform to the requirements of § 250.137 of this part.

(7) *Concrete.* The concrete shall be designed to ensure sufficient strength and durability. The quality control of concrete shall conform to ACI 318. The mixing, placing, and curing of concrete shall conform to the requirements of paragraph (e) of this section. The water-cement ratio shall be strictly controlled and in no case shall it exceed 0.45.

(8) *Grout for bonded tendons.* (i) Grout for bonded tendons shall conform to ACI 318; and

(ii) The maximum allowable contents of chlorides and sulfates determined in accordance with paragraph (b)(3)(iii) of this section shall also apply to grout mixes.

(9) *Post-tensioning ducts.* Post-dentioning ducts shall conform to the requirements of ACI 318. Ducts and duct splices shall be watertight and grout-tight and shall be of suitable thickness to prevent crushing, deformation, and blockage.

(10) *Post-tensioning anchorages and couplers.* Post-tensioning anchorages and couplers shall conform to the requirements of ACI 318.

(c) *Design requirements*—(1) *General.* (i) The strength of the platform shall be adequate to resist failure of the platform or its components. Among the modes of possible failure that shall be considered are the following:

(A) Loss of overall equilibrium,

(B) Failure of critical sections, and

(C) Instability (buckling).

(ii) Additionally, the following items shall be considered in relation to their potential influences on the platform:

(A) Cracking or spalling,

(B) Deformations,

(C) Corrosion of reinforcement or deterioration of concrete, and

(D) Vibrations.

(2) *Required strength.* The required strength shall conform to requirements of ACI 357R.

(3) *Design strength.* The design strength shall conform to requirements of ACI 318 and ACI 357R.

(4) *Other design requirements.* (i) In considering those items listed in paragraph (c)(1)(ii) of this section, the ability of the platform to withstand unfactored loads in the following combination shall be demonstrated:

$$D+T+L+E_0$$

where L represents the most unfavorable live load; D, the dead load; T, the deformation load; and E_o, the operating environmental load, and

(ii) Crack control design shall be achieved by limiting the crack width in concrete subjected to tension or by limiting the tensile stress in reinforcing steel and prestressing tendons.

(5) *Durability.* (i) Materials, design, construction procedures, and quality

control shall be such as to produce satisfactory durability of platforms in a marine environment, and

(ii) The following items shall be considered in the four zones of exposure (see § 250.136(c)(5) of this part):

(A) Submerged zone—chemical deterioration of the concrete, corrosion of the reinforcement and hardware, and abrasion of the concrete;

(B) Splash zone—freeze-thaw durability, corrosion of the reinforcement and hardware, the chemical deterioration of the concrete, and fire hazards;

(C) Atmospheric zone—freeze-thaw durability, corrosion of reinforcement and hardware, and fire hazards; and

(D) Ice zone—mechanical deterioration resulting from the abrasive action of moving ice.

(6) *Fatigue.* Platforms for which fatigue is a probable mode of failure shall be designed to limit the effects of cumulative material fatigue. The effects of fatigue induced by normal stress and those resulting from shear and bond stress shall be considered. Particular attention shall be given to submerged areas subjected to the low-cycle, high-stress components of the anticipated loading history. If an analysis of the fatigue life is performed in lieu of employing other methods to obviate the possibility of fatigue damage, the calculated fatigue life of the platform shall be at least twice the design life (see § 250.136(c)(1) of this part).

(d) *Analysis and design*—(1) *General.* (i) The analysis of platforms shall be pursued under the assumptions of linearly elastic materials and linearly elastic structural behavior, except as listed in paragraphs (d)(1) (ii) and (iii) of this section.

(ii) The inelastic behavior of concrete, based on the true variation of the modulus of elasticity with stress, shall be taken into account whenever its effect reduces the strength of the platform.

(iii) The geometric nonlinearities and the effect of initial deviation of the platform from the design geometry shall be taken into account whenever their effects reduce the strength of the platform.

(iv) Where appropriate, dynamic effects shall be taken into account. The dynamic response shall be determined by a defensible method that includes the effects of the foundation—platform interaction and the effective mass of the surrounding water.

(v) The material properties used in the analysis shall be based on actual laboratory tests or shall follow the appropriate sections of ACI 318.

(2) *Analysis of frames.* The analysis of frames shall be performed by a defensible method of structural mechanics. The buckling strength of the frame shall be assessed, and the safety against buckling failure shall be ensured to a degree consistent with the requirements in paragraphs (c)(2) and (c)(3) of this section.

(3) *Analysis of plates, shells, and folded plates.* The buckling strength of these plates shall be determined and a sufficient safety margin against instability shall be ensured.

(4) *Determination of deflections.* Deflections shall be determined by a defensible method. In addition to the immediate (instantaneous) deflections, the long-term deflections due to creep shall be accounted for.

(5) *Analysis and design for bending and axial loads.* The provisions of ACI 318 shall apply to the analysis and design of members subject to flexure or axial loads or to combined flexure and axial loads.

(6) *Analysis and design for shear and torsion.* The provisions of ACI 318 shall apply to the analysis and design of members subject to shear or torsion or to combined shear and torsion.

(7) *Analysis and design of prestressed concrete.* The analysis and design of prestressed concrete members and structures shall comply with ACI 318. In addition, the safety requirements of paragraph (c) of this section shall be satisfied.

(8) *Details of reinforcement and prestressing systems.* Details of reinforcement and prestressing systems shall conform to the requirements of ACI 318 with special attention given to the fatigue resistance and ultimate behavior of offshore structures.

(9) *Minimum reinforcement.* The minimum amount of reinforcement shall conform to the requirements of ACI 318. Additionally, sufficient reinforcement shall be provided to control crack

growth, especially at surfaces exposed to severe hydraulic pressures.

(10) *Concrete cover of reinforcement and prestressing tendons.* The concrete cover of reinforcement and prestressing tendons shall be sufficient to provide for corrosion protection of the steel.

(11) *Seismic analysis.* A dynamic analysis shall be performed to determine the response of the platform to design-earthquake loading. The platform shall be designed to withstand this loading without damage. In addition, a ductility check shall also be performed to ensure that the platform has sufficient ductility to experience deflections more severe than those resulting from the design-earthquake loading without the collapse of the platform or its foundation or any primary structural component.

(12) *Seismic design.* The design of structural members and details of platforms subjected to seismic loading shall ensure maximum ductility at critically loaded sections.

(e) *Construction*—(1) *General.* (i) Construction methods and workmanship shall conform to the provisions of ACI 318 and to the following requirements.

(ii) At each stage of construction, i.e., fabrication, initial flotation, towing, and installation in situ, the forces acting on the platform shall be kept within the safety limits listed in paragraph (c) of this section. Appropriate static and/or dynamic analysis shall be performed for the operating loading conditions of each of the construction operations mentioned above. Buoyancy and stability shall be considered during all phases of construction.

(2) *Mixing, placing, and curing of concrete.* (i) Mixing of concrete shall conform to the requirements of ACI 318 and ASTM C94, Specification for Ready Mixed Concrete;

(ii) When concreting in cold weather, the temperature of the fresh concrete shall be maintained sufficiently above freezing until the process of hardening is well in progress;

(iii) In hot weather, the temperature of the fresh concrete shall be controlled so that it does not impair attainment of the desired strength and durability;

(iv) The methods for curing concrete shall ensure maximum compressive and tensile strength, durability, and a minimum of cracking; and

(v) The location and workmanship of construction joints shall not impair the strength, crack resistance, and watertightness of the platform.

(3) *Reinforcement.* (i) Reinforcement shall be free from loose rust, grease, oil, deposits of salt, or any other material that may adversely affect the strength, durability, or bond of the reinforcement. The specified cover of reinforcement shall be maintained accurately. The cutting, bending, and fixing of reinforcement shall ensure that it is correctly positioned and rigidly held.

(ii) The welding of reinforcement shall conform to the requirements of AWS publication, AWS D1.4, Structural Welding Code— Reinforcing Steel.

(4) *Prestressing tendons, ducts, and grouting.* (i) Steps shall be taken to ensure that the achieved prestressing force is that specified in the design.

(ii) Tendons and ducts shall be in a condition that ensures the required strength, durability, and bond.

(iii) The grouting procedures shall produce the required bond strength of the tendons and provide permanent corrosion protection for the tendons. Anchorages shall also be protected adequately against corrosion.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60025, Nov. 26, 1996]

§ 250.139 Foundation.

(a) *General*—(1) *Coverage.* Soil investigations, design considerations for the supporting soil, and the influence of the soil on the foundation structure are addressed in this section, including criteria for the strength and deformation characteristics of the foundation employed by both pile founded and gravity platforms.

(2) *Guidelines.* (i) The degree of design conservatism shall reflect prior experience under similar conditions, the manner and extent of data collection, the scatter of design data, and the consequences of failure;

(ii) For cases where the limits of applicability of any method of calculation employed are not well defined or where the soil characteristics are quite variable, the use of more than one method of calculation or a parametric

study of the sensitivity of the important design variables shall be considered, and

(iii) A listing of design parameters, necessary calculations, and test results shall be retained by the designer.

(b) *Site investigation*—(1) *General.* (i) The actual extent, depth, and degree of precision to be obtained in the site investigation program shall reflect the type and intended use of the platform, characteristics of the site, similarity of the area based on previous site studies or platform installations as well as the consequences of a failure of the foundation. The site investigation program shall generally consist of three major phases as follows:

(A) Shallow hazards (see paragraph (b)(2) of this section) to obtain relevant geophysical data.

(B) Geological survey (see paragraph (b)(3) of this section) to obtain data of a regional nature concerning the site.

(C) Subsurface investigation and testing (see paragraph (b)(4) of this section) to obtain the necessary geotechnical data. The results of these investigations shall be the basis for the additional site related studies specified in paragraph (b)(5) of this section.

(ii) A complete site-investigation program shall be furnished for each platform. The positioning devices used on the vessel employed in the site investigation as well as those used during the installation of the platform shall have sufficient accuracy to ensure that the data obtained are pertinent to the actual final location of the platform.

(2) *Shallow hazard survey*. (i) Consistent with the objectives of paragraph (b)(1)(i) of this section, a high-resolution or acoustic-profiling survey shall be performed to obtain information on the conditions existing at and near the surface of the seafloor; and

(ii) The information to be obtained from this survey shall include the following items, as appropriate, for the planned platform:

(A) Contours of the sea bed,

(B) Presence of any seafloor surface or near-surface anomaly or obstructions which would adversely affect platform installation at the site,

(C) Shallow faults,

(D) Gas seeps,

(E) Slump blocks,

(F) Occurrence of shallow gas, and

(G) Ice scour of seafloor sediments.

(3) *Geological survey*. (i) Background geological data shall be obtained to provide regional information that can affect the design and siting of the platform. The data shall be considered in planning the subsurface investigation.

(ii) Where necessary, the seismic activity at the site shall be assessed. Fault zones, the extent and geometry of faulting, and attenuation effects of conditions in the vicinity of the site shall be identified.

(iii) For platforms located in a producing area, the possibility of seafloor subsidence shall be considered.

(4) *Subsurface investigation and testing.* (i) The primary objective of the subsurface investigation and testing program shall be the attainment of reliable geotechnical data concerning the stratigraphic and engineering properties of the soil. These data shall be used to properly design the foundation to the desired structural safety level.

(ii) The subsurface investigation and soil testing program shall consist of adequate in situ testing, boring, and sampling to examine all important soil and rock strata. The testing program shall reveal the necessary strength, classification, and deformation properties of the soil. Further tests, as needed, shall describe the dynamic characteristics of the soil.

(iii) At least one borehole having a minimum depth of the anticipated length of the pile plus a zone of influence shall be drilled at the installation site for a pile-supported platform. Previously gathered borehole data may be used on a case-by-case basis, when approved by the Regional Supervisor. The zone of influence shall be sufficient to ensure that punch through failures will not occur. Additional boreholes of a lesser depth shall be required by the Regional Supervisor if discontinuities in the soil are indicated to exist in the area of the platform.

(iv) For a gravity-type platform foundation, the required depth of the borehole shall be equal to at least the depth of the zone of influence which the structure imposes on the supporting soil. Where possible, in situ tests shall

be performed to a depth that will include the anticipated shearing failure zone.

(v) When samples from the field are sent to a laboratory for further testing, they shall be packed carefully and accurately labeled, and the results of visual inspections shall be recorded.

(vi) A summary report showing the results of the soil testing program shall be prepared. The report shall describe briefly the various field and laboratory test methods employed and shall indicate the applicability of these methods as they relate to the quality of the sample, the type of soil, and the anticipated design application.

(vii) The engineering properties of the soil to be used in the design shall be listed for each stratum. The selected design properties shall specify the uncertainties inherent in the overall testing program and in the reliability and applicability of the individual test methods.

(5) *Additional requirements.* Based on the results of the overall site investigation program, studies shall be performed, as applicable, to assess the following effects of the installed platform:

(i) Scouring potential of the seafloor,

(ii) Hydraulic instability and the occurrence of sand waves,

(iii) Instability of slopes in the area where the platform is to be placed,

(iv) Liquefaction and/or possible reduction of soil strength due to increased pore pressures, and

(v) Degradation of subsea permafrost layers.

(c) *Foundation design requirements*—(1) *General.* (i) The loadings used in the design of the foundation shall include those defined in paragraph (c)(6)(ii) of this section.

(ii) Foundation displacements shall be evaluated to ensure that they are within limits that do not impair the intended function and safety of the platform.

(iii) The soil and the platform shall be considered as an interactive system, and the results of the analysis as required in paragraphs (c)(2) through (c)(6) of this section shall be evaluated from this point of view.

(2) *Cyclic loading effects.* Evaluation of the short-term and long-term effects of cyclic loading with respect to changes in soil characteristics, whether caused by conditions during installation, seismic activity, or storms, shall be accomplished by using defensible methods.

(3) *Scour.* (i) For unprotected foundations, the depth and lateral extent of scouring, as determined in the site investigation program, shall be accounted for in design; and

(ii) If scour is not accounted for in design, either effective protection shall be furnished soon after the installation of the platform or frequent visual inspection shall be carried out, particularly after major storms.

(4) *Settlements and displacements.* (i) Based on the type and function of the platform, tolerable limits shall be established for settlements and lateral deflections. Due consideration shall be given to the effect of these movements on risers, pilings, and other components which interact with the platform;

(ii) Maximum allowable values of platform movements, as limited by these structural considerations or overall platform stability, shall be considered in the design.

(5) *Dynamic considerations.* (i) For dynamic-loading conditions, a defensible method shall be employed to simulate the interactive effects between the soil and the platform, and

(ii) The evaluation of the dynamic response of the platform shall account for, as appropriate, the nonlinear and inelastic characteristics of the soil, the possible deterioration of strength, the increased or decreased damping due to cyclic soil loading, and the influence of nearby platforms.

(6) *Loading conditions.* (i) Loadings producing the worst effects on the foundation during and after installation shall be addressed; and

(ii) In-place platform loadings to be checked shall include at least those relating to both the operating and design environmental conditions, combined in accordance with the following:

(A) Operating environmental conditions with dead and live loads appropriate to the function and operation of the platform,

(B) Design environmental conditions with dead and live loads appropriate to

the function and operation of the platform, and

(C) Design environmental conditions with dead and minimum live loads appropriate to the function and operation of the platform.

(d) *Pile foundations*—(1) *General.* The following requirements apply to pile-founded platforms. Pertinent parts of these requirements dealing with steel design shall be consulted regarding the design of the steel piles.

(i) In the design of individual piles and piles in a group, the effects of axial, bending, and lateral loads shall be addressed.

(ii) The design of a pile shall reflect the interactive behavior between the soil and the pile, between the pile and the platform, and between piles in a group.

(iii) Methods of pile installation shall be consistent with the type of soil at the site and the installation equipment available. If unexpectedly high-driving resistance or other conditions lead to a failure of the pile to reach the desired penetration, the pile's capacities shall be reevaluated by considering the actual installation situation.

(iv) Pile driving shall be performed and supervised by qualified and experienced personnel. Driving records which include such information as blowcounts and estimated hammer performance and stoppages shall be retained.

(v) Where necessary, the effects of bottom instability in the vicinity of the platform shall be assessed.

(2) *Axial piles.* (i) For piles in compression, the axial capacity shall be considered to consist of the skin friction, Q_f, developed along the length of the pile and the end bearing, Q_p, at the tip of the pile. The various parameters needed to evaluate Q_f and Q_p shall be predicted by using a defensible analytical method that employs reliably obtained soil data consistent with the prediction method selected. The acceptability of any method used to predict the components of pile resistance shall be demonstrated by showing satisfactory performance of the method under conditions similar to those existing at the actual site.

(ii) The results of the dynamic pile driving analysis alone shall not be used to predict the axial load capacity of a pile.

(iii) For piles driven through clay, the estimated skin friction developed over any increment of the pile surface shall not exceed the shear strength of the clay.

(iv) The capacity of the internal plug of an open-ended pile shall be considered since it may limit the estimated end bearing to the pile.

(v) When combining side friction and end-bearing effects in determining axial pile capacity, the load deflection response of the soil-pile system shall be addressed.

(vi) For piles subjected to pullout loads, the contribution of the end resistance of the pile to its axial capacity shall not be considered. The possible variation of predicted pile-skin friction between the compressive and tensile modes of the axial-pile loading shall be considered.

(3) *Laterally loaded piles.* (i) In evaluating the pile's behavior when acted upon by lateral loadings, the combined load deflection characteristics of the soil and the pile and the pile and the platform shall be addressed.

(ii) The representation of the soil's lateral displacement when it is subjected to lateral loads shall adequately reflect the deterioration of the lateral load capacity when the soil is subjected to cyclic loading.

(iii) The description of the lateral load versus displacement characteristics for the various soil strata shall be based on constitutive data obtained from suitable soil tests. The use of empirical methods to provide the description of the soil's lateral response shall be permitted if such methods are documented.

(iv) Where applicable, the rapidly deteriorating cyclic lateral load capacity of stiff clays, especially those exhibiting the presence of a secondary structure, shall be addressed in the design.

(v) Calculation of pile deflection and stress induced by lateral loads shall account for the nonlinear interaction between the soil and the pile.

(4) *Pile groups.* Where applicable, the effects of close spacing on the load and deflection characteristics of pile groups shall be determined. The allowable load for a group, both axial and

lateral, shall not exceed the sum of the apparent individual pile allowable loads.

(5) *Plastic analysis.* When the design of a platform is based on the formation collapse mechanisms associated with a plastic analysis method, influence of the soil's support on the pile shall be addressed.

(e) *Gravity platforms foundations*—(1) *General.* The following requirements apply to soil foundations for gravity platforms. Section 250.138 of this part shall be consulted regarding the design of the base slab.

(i) The influence of hydraulic and slope instability, if any, shall be determined for the structural loading cases that include the design environmental loading.

(ii) The effects of adjacent platforms and the variation of soil properties in the horizontal direction shall be considered, as appropriate.

(iii) The stability of the foundation with regard to bearing and sliding failure modes shall be investigated by employing the soil shear strengths determined with consideration of paragraphs (b)(4) and (c)(2) of this section.

(iv) When an underpressure or overpressure is experienced by the seafloor under the platform, provisions shall be made to prevent piping that could impair the integrity of the foundation.

(v) Initial, consolidation, and secondary settlements, as well as permanent horizontal displacements, shall be determined.

(vi) If the intended site is not level, the predicted tilt of the overall platform shall be based on the average bottom slope of the seafloor and the tolerance of the measuring device used in the site-investigation program. Differential settlement shall also be calculated and the tilting of the platform caused by this settlement shall be combined with the predicted structural tilt of the overall platform. Any increased loading effects caused by tilting of the platform shall be addressed in stability requirements specified for the foundation.

(2) *Stability.* (i) The bearing capacity and lateral resistance shall be calculated by considering the most unfavorable combination of loads. The long-term redistribution of bearing pressures under the base slab shall be considered to ensure that the maximum edge pressures are used in the design of the base.

(ii) The lateral resistance of the platform shall be investigated considering various potential shearing planes. The presence of any soft layers shall require special consideration.

(iii) Calculations for overturning moment and vertical forces induced by the passage of a wave shall include the vertical pressure distribution across the top of the foundation and along the seafloor. The foundation shall not lose contact with the soil due to uplift created by the maximum overturning moment.

(iv) The capacity of the foundation to resist a deep-seated bearing failure shall be analyzed.

(v) Where present, the additional effects of penetrating walls or skirts that transfer vertical and lateral loads to the soil shall be investigated for their contribution to bearing load capacity and lateral resistance.

(3) *Soil reaction on the platform.* (i) For conditions during and after installation, the reaction of the soil against all structural members seated on or penetrating into the seafloor shall be determined and accounted for in the design of these members.

(ii) The distribution of soil reactions shall be based on the results obtained in paragraphs (b)(2) and (b)(4) of this section, and the calculations of soil reactions shall account for any deviation from a plane surface, the load-deflection characteristics of the soil, and the geometry of the platform base.

(iii) Where applicable, effects of local soil stiffening, nonhomogeneous soil properties, and boulders and other obstructions shall be addressed in the design. During installation, the possibility of local contact pressures due to irregular contact between the base and the seafloor shall be considered. Contact pressures shall be added to the hydrostatic pressure.

(iv) The penetration resistance of structural elements projecting into the seafloor below the foundation structure shall be analyzed. The design of the ballasting system shall reflect uncertainties associated with achieving the required penetration of the platform.

§ 250.140 Marine operations.

(a) *General*—(1) Marine operations means all activities necessary for the transportation and installation of a platform from the time it enters the marine environment until it is fixed in place at its final destination. Marine operations generally include such activities as follows:

(i) Lifting and mooring,

(ii) Loadout or initial flotation,

(iii) Fabrication afloat,

(iv) Towing,

(v) Launching and uprighting,

(vi) Submergence,

(vii) Pile installation, and

(viii) Final field erection.

(2) The requirements of this section apply to all platforms covered by this subpart, regardless of structural type or material of construction.

(b) *Objective.* The structural strength and integrity of a platform shall not be reduced or otherwise jeopardized by the performance of the activities required to install the platform on site. The type and magnitude of loads and load combinations to which a platform will be exposed during marine operations shall be the subject of an analysis pursuant to paragraph (c) of this section, except where the use of proven and well-controlled methods of fabrication and installation are proposed and justified. Sufficient equipment shall be provided to ensure installation of the platform in a safe and well-controlled manner.

(c) *Analysis.* (1) Analyses shall be performed to determine the type and magnitude of the loads and load combinations to which the platform will be exposed during the performance of marine operations.

(2) Analyses shall be performed to ensure that the structural design is sufficient to withstand the type and magnitude of the loads and load combinations determined, in accordance with paragraph (c)(1) of this section, without loss or degradation of structural integrity.

(3) Analyses shall be performed to ensure that the platform or its means of support has sufficient hydrostatic stability and reserve buoyancy to allow for successful execution of all phases of marine operations.

§ 250.141 Inspection during construction.

(a) *General*—(1) *Coverage.* All pile-supported and gravity platforms covered by this subpart shall be inspected during the construction phase. Additional requirements for steel pile-supported platforms are contained in paragraph (b) of this section, and additional requirements pertaining to concrete-gravity platforms are contained in paragraph (c) of this section. The phases of construction subject to inspection include material manufacture, fabrication, loadout, transportation, positioning, installation, and final field erection.

(2) *Objective.* Inspections during construction are to verify that the platform is constructed in accordance with the approved construction plan. Any unusual or innovative application of materials or methods of construction not adequately covered by the requirements of this section shall receive special attention during compliance inspections relevant to its effect on the integrity of the platform.

(3) *Remedial action.* If construction inspection results reveal that materials, procedures, or workmanship deviate significantly from the approved design, remedial action shall be taken.

(4) *Identification of materials.* The origin of materials used in the platform and the results of relevant material tests for all significant structural materials shall be retained and made readily available for inspection by MMS representatives during all stages of construction. Records shall be kept of the locations throughout the platform of the various heat numbers for such materials.

(b) *Steel pile-supported platforms*—(1) *Scope.* Inspections of steel pile-supported platforms shall address the following topics, as appropriate:

(i) Material quality and forming,

(ii) Welder and welding procedure qualifications,

(iii) Weld inspection,

(iv) Tolerances and alignments, and

(v) Corrosion-control systems.

(2) *Material quality and forming.* Inspection shall verify that all materials employed are of good quality and suitable for their intended service as specified in the approved design. Inspection

shall ensure the compliance of materials to the relevant material standards selected in the design of the platform. Inspection shall ensure that formed members satisfy the dimensional tolerances listed in the design.

(3) *Welder and welding-procedure qualifications.* (i) Welders shall be tested and possess a current welder's certification.

(ii) All welding procedures to be employed shall be tested and certified for the production of satisfactory welds. Welding procedures previously tested and certified shall be considered prequalified.

(4) *Weld inspection.* (i) Inspection shall include, but not be limited to, visual inspection of all welds and representative magnetic particle or dye penetrant inspection of welds of Weld Classes A and B materials (see § 250.137(a)(4) of this part) not subjected to ultrasonic or radiographic inspection. The extent of ultrasonic or radiographic inspection shall be specified and shall emphasize, but not be confined to, welds of Weld Class A materials.

(ii) The extent and methods of inspection shall be consistent with the classification of applications (see § 250.137(a)(4) of this part) of the area being examined.

(iii) Any welding not meeting the acceptance criteria specified in the inspection plan shall be rejected and appropriate remedial action taken.

(5) *Tolerances and alignments.* Overall dimensional tolerances, forming tolerances, and local alignment tolerances shall be commensurate with those considered in developing the structural design. Inspections shall ensure that the dimensional tolerance criteria are being met. Out of roundness of structural elements for which buckling is the anticipated mode of failure shall receive individual inspection.

(6) *Corrosion-control systems.* Corrosion-control systems employed on the platform shall be inspected to ensure that they are installed as specified in the approved design. Inspection shall ensure that proper protection against galvanic effects, especially in locations where nonferrous materials are used in conjunction with steel, has been provided in the corrosion-control system.

(7) *Additional inspection items.* (i) The provisions of paragraphs (b)(2) through (b)(6) of this section relate only to matters directly affecting the onshore construction phases of the platform. Other items relating to the onshore construction site and the construction phases from loadout to final erection shall also be performed.

(ii) The construction site shall be inspected to ensure that adequate consideration has been given to the following items:

(A) Support of the platform during construction,

(B) Employment of a sufficient number of certified welders and inspectors to maintain an adequate quality of work, and

(C) Weathertight storage of welding consumables under conditions specified by their manufacturers.

(iii) Inspection shall verify that the following operations have been accomplished in a manner conforming to approved plans or drawings:

(A) Loadout,

(B) Tie down,

(C) Positioning at the site,

(D) Installation (see § 250.139(d)(1)(iv) of this part for piles), and

(E) Final field erection.

(iv) To determine if overstressing of the platform during transportation has occurred, towing records shall be reviewed to ascertain if conditions during towing operations exceeded those employed in the analyses required by § 250.140(c) of this part.

(v) When the inspections indicate that overstressing has occurred during loadout, transportation, or installation, the affected parts of the platform shall be surveyed to determine the extent of actual damage, if any. Where necessary, a reevaluation of the structural capacity shall be carried out, considering the results of the survey.

(8) *Records.* The following construction records shall be compiled, retained, and made available for inspection by MMS representatives:

(i) Mill certificates,

(ii) Weld-procedure qualification records,

(iii) Weld inspection records,

(iv) Dimensional tolerance reports,

(v) Towing records, and

(vi) Pile driving records.

(c) *Concrete-gravity platforms*—(1) *Scope.* Inspection of concrete-gravity platforms shall address the following topics, as appropriate:

(i) Preparation for concrete production and placement;

(ii) Batching, mixing, and placing concrete;

(iii) Form removal and concrete curing;

(iv) Pretensioning and grouting;

(v) Joints; and

(vi) Finished concrete.

(2) *Preparation for concrete production and placement.* (i) Inspection shall ensure that the pertinent physical properties of cement, reinforcing steel, prestressing tendons, and appurtenances comply with those specified in the approved design.

(ii) Forms and shoring supporting the forms shall be inspected to ensure that they are adequate in number and type and are located correctly.

(iii) The dimensional tolerances of the forms shall be inspected to ensure that the finished dimensional tolerances are comparable to those allowed for in the approved design.

(iv) Reinforcing steel, prestressing tendons, post-tensioning ducts, anchorages, and any other embedded steel shall be inspected, as appropriate, for size, bending, spacing, location, firmness of installation, surface condition, vent locations, proper duct coupling, and duct capping.

(3) *Batching, mixing, and placing concrete.* (i) Inspections shall be performed to ensure that the procedures for the production and placement of concrete provide a well-mixed and well-compacted concrete. The procedures shall also limit segregation, loss of material, contamination, and premature initial set during all operations.

(ii) Inspection shall verify that the mix components of each batch of concrete are properly proportioned and within allowable variations specified in the approved design. Inspection shall ensure that the water/cement ratio of each batch is within the limit specified in § 250.138(b)(7) of this part.

(iii) Aggregate gradation, cleanliness, moisture content, and unit weight shall be tested. The frequency of testing shall be determined taking into account the uniformity of the supply source, volume of concrete used, and variations of atmospheric conditions.

(iv) Mix water shall be tested for purity following specified methods and schedules.

(v) Testing during the production of concrete shall be performed to monitor, as a minimum, the following concrete qualities:

(A) Consistency,

(B) Air content, and

(C) Strength.

(4) *Form removal and concrete curing.* (i) Inspection shall ensure that forms and form supports are not removed until the platform has attained sufficient strength to bear its own weight, construction loads, and anticipated environmental loads without undue deformation and that they are removed according to schedule.

(ii) Inspection shall ensure that curing of concrete is accomplished in accordance with the provisions of a predetermined procedure.

(iii) Where the construction procedures require the submergence of recently placed concrete, inspection shall ensure that methods for protecting the concrete from the effects of salt water are properly executed.

(5) *Pretensioning and grouting.* (i) Inspection shall verify that the sequence of tendon tensioning and the resulting elongation and force are in accordance with provisions specified in the approved design.

(ii) Pretensioning or post-tensioning stress shall be determined by measuring both tendon elongation and tendon force. Inspection shall verify that the variation of measurements does not exceed a specified amount.

(iii) Inspection shall verify that grout mix proportions and ambient conditions during mixing are in accordance with provisions designated in the approved design. Tests for grout, viscosity expansion, bleeding, compressive strength, and setting time shall be performed to ensure compliance with design requirements. Procedures shall be observed to ensure that ducts are completely filled.

(iv) Anchorages shall be inspected to ensure that they are located and sized

as specified in the design and are provided with adequate cover to mitigate the effects of corrosion.

(6) *Joints.* Where appropriate, leak testing of construction joints shall be performed by using specified procedures. When deciding which joints to inspect, consideration shall be given to the hydrostatic head on the subject joint during normal operation, the consequence of a leak at the subject joint, and the ease of repair once the platform is in service.

(7) *Finished concrete.* (i) The surface of the hardened concrete shall be completely inspected for cracks, honeycombing, popouts, spalling, and other surface imperfections.

(ii) The platform shall be examined by using a calibrated rebound hammer or a similar nondestructive examination device. Inspection shall verify that the results of surface inspection, cylinder strength test, or nondestructive examination are in accordance with the approved design criteria.

(iii) The completed sections of the platform shall be checked for compliance to specified design tolerances of thickness and alignment and, to the extent practicable, the location of reinforcing and prestressing steel and post-tensioning ducts.

(8) *Additional inspection items.* (i) While the provisions of paragraphs (c)(2) through (c)(7) of this section relate only to some matters directly affecting the onshore or nearshore construction phases of the platform, other items relating to such phases and from loadout to final erection shall also be considered.

(ii) Inspection shall ensure that adequate consideration has been given the following items:

(A) Support of the structure during construction,

(B) Employment of a sufficient number of competent workmen and inspectors to maintain an adequate quality of work,

(C) Storage of cement and prestressing tendons in weathertight areas,

(D) Storage of admixtures and epoxies according to manufacturers' specifications, and

(E) Storage of aggregates to limit segregation, contamination by deleterious substances, and moisture variations within the stockpile.

(iii) Inspection shall verify that the following operations, as applicable to the planned platform, have been accomplished in a manner conforming to approved plans or drawings developed for these operations:

(A) Loadout,

(B) Towing arrangements,

(C) Positioning at the site,

(D) Installation, and

(E) Final field erection.

(iv) To determine if overstressing of the platform during transportation has occurred, towing records shall be reviewed to ascertain if conditions during the towing operations exceeded those employed in the analyses required by § 250.140(c) of this part.

(9) *Records.* The following construction records shall be compiled, retained, and made available for inspection by MMS representatives:

(i) Material certificates and test reports;

(ii) Tensioning and grouting records;

(iii) Concreting records including weight, moisture content, mix proportions, test methods and results, ambient conditions during the pour, and test equipment calibration data;

(iv) Deviations from design or fabrication specifications and repairs carried out;

(v) Towing records; and

(vi) Data on initial structural settlements.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988]

§ 250.142 Periodic inspection and maintenance.

(a) All platforms installed in the OCS shall be inspected periodically in accordance with the provisions of API RP 2A, section 14, Surveys. However, use of an inspection interval which exceeds 5 years shall require prior approval by the Regional Supervisor. Proper maintenance shall be performed to assure the structural integrity of the platform as a workbase for oil and gas operations.

(b) A report shall be submitted annually on November 1 to the Regional Supervisor stating which platforms have been inspected in the preceding 12

months, the extent and area of inspection, and the type of inspection employed, i.e., visual, magnetic particle, ultrasonic testing. A summary of the testing results shall be submitted indicating what repairs, if any, were needed and the overall structural condition of the platform.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 51415, Dec. 14, 1990]

§ 250.143 Platform removal and location clearance.

(a) The lessee shall remove all structures in a manner approved by the Regional Supervisor to assure that the location has been cleared of all obstructions to other activities in the area.

(b) All platforms (including casing, wellhead equipment, templates, and piling) shall be removed by the lessee to a depth of at least 15 feet below the ocean floor or to a depth approved by the Regional Supervisor based upon the type of structure or ocean-bottom conditions.

(c) The lessee shall verify by appropriate means that the location has been cleared of all obstructions. The results of the location clearance survey shall be submitted to the Regional Supervisor by means of a letter from the company performing the work certifying that the area was cleared of all obstructions, the date the work was performed, the extent of the area surveyed, and the survey method used.

§ 250.144 Records.

The lessee shall compile, retain, and make available to Minerals Management Service representatives for the functional life of all platforms, the as-built structural drawings, the design assumptions and analyses, a summary of the nondestructive examination records, and the inspection results from platform inspections required by § 250.142 of this part.

Subpart J—Pipelines and Pipeline Rights-of-Way

§ 250.150 General requirements.

(a) Pipelines and associated valves, flanges, and fittings shall be designed, installed, operated, maintained, and abandoned to provide safe and pollution-free transportation of fluids in a manner which does not unduly interfere with other uses in the Outer Continental Shelf (OCS).

(b) An application shall be submitted to the Regional Supervisor and approval obtained prior to the installation, modification, or abandonment of a pipeline which qualifies as a lease term pipeline (see § 250.151, Definitions) and prior to the installation of a right-of-way pipeline or the modification or relinquishment of a pipeline right-of-way.

(c) A pipeline which qualifies under the Department of the Interior's (DOI) jurisdiction (DOI pipeline) shall meet the requirements of § 250.150 through 250.158 of this subpart. The DOI's exclusive jurisdiction with respect to pipeline activities extends upstream from the outlet flange at each facility where produced hydrocarbons are first separated, dehydrated, or otherwise processed to each production well in the OCS. In addition, those pipelines necessary for the development of a lease, e.g., gas-lift gas or supply pipelines, are under DOI's exclusive jurisdiction.

(d) A pipeline which qualifies as a right-of-way pipeline (see § 250.151, Definitions) shall not be installed until a right-of-way has been requested and granted in accordance with this subpart.

(e)(1) The Regional Supervisor may suspend any pipeline operation upon a determination by the Regional Supervisor that continued activity would threaten or result in serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, mineral deposits, or the marine, coastal, or human environment.

(2) The Regional Supervisor may also suspend pipeline operations or a right-of-way grant if the Regional Supervisor determines that the lessee or right-of-way holder has failed to comply with a provision of the Act or any other applicable law, a provision of these or other applicable regulations, or a condition of a permit or right-of-way grant.

(3) The Secretary of the Interior (Secretary) may cancel a pipeline permit or right-of-way grant in accordance with 43 U.S.C. 1334(a)(2). A right-

of-way grant may be forfeited in accordance with 43 U.S.C. 1334(e).

§ 250.151 Definitions.

Terms used in this subpart shall have the meanings given below:

Lease term pipelines are those pipelines owned and operated by a lessee or operator and are wholly contained within the boundaries of a single lease, unitized leases, or contiguous (not cornering) leases of that lessee or operator.

Pipelines are the piping, risers, and appurtenances installed for the purpose of transporting oil, gas, sulphur, and produced water. (Piping confined to a production platform or structure is covered in Subpart H, Production Safety Systems, and is excluded from this subpart.)

Right-of-way pipelines are those pipelines which—

(a) Are contained within the boundaries of a single lease or group unitized leases but are not owned and operated by the lessee or operator of that lease or unit,

(b) Are contained within the boundaries of contiguous (not cornering) leases which do not have a common lessee or operator,

(c) Are contained within the boundaries of contiguous (not cornering) leases which have a common lessee or operator but are not owned and operated by that common lessee or operator, or

(d) Cross any portion of an unleased block(s).

§ 250.152 Design requirements for DOI pipelines.

(a) The internal design pressure for steel pipe shall be determined in accordance with the following formula:

$$P = \frac{2(S)(t)}{D} \quad X(F)(E)(T)$$

For limitations see section 841.121 of American National Standards Institute (ANSI) B31.8 where—

P=Internal design pressure in pounds per square inch (psi).

S=Specified minimum yield strength, in psi, stipulated in the specification under which the pipe was purchased from the manufacturer or determined in accordance with section 811.253(h) of ANSI B31.8.

D=Nominal outside diameter of pipe, in inches.

t=Nominal wall thickness, in inches.

F=Construction design factor of 0.72 for the submerged component and 0.60 for the riser component.

E=Longitudinal joint factor obtained from Table 841.1B of ANSI B31.8. (See also section 811.253(d)).

T=Temperature derating factor obtained from Table 841.1C of ANSI B31.8.

(b)(1) Pipeline valves shall meet the minimum design requirements of American Petroleum Institute (API) Spec 6A, API Spec 6D, or the equivalent. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those standards.

(2) Pipeline flanges and flange accessories shall meet the minimum design requirements of ANSI B16.5, API Spec 6A, or the equivalent. Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(3) Pipeline fittings shall have pressure-temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting shall at least be equal to the computed bursting strength of the pipe.

(c) The maximum allowable operating pressure (MAOP) shall not exceed the least of the following:

(1) Internal design pressure of the pipeline, valves, flanges, and fittings;

(2) Eighty percent of the hydrostatic pressure test (HPT) of the pipeline; or

(3) If applicable, the MAOP of the receiving pipeline when the proposed pipeline and the receiving pipeline are connected at a subsea tie-in.

(d) If the maximum source pressure (MSP), exceeds the pipeline's MAOP, redundant safety devices meeting the requirements of section A9 of API RP 14C shall be installed and maintained. Pressure safety valves (PSV) may be used only after a determination by the Regional Supervisor that the pressure will be relieved in a safe and pollution-free manner. The setting level at which the primary and redundant safety

equipment actuates shall not exceed the pipeline's MAOP.

(e) Pipelines shall be provided with an external protective coating capable of minimizing underfilm corrosion and a cathodic protection system designed to mitigate corrosion for at least 20 years.

(f) Pipelines shall be designed and maintained to mitigate any reasonably anticipated detrimental effects of water currents, storm or ice scouring, soft bottoms, mud slides, earthquakes, subfreezing temperatures, and other environmental factors.

§ 250.153 Installation, testing, and repair requirements for DOI pipelines.

(a)(1) Pipelines greater than 8-5/8 inches in diameter and installed in water depths of less than 200 feet shall be buried to a depth of at least 3 feet unless they are located in pipeline congested areas or seismically active areas as determined by the Regional Supervisor. Nevertheless, the Regional Supervisor may require burial of any pipeline if the Regional Supervisor determines that such burial will reduce the likelihood of environmental degradation or that the pipeline may constitute a hazard to trawling operations or other uses. A trawl test or diver survey may be required to determine whether or not pipeline burial is necessary or to determine whether a pipeline has been properly buried.

(2) Pipeline valves, taps, tie-ins, capped lines, and repaired sections that could be obstructive shall be provided with at least 3 feet of cover unless the Regional Supervisor determines that such items present no hazard to trawling or other operations. A protective device may be used to cover an obstruction in lieu of burial if it is approved by the Regional Supervisor prior to installation.

(3) Pipelines shall be installed with a minimum separation of 18 inches at pipeline crossings and from obstructions.

(4) Pipeline risers installed after April 1, 1988, shall be protected from physical damage that could result from contact with floating vessels. Riser protection on pipelines installed on or before April 1, 1988, may be required when the Regional Supervisor determines that significant damage potential exists.

(b)(1) Pipelines shall be hydrostatically tested with water at a stabilized pressure of at least 1.25 times the MAOP for at least 8 hours when installed, relocated, uprated, or reactivated after being out-of-service for more than 1 year.

(2) Prior to returning a pipeline to service after a repair, the pipeline shall be pressure tested with water or processed natural gas at a minimum stabilized pressure of at least 1.25 times the MAOP for at least 2 hours.

(3) Pipelines shall not be pressure tested at a pressure which produces a stress in the pipeline in excess of 95 percent of the specified minimum-yield strength of the pipeline. A temperature recorder measuring test fluid temperature synchronized with a pressure recorder along with deadweight test readings shall be employed for all pressure testing. When a pipeline is pressure tested, no observable leakage shall be allowed. Pressure gauges and recorders shall be of sufficient accuracy to verify that leakage is not occurring.

(4) The Regional Supervisor may require pressure testing of pipelines to verify the integrity of the system when the Regional Supervisor determines that there is a reasonable likelihood that the line has been damaged or weakened by external or internal conditions.

(c) When a pipeline is repaired utilizing a clamp, the clamp shall be a full encirclement clamp able to withstand the anticipated pipeline pressure.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988; 57 FR 26997, June 17, 1992]

§ 250.154 Safety equipment requirements for DOI pipelines.

(a) The lessee shall ensure the proper installation, operation, and maintenance of safety devices required by this section on all incoming, departing, and crossing pipelines on platforms.

(b)(1)(i) Incoming pipelines to a platform shall be equipped with a flow safety valve (FSV).

(ii) For sulphur operations, incoming pipelines delivering gas to the power plant platform may be equipped with high- and low-pressure sensors (PSHL),

which activate audible and visual alarms in lieu of requirements in paragraph (b)(1)(i) of this section. The PSHL shall be set at 15 percent or 5 psi, whichever is greater, above and below the normal operating pressure range.

(2) Incoming pipelines boarding to a production platform shall be equipped with an automatic shutdown valve (SDV) immediately upon boarding the platform. The SDV shall be connected to the automatic- and remote-emergency shut-in systems.

(3) Departing pipelines receiving production from production facilities shall be protected by high- and low-pressure sensors (PSHL) to directly or indirectly shut in all production facilities. The PSHL shall be set not to exceed 15 percent above and below the normal operating pressure range. However, high pilots shall not be set above the pipeline's MAOP.

(4) Crossing pipelines on production or manned nonproduction platforms which do not receive production from the platform shall be equipped with an SDV immediately upon boarding the platform. The SDV shall be operated by a PSHL on the departing pipelines and connected to the platform automatic- and remote-emergency shut-in systems.

(5) The Regional Supervisor may require that oil pipelines be equipped with a metering system to provide a continuous volumetric comparison between the input to the line at the structure(s) and the deliveries onshore. The system shall include an alarm system and shall be of adequate sensitivity to detect variations between input and discharge volumes. In lieu of the foregoing, a system capable of detecting leaks in the pipeline may be substituted with the approval of the Regional Supervisor.

(6) Pipelines incoming to a subsea tie-in shall be equipped with a block valve and an FSV. Bidirectional pipelines connected to a subsea tie-in shall be equipped with only a block valve.

(7) Gas-lift or water-injection pipelines on unmanned platforms need only be equipped with an FSV installed immediately upstream of each casing annulus or the first inlet valve on the christmas tree.

(8) Bidirectional pipelines shall be equipped with a PSHL and an SDV immediately upon boarding each platform.

(9) Pipeline pumps shall comply with Section A7 of API RP 14C. The setting levels for the PSHL devices are specified in paragraph (b)(3) of this section.

(c) If the required safety equipment is rendered ineffective or removed from service on pipelines which are continued in operation, an equivalent degree of safety shall be provided. The safety equipment shall be identified by the placement of a sign on the equipment stating that the equipment is rendered ineffective or removed from service.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 56 FR 32100, July 15, 1991]

§ 250.155 Inspection requirements for DOI pipelines.

(a) Pipeline routes shall be inspected at time intervals and methods prescribed by the Regional Supervisor for indication of pipeline leakage. The results of these inspections shall be retained for at least 2 years and be made available to the Regional Supervisor upon request.

(b) When pipelines are protected by rectifiers or anodes for which the initial life expectancy of the cathodic protection system either cannot be calculated or calculations indicate a life expectancy of less than 20 years, such pipelines shall be inspected annually by taking measurements of pipe-to-electrolyte potential measurements.

§ 250.156 Abandonment and out-of-service requirements for DOI pipelines.

(a)(1) A pipeline may be abandoned in place if, in the opinion of the Regional Supervisor, it does not constitute a hazard to navigation, commercial fishing operations, or unduly interfere with other uses in the OCS. Pipelines to be abandoned in place shall be flushed, filled with seawater, cut, and plugged with the ends buried at least 3 feet.

(2) Pipelines abandoned by removal shall be pigged, unless the Regional Supervisor determines that such procedure is not practical, and flushed with water prior to removal.

(b)(1) Pipelines taken out-of-service shall be blind flanged or isolated with a closed block valve at each end.

(2) Pipelines taken out-of-service for a period of more than 1 year shall be flushed and filled with inhibited seawater.

(3) Pipelines taken out-of-service shall be returned to service within 5 years or be abandoned in accordance with the requirements of paragraph (a)(1) or (2) of this section.

§ 250.157 Applications.

(a) Applications for the approval of the installation of a lease term pipeline or for the granting of a right-of-way shall be submitted in quadruplicate to the Regional Supervisor and shall include the following:

(1) Plat(s) drawn to a scale specified by the Regional Supervisor showing major features and other pertinent data including area, lease, and block designations; water depths; route; length in Federal waters; width of right-of-way, if applicable; connecting facilities; size; product(s) to be transported with anticipated gravity or density; burial depth; direction of flow; X-Y coordinates of key points; and the location of other pipelines that will be connected to or crossed by the proposed pipeline(s). The initial and terminal points of the pipeline and any continuation into State jurisdiction shall be accurately located even if the pipeline is to have an onshore terminal point. A plat(s) submitted for a pipeline right-of-way shall bear a signed certificate upon its face by the engineer who made the map that certifies that the right-of-way is accurately represented upon the map and that the design characteristics of the associated pipeline are in accordance with applicable regulations.

(2) A schematic drawing showing the size, weight, grade, wall thickness, and type of line pipe and risers; pressure-regulating devices (including back-pressure regulators); sensing devices with associated pressure-control lines; PSV's and settings; SDV's, FSV's, and block valves; and manifolds. This schematic drawing shall also show input source(s), e.g., wells, pumps, compressors, and vessels; maximum input pressure(s); the rated working pressure, as specified by ANSI or API, of all valves, flanges, and fittings; the initial receiving equipment and its rated working pressure; and associated safety equipment and pig launchers and receivers.

(3) General information as follows:

(i) Description of cathodic protection system. If pipeline anodes are to be used, specify the type, size, weight, number, spacing, and anticipated life;

(ii) Description of external pipeline coating system;

(iii) Description of internal protective measures;

(iv) Specific gravity of the empty pipe;

(v) MSP;

(vi) MAOP and calculations used in its determination;

(vii) Hydrostatic test pressure, medium, and period of time that the line will be tested;

(viii) MAOP of the receiving pipeline or facility,

(ix) Proposed date for commencing installation and estimated time for construction; and

(x) Type of protection to be afforded crossing pipelines, subsea valves, taps, and manifold assemblies, if applicable.

(4) The application shall include a description of any additional design precautions which were taken to enable the pipeline to withstand the effects of water currents, storm or ice scouring, soft bottoms, mudslides, earthquakes, permafrost, and other environmental factors.

(5) The application shall include a shallow hazards survey report and, if required by the Regional Director, an archaeological resource report that covers the entire length of the pipeline. A shallow hazards analysis may be included in a lease term pipeline application in lieu of the shallow hazards survey report with the approval of the Regional Director. The Regional Director may require the submission of the data upon which the report or analysis is based.

(b) Applications to modify an approved lease term pipeline or right-of-way grant shall be submitted in quadruplicate to the Regional Supervisor. These applications need only address those items in the original application affected by the proposed modification.

(c) Applications to abandon a lease term pipeline or relinquish a right-of-way grant shall be submitted in triplicate to the Regional Supervisor and shall include the following:

(1) Reason for operation,

(2) Proposed procedures,

(3) ''As-built'' location plat,

(4) Length in feet of segment to be abandoned or relinquished, and

(5) Length in feet of segment remaining.

[53 FR 10690, Apr. 1, 1988, as amended at 59 FR 53094, Oct. 21, 1994]

§ 250.158 Reports.

(a) The lessee, or right-of-way holder, shall notify the Regional Supervisor at least 48 hours prior to commencing the installation or relocation of a pipeline or conducting a pressure test on a pipeline.

(b) The lessee or right-of-way holder shall submit a report to the Regional Supervisor within 90 days after completion of any pipeline construction. The report, submitted in triplicate, shall include an ''as-built'' location plat drawn to a scale specified by the Regional Supervisor showing the location, length in Federal waters, and X–Y coordinates of key points; the completion date; the proposed date of first operation; and the HPT data. Pipeline right-of-way ''as-built'' location plats shall be certified by a registered engineer or land surveyor and show the boundaries of the right-of-way as granted. If there is a substantial deviation of the pipeline route as granted in the right-of-way, the report shall include a discussion of the reasons for such deviation.

(c) The lessee or right-of-way holder shall report to the Regional Supervisor any pipeline taken out of service. If the period of time in which the pipeline is out of service is greater than 60 days, written confirmation is also required.

(d) The lessee or right-of-way holder shall report to the Regional Supervisor when any required pipeline safety equipment is taken out of service for more than 12 hours. The Regional Supervisor shall be notified when the equipment is returned to service.

(e) The lessee or right-of-way holder shall notify the Regional Supervisor prior to the repair of any pipeline or as soon as practicable. A detailed report of the repair of a pipeline or pipeline component shall be submitted to the Regional Supervisor within 30 days after completion of the repairs. The report shall include the following:

(1) Description of repairs,

(2) Results of pressure test, and

(3) Date returned to service.

(f) The Regional Supervisor may require that DOI pipeline failures be analyzed and that samples of a failed section be examined in a laboratory to assist in determining the cause of the failure. A comprehensive written report of the information obtained shall be submitted by the lessee to the Regional Supervisor as soon as available.

(g) If the effects of scouring, soft bottoms, or other environmental factors are observed to be detrimentally affecting a pipeline, a plan of corrective action shall be submitted to the Regional Supervisor for approval within 30 days of the observation. A report of the remedial action taken shall be submitted to the Regional Supervisor by the lessee or right-of-way holder within 30 days after completion.

(h) The results and conclusions of measurements of pipe-to-electrolyte potential measurements taken annually on DOI pipelines in accordance with § 250.155(b) of this part shall be submitted to the Regional Supervisor by the lessee before March of each year.

§ 250.159 General requirements for a pipeline right-of-way grant.

(a)(1) In addition to applicable requirements of §§ 250.150 through 250.158 and other regulations of this part, regulations of the Department of Transportation, Department of the Army, and the Federal Energy Regulatory Commission (FERC), when a pipeline qualifies as a right-of-way pipeline, the pipeline shall not be installed until a right-of-way has been requested and granted in accordance with this subpart. The right-of-way grant is issued pursuant to 43 U.S.C. 1334(e) and may be acquired and held only by citizens and nationals of the United States; aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20); private,

public, or municipal corporations organized under the laws of the United States or territory thereof, the District of Columbia, or of any State; or associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

(2) A right-of-way shall include the site on which the pipeline and associated structures are to be situated, shall not exceed 200 feet in width unless safety and environmental factors during construction and operation of the associated right-of-way pipeline require a greater width, and shall be limited to the area reasonably necessary for pumping stations or other accessory structures.

(b)(1) When you apply for, or are the holder of, a right-of-way, you must:

(i) Provide and maintain a $300,000 bond (in addition to the bond coverage required in part 256) that guarantees compliance with all the terms and conditions of the rights-of-way you hold in an OCS area; and

(ii) Provide additional security if the Regional Director determines that a bond in excess of $300,000 is needed.

(2) For the purposes of this paragraph, listed below are the four areas:

(i) The Alaska OCS Region,

(ii) The Atlantic OCS Region,

(iii) The Gulf of Mexico OCS Region, and

(iv) The Pacific OCS Region

(3) If, as the result of a default, the surety on a right-of-way grant bond makes payment to the Government of any indebtedness under a grant secured by the bond, the face amount of such bond and the surety's liability shall be reduced by the amount of such payment.

(4) After a default, a new bond in the amount of $300,000 shall be posted within 6 months or such shorter period as the Regional Supervisor may direct. Failure to post a new bond shall be grounds for forfeiture of all grants covered by the defaulted bond.

(c) An applicant, by accepting a right-of-way grant, agrees to comply with the following requirements:

(1) The right-of-way holder shall comply with applicable laws and regulations and the terms of the grant.

(2) For the first calendar year, or fraction thereof, and annually thereafter, the right-of-way holder shall pay MMS, in advance, an annual rental of $15 for each statute mile, or fraction thereof, traversed by the right-of-way and $75 for each area to be used as a site for an accessory to the right-of-way pipeline including, but not limited to, a platform. Payments may be on an annual basis, for a 5-year period, or for multiples of 5 years.

(3) The granting of the right-of-way shall be subject to the express condition that the rights granted shall not prevent or interfere in any way with the management, administration, or the granting of other rights by the United States, either prior or subsequent to the granting of the right-of-way. Moreover, the holder agrees to allow the occupancy and use by the United States, its lessees, or other right-of-way holders, of any part of the right-of-way grant not actually occupied or necessarily incident to its use for any necessary operations involved in the management, administration, or the enjoyment of such other granted rights.

(4) If the right-of-way holder discovers any archaeological resource while conducting operations within the right-of-way, the right-of-way holder shall immediately halt operations within the area of the discovery and report the discovery to the Regional Director. If investigations determine that the resource is significant, the Regional Director will inform the lessee how to protect it.

(5) The Regional Supervisor shall be kept informed at all times of the right-of-way holder's address and, if a corporation, the address of its principal place of business and the name and address of the officer or agent authorized to be served with process.

(6) The right-of-way holder shall pay the United States or its lessees or right-of-way holders, as the case may be, the full value of all damages to the property of the United States or its said lessees or right-of-way holders and shall indemnify the United States against any and all liability for damages to life, person, or property arising from the occupation and use of the area covered by the right-of-way grant.

(7)(i) The holder of a right-of-way oil or gas pipeline shall transport or purchase oil or natural gas produced from submerged lands in the vicinity of the pipeline without discrimination and in such proportionate amounts as the FERC may, after a full hearing with due notice thereof to the interested parties, determine to be reasonable, taking into account, among other things, conservation and the prevention of waste.

(ii) Unless otherwise exempted by FERC pursuant to 43 U.S.C. 1334(f)(2), the holder shall—

(A) Provide open and nondiscriminatory access to a right-of-way pipeline to both owner and nonowner shippers, and

(B) Comply with the provisions of 43 U.S.C. 1334(f)(1)(B) under which FERC may order an expansion of the throughput capacity of a right-of-way pipeline which is approved after September 18, 1978, and which is not located in the Gulf of Mexico or the Santa Barbara Channel.

(8) The area covered by a right-of-way and all improvements thereon shall be kept open at all reasonable times for inspection by the Minerals Management Service (MMS). The right-of-way holder shall make available all records relative to the design, construction, operation, maintenance and repair, and investigations on or with regard to such area.

(9) Upon relinquishment, forfeiture, or cancellation of a right-of-way grant, the right-of-way holder shall remove all platforms, structures, domes over valves, pipes, taps, and valves along the right-of-way. All of these improvements shall be removed by the holder within 1 year of the effective date of the relinquishment, forfeiture, or cancellation unless this requirement is waived in writing by the Regional Supervisor. All such improvements not removed within the time provided herein shall become the property of the United States but that shall not relieve the holder of liability for the cost of their removal or for restoration of the site. Furthermore, the holder is responsible for accidents or damages which might occur as a result of failure to timely remove improvements and equipment and restore a site. An application for relinquishment of a right-of-way grant shall be filed in accordance with § 250.164 of this part.

(d) Failure to comply with the Act, regulations, or any conditions of the right-of-way grant prescribed by the Regional Supervisor shall be grounds for forfeiture of the grant in an appropriate judicial proceeding instituted by the United States in any U.S. District Court having jurisdiction in accordance with the provisions of 43 U.S.C. 1349.

(e) Any right-of-way granted under the provisions of this subpart remains in effect as long as the associated pipeline is properly maintained and used for the purpose for which the grant was made, unless otherwise expressly stated in the grant. Temporary cessation or suspension of pipeline operations shall not cause the grant to expire. However, if the purpose of the grant ceases to exist or use of the associated pipeline is permanently discontinued for any reason, the grant shall be deemed to have expired.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 55 FR 47753, Nov. 15, 1990; 59 FR 53094, Oct. 21, 1994; 62 FR 27955, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27955, May 22, 1997, § 250.159 was amended by revising paragraph (b)(1), effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 250.159 General requirements for a pipeline right-of-way grant.

* * * * *

(b)(1) The applicant shall furnish the Regional Supervisor a corporate surety bond in the sum of $300,000 conditioned on compliance with all the terms of the grant. Such bond shall not be required if the applicant already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of all right-of-way grants held by the applicant in the OCS for the area in which the grant to be issued is situated. This bond shall be in addition to any bond required of a lessee in 30 CFR Part 256.

* * * * *

§ 250.160 Applications for a pipeline right-of-way grant.

(a) An application for a new or modified pipeline right-of-way grant shall

be submitted in quadruplicate to the Regional Supervisor. It shall address those items required by § 250.157 (a) or (b) of this part, as applicable. It shall also state the primary purpose for which the right-of-way is to be used. If the right-of-way has been utilized prior to the time the application is made, the application shall state the date such utilization commenced, by whom, and the date the applicant obtained control of the improvement. A nonrefundable filing fee of $1,400 and the rental required under § 250.159(c)(2) of this part shall accompany a new right-of-way application. An application to modify an approved right-of-way grant shall be accompanied by the additional rental required under § 250.159(c)(2), if applicable. A separate application shall be filed for each right-of-way.

(b)(1) An individual applicant shall submit a statement of citizenship or nationality with the application. An applicant who is an alien lawfully admitted for permanent residence in the United States shall also submit evidence of such status with the application.

(2) If the applicant is an association (including a partnership), the application shall also be accompanied by a certified copy of the articles of association or appropriate reference to a copy of such articles already filed with MMS and a statement as to any subsequent amendments.

(3) If the applicant is a corporation, the application shall also include the following:

(i) A statement certified by the Secretary or Assistant Secretary of the corporation with the corporate seal showing the State in which it is incorporated and the name of the person(s) authorized to act on behalf of the corporation, or

(ii) In lieu of such a statement, an appropriate reference to statements or records previously submitted to MMS (including material submitted in compliance with prior regulations).

(c) The application shall include a list of every lessee and right-of-way holder whose lease or right-of-way is intersected by the proposed right-of-way. The application shall also include a statement that a copy of the application has been sent by registered or certified mail to each such lessee or right-of-way holder.

(d) The applicant shall include in the application an original and three copies of a completed Nondiscrimination in Employment form (YN 3341-1 dated July 1982). These forms are available at each MMS regional office.

§ 250.161 Granting a pipeline right-of-way.

(a) In considering an application for a right-of-way, the Regional Supervisor shall consider the potential effect of the associated pipeline on the human, marine, and coastal environments, life (including aquatic life), property, and mineral resources in the entire area during construction and operational phases. The Regional Supervisor shall prepare an environmental analysis in accordance with applicable policies and guidelines. To aid in the evaluation and determinations, the Regional Supervisor may request and consider views and recommendations of appropriate Federal Agencies, hold public meetings after appropriate notice, and consult, as appropriate, with State agencies, organizations, industries, and individuals. Before granting a pipeline right-of-way, the Regional Supervisor shall give consideration to any recommendation by the intergovernmental planning program, or similar process, for the assessment and management of OCS oil and gas transportation.

(b) Should the proposed route of a right-of-way adjoin and subsequently cross any State submerged lands, the applicant shall submit evidence to the Regional Supervisor that the State(s) so affected has reviewed the application. The applicant shall also submit any comment received as a result of that review. In the event of a State recommendation to relocate the proposed route, the Regional Supervisor may consult with the appropriate State officials.

(c)(1) The applicant shall submit photocopies of return receipts to the Regional Supervisor that indicate the date that each lessee or right-of-way holder referenced in § 250.160(c) of this part has received a copy of the application. Letters of no objection may be

submitted in lieu of the return receipts.

(2) The Regional Supervisor shall not take final action on a right-of-way application until the Regional Supervisor is satisfied that each such lessee or right-of-way holder has been afforded at least 30 days from the date determined in paragraph (c)(1) of this section in which to submit comments.

(d) If a proposed right-of-way crosses any lands not subject to disposition by mineral leasing or restricted from oil and gas activities, it shall be rejected by the Regional Supervisor unless the Federal Agency with jurisdiction over such excluded or restricted area gives its consent to the granting of the right-of-way. In such case, the applicant, upon a request filed within 30 days after receipt of the notification of such rejection, shall be allowed an opportunity to eliminate the conflict.

(e)(1) If the application and other required information are found to be in compliance with applicable laws and regulations, the right-of-way may be granted. The Regional Supervisor may prescribe, as conditions to the right-of-way grant, stipulations necessary to protect human, marine, and coastal environments, life (including aquatic life), property, and mineral resources located on or adjacent to the right-of-way.

(2) If the Regional Supervisor determines that a change in the application should be made, the Regional Supervisor shall notify the applicant that an amended application shall be filed subject to stipulated changes. The Regional Supervisor shall determine whether the applicant shall deliver copies of the amended application to other parties for comment.

(3) A decision to reject an application shall be in writing and shall state the reasons for the rejection.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1988]

§ 250.162 Requirements for construction under a right-of-way grant.

(a) Failure to construct the associated right-of-way pipeline within 5 years of the date of the granting of a right-of-way shall cause the grant to expire.

(b)(1) A right-of-way holder shall ensure that the right-of-way pipeline is constructed in a manner that minimizes deviations from the right-of-way as granted.

(2) If, after constructing the right-of-way pipeline, it is determined that a deviation from the proposed right-of-way as granted has occurred, the right-of-way holder shall—

(i) Notify the operators of all leases and holders of all right-of-way grants in which a deviation has occurred, and within 60 days of the date of the acceptance by the Regional Supervisor of the completion of pipeline construction report, provide the Regional Supervisor with evidence of such notification; and

(ii) Relinquish any unused portion of the right-of-way.

(3) Substantial deviation of a right-of-way pipeline as constructed from the proposed right-of-way as granted may be grounds for forfeiture of the right-of-way.

(c) If the Regional Supervisor determines that a significant change in conditions has occurred subsequent to the granting of a right-of-way but prior to the commencement of construction of the associated pipeline, the Regional Supervisor may suspend or temporarily prohibit the commencement of construction until the right-of-way grant is modified to the extent necessary to address the changed conditions.

§ 250.163 Assignment of a right-of-way grant.

(a) Assignment may be made of a right-of-way grant, in whole or of any lineal segment thereof, subject to the approval of the Regional Supervisor. An application for approval of an assignment of a right-of-way or of a lineal segment thereof, shall be filed in triplicate with the Regional Supervisor.

(b) Any application for approval for an assignment, in whole or in part, of any right, title, or interest in a right-of-way grant shall be accompanied by the same showing of qualifications of the assignees as is required of an applicant for a right-of-way in § 250.160 of this subpart and shall be supported by a statement that the assignee agrees to comply with and to be bound by the terms and conditions of the right-of-

way grant. The assignee shall satisfy the bonding requirements in § 250.159(b) of this part. No transfer shall be recognized unless and until it is first approved, in writing, by the Regional Supervisor. A non refundable filing fee of $50 shall accompany the application for the approval of an assignment.

§ 250.164 Relinquishment of a right-of-way grant.

A right-of-way grant or a portion thereof may be surrendered by the holder by filing a written relinquishment in triplicate with the Regional Supervisor. It shall contain those items addressed in § 250.157(c) of this part. A relinquishment shall take effect on the date it is filed subject to the satisfaction of all outstanding debts, fees, or fines and the requirements in § 250.159(c)(9) of this part.

Subpart K—Oil and Gas Production Rates

§ 250.170 Definitions for production rates.

Terms used in this subpart shall have meanings given below:

Enhanced recovery operations means pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

Gas reservoir means a reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

Gas-well completion means a well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.

Maximum Efficient Rate (MER) means the maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

Maximum Production Rate (MPR) means the approved maximum daily rate at which oil or gas may be produced from a specified oil-well or gas-well completion.

Nonsensitive reservoir means a reservoir in which ultimate recovery is not decreased by high reservoir production rates.

Oil reservoir means a reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

Oil reservoir with an associated gas cap means a reservoir that contains hydrocarbons in both a liquid and gaseous (two-phase) state.

Oil-well completion means a well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

Sensitive reservoir means a reservoir in which ultimate recovery is decreased by high reservoir production rates. A high reservoir production rate is one which exceeds the MER.

Waste of oil and gas means: (1) The physical waste of oil and gas; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well(s) in a manner which causes or tends to cause a reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or (4) the inefficient storage of oil.

§ 250.171 General requirements and classification of reservoirs.

(a) Wells and reservoirs shall be produced at rates that will provide economic development and depletion of the hydrocarbon resources in a manner that would maximize the ultimate recovery without adversely affecting correlative rights.

(b) For directionally drilled wells in which the completed interval is closer than 500 feet from a unit or lease line or for vertically drilled wells in which the surface location is closer than 500 feet from a unit or lease line, for which the unit, lease, or royalty interests are not the same, the prior approval by the Regional Supervisor is required before production is commenced. An operator requesting such an approval shall furnish the Regional Supervisor with letters expressing acceptance or objection from operators of offset properties.

(c) The lessee shall propose a classification for each reservoir as an oil reservoir, an oil reservoir with an associated gas cap or a gas reservoir, and as sensitive or nonsensitive.

(d) All oil reservoirs with associated gas caps shall be initially classified as sensitive and shall require establishing a maximum efficient production rate and balancing of production in accordance with § 250.172(a) (1) and (5) of this part. All other oil reservoirs and all gas reservoirs shall be initially classified as nonsensitive.

(e) A reservoir may be reclassified by the Minerals Management Service (MMS) as to type and sensitivity at any time during its productive life when information becomes available showing that reclassification is warranted.

§ 250.172 Oil and gas production rates.

(a) *MER*. (1) The lessee shall submit a proposed MER for each producing sensitive reservoir on Form MMS–127, Request for Reservoir Maximum Efficient Rate (MER), along with appropriate supporting information to the Regional Supervisor within 45 days after discovering that a reservoir is sensitive.

(2) The lessee may propose to revise an MER by submitting Form MMS–127 with appropriate supporting information.

(3) The effective date of an MER for a reservoir or revision thereof shall be the first day of the month in which Form MMS–127 is submitted.

(4) When approved, the MER shall not be exceeded, except as provided in paragraph (a)(5) of this section.

(5) If a reservoir is produced at a rate in excess of the MER for any month, the lessee should initiate measures necessary to balance production (offset overproduction by underproduction) during the next succeeding month. All overproduction shall be balanced by the end of the next succeeding calendar quarter following the quarter in which the overproduction occurred. Any operation in an overproduction status in any reservoir for two successive calendar quarters shall be shut in from that reservoir until the actual production is equal to that which would have occurred under the approved MER, unless an alternative plan is approved by the Regional Supervisor.

(6) The lessee shall review the MER for each producing sensitive reservoir at least once a year and submit Form MMS–127 with appropriate supporting information.

(7) The lessee may request the reclassification of a reservoir from sensitive to nonsensitive and request approval for termination of an MER by submitting Form MMS–127 with information supporting the reclassification and termination.

(8) At the request of the Regional Supervisor, the lessee shall furnish the information specified on Form MMS–127 for any producing nonsensitive reservoir.

(9) Public information copies of Form MMS–127 shall be submitted in accordance with § 250.17.

(b) *MPR*. (1) The lessee shall propose an MPR for each producing well completion together with full information on the method used in its determination. The MPR shall be based on well tests and any limitations imposed by well and surface equipment, sand production, gas-oil and water-oil ratios, location of perforated intervals, and prudent operating practices. The sum of the MPR's of wells completed in a sensitive reservoir shall not exceed the approved MER.

(2) The lessee shall conduct a well-flow potential test within 30 days of the date of first continuous production on all new, recompleted, and reworked well completions. Within 15 days after the end of the test period, the lessee shall submit a proposed MPR with well potential test for the individual well completion on Form MMS–126, Well Potential Test Report and Request for Maximum Production Rate (MPR). The initial MPR shall not exceed 110 percent of the test rate submitted and shall be effective on the first day of the month following the end of the test period if approved by the Regional Supervisor. During the 30-day period allowed for testing, the lessee may produce a new, recompleted, or reworked completion at rates necessary to establish the MPR. After the 30-day period and prior to approval of the initial MPR, a well completion may be produced at a rate not to exceed the proposed rate. The

lessee shall report the total production obtained during the test period and shall identify all other wells completed in the reservoir on Form MMS–126.

(3) At least one well test shall be conducted during a calendar half for producing oil-well and gas-well completions and results submitted on Form MMS–128, Semiannual Well Test Report. Well tests shall be submitted within 45 days of the day the test was conducted.

(4) Unless otherwise ordered by the Regional Supervisor, a revised MPR shall automatically be approved for each well completion for each well test submitted equal to 110 percent of the test rate. The revised MPR will be effective on the first day of the month following the date the well test was conducted. Prior to the approval of a proposed increase of the MPR, a well completion may be produced at a rate not to exceed the proposed increased rate.

(5) When a well test is not submitted during a calendar half for a producing oil-well or gas-well completion, the MPR will be automatically canceled effective on the first day of the appropriate following calendar half.

(6) When the results of a semiannual well test for an oil-well or gas-well completion cannot be submitted within the specified time, the lessee shall request an extension of time for submitting those test results. The extension must be approved in advance by the Regional Supervisor to continue production under the last approved MPR.

(7) When approved by the Regional Supervisor, an MPR shall not be exceeded, except as provided in paragraphs (b)(4) and (c) of this section.

(8) Public Information copies of Form MMS–126 shall be submitted in accordance with § 250.17.

(9) Public information copies of Form MMS–128 shall be submitted in accordance with § 250.17.

(c) *Temporary rates.* Temporary production rates resulting from normal variations and fluctuations exceeding a well MPR or reservoir MER shall not be considered a violation, provided that such production in excess of an approved MER is balanced by production in accordance with the provisions of paragraph (a)(5) of this section.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.173 Well production testing.

(a) The required well testing shall be conducted for a period of not less than four consecutive hours. Immediately prior to the 4-hour test period, the well completion shall have produced under stabilized conditions for a period of not less than six consecutive hours. The 6-hour pretest period shall not begin until after the recovery of a volume of fluid equivalent to the amount of fluids introduced into the formation during completion, recompletion, reworking, or treatment operations. Measured gas volumes shall be adjusted to the standard conditions of 14.73 pounds per square inch absolute (psia) (15.025 psia in the Gulf of Mexico OCS Region) and 60 °F for all tests. When orifice meters are used, a specific gravity for the gas shall be obtained or estimated, and a specific gravity-correction factor shall be applied to the orifice coefficient. The Regional Supervisor may require a prolonged test or retest of a well completion if the test is determined to be necessary for the establishment of a well MPR or a reservoir MER. The Regional Supervisor may approve test periods of less than 4 hours and pretest stabilization periods of less than 6 hours for well completions provided that test reliability can be demonstrated under such procedures.

(b) At the request of the Regional Supervisor, the lessee shall conduct a multipoint back-pressure test to determine the theoretical open-flow potential of a gas well. The test shall be conducted within 30 days of the Regional Supervisor's request or within the time period specified by the Regional Supervisor.

(c) An MMS representative may witness any well test of oil-well and gas-well completions. Upon request, a lessee shall provide advance notice to the Regional Supervisor of the time and date of well tests.

§ 250.174 Bottomhole pressure survey.

(a) For each new reservoir, the lessee shall conduct a static bottomhole pressure survey within 3 months after the date of first continuous production.

(b) For each producing reservoir with three or more producing completions, the lessee shall conduct annual static bottomhole pressure surveys in a sufficient number of key wells to establish an average reservoir pressure. The Regional Supervisor may require that a survey be performed on specific wells.

(c) The results of all static bottomhole pressure surveys obtained by the lessee shall be filed with the Regional Supervisor within 60 days after the date of the survey.

§ 250.175 Flaring or venting gas and burning liquid hydrocarbons.

(a) Lessees may flare or vent oil-well gas or gas-well gas without receiving prior approval from the Regional Supervisor only in the following situations:

(1) When gas vapors are flared or vented in small volumes from storage vessels or other low-pressure production vessels and cannot be economically recovered.

(2) During an equipment failure or to relieve system pressures. The lessee must comply with the following conditions:

(i) Lessees must not flare or vent oil-well gas for more than 48 continuous hours unless the Regional Supervisor approves. The Regional Supervisor may specify a limit of less than 48 hours to prevent air quality degradation.

(ii) Lessees must not flare or vent gas from a facility for more than 144 cumulative hours during any calendar month unless the Regional Supervisor approves.

(iii) Lessees must not flare or vent gas-well gas beyond the time required to eliminate an emergency unless the Regional Supervisor approves.

(3) During the unloading or cleaning of a well, drill-stem testing, production testing, or other well-evaluation testing. Flaring or venting must not exceed 48 cumulative hours per testing operation on a single completion. The Regional Supervisor may allow less time to prevent air quality degradation or more time if lessees need additional time to evaluate reservoir parameters.

(b) Lessees may flare or vent oil-well gas for up to 1 year when the Regional Supervisor approves the request for one of the following reasons:

(1) The lessee initiated an action which, when completed, will eliminate flaring and venting; or

(2) The lessee submitted an evaluation supported by engineering, geologic, and economic data indicating that either:

(i) The oil and gas produced from the well(s) will not economically support the facilities necessary to save and/or sell the gas; or

(ii) There is not enough gas to market.

(c) Lessees may burn produced liquid hydrocarbons only if the Regional Supervisor approves. To burn produced liquid hydrocarbons, the lessee must demonstrate that the amounts to burn would be minimal, or that the alternatives are infeasible or pose a significant risk that may harm offshore personnel or the environment. Alternatives to burning liquid hydrocarbons include transporting the liquids or storing and re-injecting them into a producible zone.

(d) Lessees must prepare records detailing gas flaring or venting and liquid hydrocarbon burning for each facility. The records must include, at a minimum:

(1) Daily volumes of gas flared or vented and liquid hydrocarbons burned;

(2) Number of hours of flaring, venting, or burning on a daily basis;

(3) Reasons for flaring, venting, or burning; and

(4) A list of the wells contributing to flaring, venting, or burning, along with the gas-oil ratio data.

(e) Lessees must keep these records for at least 2 years. Lessees must allow Minerals Management Service representatives to inspect the records at the lessees' field office that is nearest the Outer Continental Shelf facility, or at another location agreed to by the Regional Supervisor. If the Regional Supervisor requests to see the records, lessees must provide a copy.

(f) *Requirements for flaring and venting of gas containing* H_2S—(1) *Flaring of gas*

containing H_2S. (i) The Regional Supervisor may, for safety or air pollution prevention purposes, further restrict the flaring of gas containing H_2S. The Regional Supervisor will use information provided in the lessee's H_2S Contingency Plan (§ 250.67(f)), Exploration Plan or Development and Production Plan, and associated documents in determining the need for such restrictions.

(ii) If the Regional Supervisor determines that flaring at a facility or group of facilities may significantly affect the air quality of an onshore area, the Regional Supervisor may require the operator(s) to conduct an air quality modeling analysis to determine the potential effect of facility emissions on onshore ambient concentrations of SO_2. The Regional Supervisor may require monitoring and reporting or may restrict or prohibit flaring pursuant to §§ 250.45 and 250.46.

(2) *Venting of gas containing H_2S.* You must not vent gas containing H_2S except for minor releases during maintenance and repair activities that do not result in a 15-minute time weighted average atmospheric concentration of H_2S of 20 ppm or higher anywhere on the platform.

(3) *Reporting flared gas containing H_2S.* In addition to the recordkeeping requirements of paragraphs (d) and (e) of this section, when required by the Regional Supervisor, the operator must submit to the Regional Supervisor a monthly report of flared and vented gas containing H_2S. The report must contain the following information:

(i) On a daily basis, the volume and duration of each flaring episode;

(ii) H_2S concentration in the flared gas; and

(iii) Calculated amount of SO_2 emitted.

[61 FR 25148, May 20, 1996, as amended at 62 FR 3800, Jan. 27, 1997]

§ 250.176 Downhole commingling.

(a) An application to commingle hydrocarbons produced from multiple reservoirs within a common wellbore shall be submitted to the Regional Supervisor for approval and shall include all pertinent well information, geologic and reservoir engineering data, and a schematic diagram of well equipment. The application shall provide the estimated recoverable reserves as well as any available alternate drainage points which might be used to produce the reservoirs separately.

(b) For a competitive reservoir, notice of intent to submit the application shall be sent by the applicant to all other lessees having an interest in the reservoir prior to submitting the application to the Regional Supervisor.

(c) The application shall specify the well-completion number to be used for subsequent reporting purposes.

§ 250.177 Enhanced oil and gas recovery operations.

(a) The lessee shall timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles.

(b) A proposed plan for pressure maintenance, secondary and tertiary recovery, cycling, and similar recovery operations to increase the ultimate recovery of oil and/or gas from a reservoir shall be submitted to the Regional Supervisor for approval before such operations are initiated.

(c) Periodic reports of the volumes of oil, gas, or other substances injected, produced, or reproduced shall be submitted as required by the Regional Supervisor.

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

§ 250.180 Measurement of liquid hydrocarbons.

(a) *General.* Measurement equipment shall be designed, installed, used, maintained, and tested so as to accurately and completely measure the liquid hydrocarbons produced on a lease for purposes of royalty determination. For purposes of this subpart, a liquid hydrocarbon is a mixture of hydrocarbons produced in liquid form after passing through surface separating facilities which is marketed or used as such.

(b) *Application and approval.* The lessee shall not commence production of

liquid hydrocarbons unless the Regional Supervisor has approved an application for the measurement of liquid hydrocarbons and for commingling, if applicable. The application shall contain information sufficient to demonstrate that the requirements of this section will be met. Sales meter facilities shall be appropriately located with respect to the lease(s) and transportation system(s) involved.

(c) *Sales meter facility requirements.* (1) A meter upon which royalty is based shall be considered a sales meter.

(2) Sales meter facilities shall include the following components which shall be compatible with the systems to which they are connected:

(i) A positive-displacement or other meter approved by the Regional Supervisor. The meter shall be equipped with a nonreset totalizer.

(ii) A calibrated prover tank, a master meter, a mechanical displacement prover, or other device permanent or portable capable of proving the meter approved by the Regional Supervisor.

(iii) A proportional-to-flow sampling device which is pulsed by the meter output.

(iv) A temperature measurement or temperature compensation device.

(3) Sales meter facilities shall be designed to accomplish the following:

(i) Prevent reversal of flow through the meter;

(ii) Adequately protect meters subjected to pressure pulsation or surges by the use of surge tanks, expansion chambers, or similar devices;

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

(iv) Prevent bypassing of the meter.

(4) Sales meter facilities shall be maintained to ensure the following:

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

(ii) Meters are operated 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.

(5) The required sampling device shall conform to the following:

(i) The sampling device shall be installed such that the sampling point is in the flowstream immediately upstream or downstream of the meter or divert valve,

(ii) The sample container for the sampling device shall be vapor-tight and include a mixing device to permit complete mixing of the sample prior to removal from the container, and

(iii) The sampling device is installed such that the sample probe is in the center of the flow piping in a vertical run and is located at least three pipe diameters downstream of any pipe fitting within a region of turbulent flow.

(6) When obtaining net standard volume and associated measurement parameters, the lessee shall use procedures and correction factors in accordance with the following chapters of the API Manual of Petroleum Measurement Standards (MPMS):

(i) Chapters 4.1 through 4.7, Proving Systems;

(ii) Chapters 5.1 through 5.5, Metering;

(iii)(A) Chapter 6.1, LACT System;

(B) Chapter 6.6, Pipeline Metering Systems;

(C) Chapter 6.7, Metering Viscous Hydrocarbons;

(iv)(A) Chapter 7.2, Dynamic Temperature Determination;

(B) Chapter 7.3, Static Temperature Determination Using Portable Electronic Thermometers.

(v) Chapters 8.1 and 8.2, Sampling;

(vi)(A) Chapter 9.1, Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products;

(B) Chapter 9.2, Pressure Hydrometer Test Method for Density or Relative Density;

(vii)(A) Chapter 10.1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method;

(B) Chapter10.2, Determination of Water in Crude Oil by Distillation;

(C) Chapter 10.3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure);

(D) Chapter 10.4, (Publication 2542) Methods of Test for Water and Sediment in Crude Oils;

(viii) (A) Chapter 11.1, 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 Volume to 60°F Against API Gravity at 60°F;

(B) Chapter 11.2.1, Compressibility Factors for Hydrocarbons: 0–90° API Gravity Range;

(C) Chapter 11.2.2, Compressibility Factors for Hydrocarbons: 0.350–0.637 Relative Density Range (60°F/60°F) and −50°F to 140°F Meeting Temperature;

(ix) Chapter 12.2, Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters.

(7) All run tickets pulled and/or completed during a particular month shall be sent to the Regional Supervisor, within 15 days following the end of the month and shall clearly identify all observed data, all correction factors not included in the meter factor, the net standard volume, and all calculations and factors utilized.

(d) *Sales meter provings*. Sales meters for liquid hydrocarbons shall be proved and calibrated in accordance with the following requirements:

(1) The Minerals Management Service (MMS) representatives shall be permitted to witness regularly scheduled provings or any proving requested by the Regional Supervisor.

(2) The integrity of the calibration of each mechanical displacement prover, prover tank, master meter, or other type of prover shall be traceable to test measures which have been certified by the National Bureau of Standards.

(3) Master meters, mechanical-displacement provers, and prover tanks shall be calibrated in accordance with the following requirements:

(i) The master meter shall be calibrated to obtain a master meter factor before using the master meter to establish an operating meter factor. The master meter shall be calibrated with a fluid of similar gravity, viscosity, and temperature as flows through the operating meter and with a similar flow rate. This calibration shall be conducted monthly but the time between calibration shall not exceed 6 weeks unless a longer period of time is approved by the Regional Supervisor.

(ii) The lessee shall calibrate a master meter by conducting and recording runs until the results of two consecutive runs, if a prover tank is used, or five out of six consecutive runs, if a mechanical-displacement prover is used, produce results such that the greatest difference in the meter factors between the runs is not greater than 0.0002. The average of the two or the five runs which produced the acceptable results shall be used to compute the master meter factor.

(iii) The master meter may be installed either upstream or downstream of the operating meter but shall be upstream of any back-pressure or reverse flow check valves associated with the operating meter.

(iv) Mechanical-displacement provers and prover tanks shall be calibrated at least every 5 years in accordance with the API MPMS, Chapters 4.1 through 4.7 and 11.2.3. A copy of each calibration report shall be submitted to the Regional Supervisor within 15 days following calibration.

(v) When calibrating meters with a mechanical-displacement prover, prover tank, or master meter, the following appropriate correction factors shall be taken into account:

(A) The change in prover volume due to pressure in the steel pipe (Cps) using API MPMS, Chapter 12, Section 2, Appendix A, Table A–3, Pressure Correction Factors for Steel, Cps;

(B) The change in volume of the test liquid with the change in temperature (Ctl) using APIMPMS, Chapter 11.1, Volume I, Table 6A, Generalized Crude Oils and JP–4, Correction of Volume to 60°F Against API Gravity at 60°F;

(C) The change in prover volume due to the change in temperature (Cts) using API MPMS, Chapter 12, Section 2, Appendix A, Table A–1, Temperature Correction Factors of Mild Steel, and Table A–2, Temperature Correction Factors for Stainless Steel; and

(D) The change in volume of the test liquid with the change in pressure (Cpl) using chapter 11.2.1 or 11.2.2, API MPMS, as appropriate.

(4) Each operating sales meter shall be proved to determine the meter factor each month, however, the time between meter factor determinations is not to exceed 42 days. Meter provings shall be in accordance with the following:

(i) When establishing an operating meter factor with a prover tank, proof runs shall be made and recorded until two consecutive runs produce results such that the difference between results is not greater than .05 percent of the prover tank volume. The average of the results of these two runs shall be used to compute the meter factor.

(ii) When establishing an operating meter factor with a master meter, proof runs shall be made until three consecutive runs produce results such that the difference in the meter factor between all runs is not greater than 0.0005. The volume of each of these runs shall be at least 10 percent of the hourly rated capacity of the operating meter and shall be of sufficient amount for the determination of an accurate operating meter factor. The average of the results of these three runs shall be used to compute the meter factor.

(iii) When establishing an operating meter factor with a mechanical-displacement prover, proof runs shall be made and recorded until five out of six consecutive runs produce results such that the difference between results is not greater than 0.0005. The average of the results of the five runs shall be used to compute the meter factor.

(5) The lessee shall submit copies of all meter proving reports for sales meters and master meters to the Regional Supervisor monthly within 15 days following the end of the month. Meter factors which are determined to be in tolerance shall be applied from the date of proving.

(i) A meter factor is considered a malfunction factor when the deviation between the factor and the previous factor exceeds 0.0025. In the event of such a malfunction, the meter shall be immediately removed from service, checked for damage or wear, adjusted and/or repaired, and reproven prior to return to service. The arithmetic average of the malfunction factor and the previous factor shall be applied to the production measured through the meter between the date of the previous factor and the date of the malfunction factor. Malfunction meter factors shall be clearly indicated on the proving report which shall also contain all appropriate remarks regarding subsequent repairs and/or adjustments.

(ii) When a malfunction results in the failure of the meter to register production, the meter shall be immediately removed from service, repaired, and reproven prior to returning it to service. The previous meter factor shall be applied to the production run between the date of that factor and the date of the failure. Any unregistered production shall be estimated by the best possible means and shall be reported as estimated production.

(iii) When the results of a sales meter proving exceed the repeatability (run tolerance) criteria and all measures excluding the adjustment and/or repair of the meter and meter components cannot bring results to within tolerance (failure to obtain repeatability of runs), a factor shall be established using proving results made prior to any adjustment and/or repair of the meter and meter components. The established factor shall be considered a malfunction factor and treated in accordance with paragraph (d)(5)(i) of this section.

(6) To correct gross volumes metered under nonstandard conditions (standard conditions are 0 pounds per square inch gauge (psig) and 60°F), Cpl factors shall be calculated into the meter factor or listed on the appropriate run ticket. The Ctl factors shall be listed on the appropriate run ticket when the meter is not automatically temperature compensated.

(7) Run tickets shall be pulled at the time of any proving which is conducted for the purpose of establishing a monthly meter factor or which results in the establishment of a malfunction meter factor. A copy of the subject run ticket shall be submitted in accordance with § 250.180(c)(7) of this part.

(e) *Allocation meter facility requirements.* (1) For purposes of this subpart, an allocation meter is a meter whose volume measurement is used to substantiate which portion of the volume measured by a royalty meter is attributable to a particular lease, measurement point, or well. Allocation meter

facilities shall include a meter, provisions for use of a device capable of proving the allocation meter, and equipment for continuous or daily sampling. Samples shall be taken continuously or daily.

(2)(i) Allocation meters measuring 50 barrels of oil per day or more shall be proven monthly, and

(ii) Allocation meters measuring less than 50 barrels of oil per day shall be proven quarterly.

(3) A copy of allocation meter proving reports must be kept at the field location for a period of 2 years.

(4) If an allocation meter proving results in a meter factor which differs from the previous meter factor by an amount greater than 0.02 and less than 0.07, the allocation meter shall be adjusted and reproven prior to return to service.

(5) If an allocation meter proving results in a meter factor which differs from the previous meter factor by an amount equal to or greater than 0.07, the allocation meter shall be repaired and reproven prior to return to service.

(f) *Sales tank requirements.* (1) Sales tank facilities designated by the Regional Supervisor as a sales location on which royalty shall be based, shall be equipped with a vapor-tight thief hatch and vent-line valve and a fill line designed to minimize free fall and splashing.

(2) A complete set of calibration charts (tank tables) shall be submitted to the Regional Supervisor prior to use of the tank for sales measurement purposes. The volume and other measurement parameters of the liquid production in sales tanks shall be obtained using correction factors and procedures in accordance with the following chapters of API MPMS:

(i)(A) Chapter 2.2A, Measurement and Calibration of Upright Cylindrical Tanks by the Manual Strapping Method;

(B) Chapter 2.2B, Measurement and Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method;

(C) Standards 2551, 2552, 2555, and 2556;

(ii)(A) Chapter 3.1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products;

(B) Chapter 3.1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging;

(C) Standard 2545, Method of Gauging Petroleum Products;

(iii)(A) Chapter 7.2, Dynamic Temperature Determination;

(B) Chapter 7.3, Static Temperature Determination Using Portable Electronic Thermometers;

(iv) Chapter 8.1 and 8.2, Sampling;

(v)(A) Chapter 9.1, Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products;

(B) Chapter 9.2, Pressure Hydrometer Test Method for Density or Relative Density;

(vi)(A) Chapter 10.1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method;

(B) Chapter 10.2, Determination of Water in Crude Oil by Distillation;

1(C) Chapter 10.3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure);

(D) Chapter 10.4, (Publication 2542) Methods of Test for Water and Sediment in Crude Oils;

(vii) Chapter 11.1, 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 Volume to 60°F, Against API Gravity at 60°F.

(3) A copy of each completed run ticket written from tank gaugings shall be submitted to the Regional Supervisor within 15 days of the run ticket being written.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 61 FR 60026, Nov. 26, 1996]

§ 250.181 Measurement of gas.

(a) *General.* The lessee shall maintain all gas sales or allocation meters designated by the Regional Supervisor in accordance with the requirements of this section.

(b) *Applications and approvals.* The lessee shall not commence production

of gas hydrocarbons unless the Regional Supervisor has approved an application for measurement of gas production. The application shall be submitted to the Regional Supervisor for approval and shall contain information sufficient to demonstrate that the requirements of this section will be met.

(c) *Gas meter requirements.* (1) The measuring equipment shall be installed and operated in accordance with the recommendations contained in the API MPMS, Chapters 14.3, Parts 1,2, and 3; 14.5; 14.6; and 14.8, Natural Gas Fluids Measurement.

(2) The unit of volume for gas measurement shall be 1 cubic foot at a base temperature of 60°F and at a base pressure of 15.025 pounds per square inch absolute (psia) (14.73 psia for Pacific OCS Region), and the measurement unit shall be 1,000 cubic feet (Mcf) of gas.

(3) Gas meters shall be operated in accordance with the following requirements:

(i) The Minerals Management Service representatives shall be permitted to witness regularly scheduled calibrations and any calibration requested by the Regional Supervisor.

(ii) The integrity of the calibration equipment shall be in accordance with the standards in paragraph (c)(1) of this section.

(iii) Each gas meter shall be calibrated at reasonable intervals not to exceed 45 days. For positive displacement or turbine meters, the calibration shall be conducted at the average hourly rate of flow since the last calibration. For orifice meter installations, the differential range and static range shall be consistent with the hourly flow rate. The lessee shall retain calibration test data at the field location for a period of 2 years.

(iv) Whenever a meter is not functioning or not registering within the limits of accuracy prescribed by the manufacturer, it shall be immediately removed from service and not returned to service until repaired or adjusted to read accurately.

(v) During calibration, if readings of static and differential pressure are found to be within contractual tolerances with respect to test device readings, previous meter readings shall be considered correct in computing deliveries of gas since the previous calibration. If the readings are greater than contractural tolerances, the volume measured since the last calibration shall be corrected as follows:

(A) If the time the error occurred is ascertainable, the volume adjustment shall be calculated for that period of time. No retroactive adjustment of volumes metered for allocation beyond a 23-day period is required.

(B) If the time the error occurred is not ascertainable, the volume adjustment shall be applied to one-half of the time elapsed since the last date of calibration or 23 days, whichever is less.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60026, Nov. 26, 1996]

§ 250.182 Surface commingling of production.

(a) *General requirements.* For purposes of this subpart, surface commingling is the surface mixing of production from two or more leases prior to measurement for royalty purposes. The commingling of production from different leases prior to measurement for royalty sales determination shall be in accordance with this section.

(b) *Applications and approvals.* (1) The lessee shall not commence commingling of production unless the Regional Supervisor has approved the commingling and the method of measurement. The lessee shall submit an application for commingling to the Regional Supervisor for approval, and the application shall contain appropriate information regarding the method of allocation measurement, processing, if applicable, and the manner of entry into the particular commingling system.

(2) All allocation methods and procedures and changes thereto shall be approved by the Regional Supervisor.

(c) *Well tests.* The lessee shall conduct a well test for allocation purposes at least once every 2 months or other period of time as determined by the Regional Supervisor and shall retain test data at the field location for a period of 2 years. These tests are to be conducted in accordance with procedures outlined in § 250.173 of this part and can be used when submitting well tests as required in § 250.173.

§ 250.183 Site security.

All locations where oil, gas, or both are measured shall be operated and maintained to ensure against the loss or theft of production and to assure accurate measurement for royalty purposes. Production, transportation to shore, and sales activities shall comply with the following requirements:

(a) The components of sales measuring devices (metering units and tanks) shall be sealed in a manner to preclude tampering. Wire or other acceptable types of seals shall be numbered and recorded. The list of seal numbers and the installation location shall be maintained at the field location and be available for inspection by MMS representatives.

(1) The following metering and sampling unit components shall be sealed in such a manner that the component cannot be opened, closed, or altered in any way without destroying the seal:

(i) All meter stack component connections from the base of the stack to the register;

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

(iii) Components of the temperature and gravity compensation device;

(iv) Additional components as required by the Regional Supervisor;

(2) All valves on lines leaving an oil storage tank including load-out line valves, drain-line valves, and connection-line valves between sale and nonsale tanks shall be sealed in such a manner that the valve is closed and cannot be opened without destroying the seal.

(b) Each storage tank (sales or inventory) used in the royalty determination process shall be clearly identified by a sign that contains the name of the facility operator, the size of the tank, and the tank number.

(c) No one shall bypass MMS-approved royalty sales meters and sales tanks.

(d) Evidence of theft or mishandling of production from an offshore lease, or of tampering or bypassing with metering or proving devices, or of falsifying any measurement of production from an offshore lease shall be reported to the Regional Supervisor as soon as possible but not later than the next business day after discovery of evidence of theft or mishandling.

Subpart M—Unitization

SOURCE: 62 FR 5331, Feb. 5, 1997, unless otherwise noted.

§ 250.190 What is the purpose of this subpart?

This subpart explains how Outer Continental Shelf (OCS) leases are unitized. If you are an OCS lessee, use the regulations in this subpart for both competitive reservoir and unitization situations. The purpose of joint development and unitization is to:

(a) Conserve natural resources;

(b) Prevent waste; and/or

(c) Protect correlative rights, including Federal royalty interests.

§ 250.191 What are the requirements for unitization?

(a) *Voluntary unitization.* You and other OCS lessees may ask the Regional Supervisor to approve a request for voluntary unitization. The Regional Supervisor may approve the request for voluntary unitization if unitized operations:

(1) Promote and expedite exploration and development; or

(2) Prevent waste, conserve natural resources, or protect correlative rights, including Federal royalty interests, of a reasonably delineated and productive reservoir.

(b) *Compulsory unitization.* The Regional Supervisor may require you and other lessees to unitize operations if unitized operations are necessary to:

(1) Prevent waste;

(2) Conserve natural resources; or

(3) Protect correlative rights, including Federal royalty interests, of a reasonably delineated and productive reservoir.

(c) *Unit area.* The area that a unit includes is the minimum number of leases that will allow the lessees to minimize the number of platforms, facility installations, and wells necessary for efficient exploration, development, and production of mineral deposits, oil and gas reservoirs, or potential hydrocarbon accumulations. A unit may include whole leases or portions of leases.

(d) *Unit agreement.* You, the other lessees, and the unit operator must enter into a unit agreement. The unit agreement must: allocate benefits to unitized leases, designate a unit operator, and specify the effective date of the unit agreement. The unit agreement must terminate when: the unit no longer produces unitized substances, and the unit operator no longer conducts drilling or well-workover operations (§ 250.13) under the unit agreement, unless the Regional Supervisor orders or approves a suspension of production under § 250.10.

(e) *Unit operating agreement.* The unit operator and the owners of working interests in the unitized leases must enter into a unit operating agreement. The unit operating agreement must describe how all the unit participants will apportion all costs and liabilities incurred maintaining or conducting operations. When a unit involves one or more net-profit-share leases, the unit operating agreement must describe how to attribute costs and credits to the net-profit-share lease(s), and this part of the agreement must be approved by the Regional Supervisor. Otherwise, you must provide a copy of the unit operating agreement to the Regional Supervisor, but the Regional Supervisor does not need to approve the unit operating agreement.

(f) *Extension of a lease covered by unit operations.* If your unit agreement expires or terminates, or the unit area adjusts so that no part of your lease remains within the unit boundaries, your lease expires unless:

(1) Its initial term has not expired;

(2) You conduct drilling, production, or well-reworking operations on your lease consistent with applicable regulations; or

(3) MMS orders or approves a suspension of production or operations for your lease.

(g) *Unit operations.* If your lease, or any part of your lease, is subject to a unit agreement, the entire lease continues for the term provided in the lease, and as long thereafter as any portion of your lease remains part of the unit area, and as long as operations continue the unit in effect.

(1) If you drill, produce or perform well-workover operations on a lease within a unit, each lease, or part of a lease, in the unit will remain active in accordance with the unit agreement. Following a discovery, if your unit ceases drilling activities for a reasonable time period between the delineation of one or more reservoirs and the initiation of actual development drilling or production operations and that time period would extend beyond your lease's primary term or any extension under § 250.13, the unit operator must request and obtain MMS approval of a suspension of production under § 250.10 in order to keep the unit from terminating.

(2) When a lease in a unit agreement is beyond the primary term and the lease or unit is not producing, the lease will expire unless:

(i) You conduct a continuous drilling or well reworking program designed to develop or restore the lease or unit production; or

(ii) MMS orders or approves a suspension of operations under § 250.10.

§ 250.192 What if I have a competitive reservoir on a lease?

(a) The Regional Supervisor may require you to conduct development and production operations in a competitive reservoir under either a joint Development and Production Plan or a unitization agreement. A competitive reservoir has one or more producing or producible well completions on each of two or more leases, or portions of leases, with different lease operating interests. For purposes of this paragraph, a producible well completion is a well which is capable of production and which is shut in at the well head or at the surface but not necessarily connected to production facilities and from which the operator plans future production.

(b) You may request that the Regional Supervisor make a preliminary determination whether a reservoir is competitive. When you receive the preliminary determination, you have 30 days (or longer if the Regional Supervisor allows additional time) to concur or to submit an objection with supporting evidence if you do not concur. The Regional Supervisor will make a final determination and notify you and the other lessees.

(c) If you conduct drilling or production operations in a reservoir determined competitive by the Regional Supervisor, you and the other affected lessees must submit for approval a joint plan of operations. You must submit the joint plan within 90 days after the Regional Supervisor makes a final determination that the reservoir is competitive. The joint plan must provide for the development and/or production of the reservoir. You may submit supplemental plans for the Regional Supervisor's approval.

(d) If you and the other affected lessees cannot reach an agreement on a joint Development and Production Plan within the approved period of time, each lessee must submit a separate plan to the Regional Supervisor. The Regional Supervisor will hold a hearing to resolve differences in the separate plans. If the differences in the separate plans are not resolved at the hearing and the Regional Supervisor determines that unitization is necessary under § 250.191(b), MMS will initiate unitization under § 250.194.

§ 250.193 How do I apply for voluntary unitization?

(a) You must file a request for a voluntary unit with the Regional Supervisor. Your request must include:

(1) A draft of the proposed unit agreement;

(2) A proposed initial plan of operation;

(3) Supporting geological, geophysical, and engineering data; and

(4) Other information that may be necessary to show that the unitization proposal meets the criteria of § 250.190.

(b) The unit agreement must comply with the requirements of this part. MMS will maintain and provide a model unit agreement for you to follow. If MMS revises the model, MMS will publish the revised model in the FEDERAL REGISTER. If you vary your unit agreement from the model agreement, you must obtain the approval of the Regional Supervisor.

(c) After the Regional Supervisor accepts your unitization proposal, you, the other lessees, and the unit operator must sign and file copies of the unit agreement, the unit operating agreement, and the initial plan of operation with the Regional Supervisor for approval.

§ 250.194 How will MMS require unitization?

(a) If the Regional Supervisor determines that unitization of operations within a proposed unit area is necessary to prevent waste, conserve natural resources of the OCS, or protect correlative rights, including Federal royalty interests, the Regional Supervisor may require unitization.

(b) If you ask MMS to require unitization, you must file a request with the Regional Supervisor. You must include a proposed unit agreement as described in §§ 250.191(d) and 250.193(b); a proposed unit operating agreement; a proposed initial plan of operation; supporting geological, geophysical, and engineering data; and any other information that may be necessary to show that unitization meets the criteria of § 250.190. The proposed unit agreement must include a counterpart executed by each lessee seeking compulsory unitization. Lessees who seek compulsory unitization must simultaneously serve on the nonconsenting lessees copies of:

(1) The request;

(2) The proposed unit agreement with executed counterparts;

(3) The proposed unit operating agreement; and

(4) The proposed initial plan of operation.

(c) If the Regional Supervisor initiates compulsory unitization, MMS will serve all lessees of the proposed unit area with a proposed unitization plan and a statement of reasons for the proposed unitization.

(d) The Regional Supervisor will not require unitization until MMS provides all lessees of the proposed unit area written notice and an opportunity for a hearing. If you want MMS to hold a hearing, you must request it within 30 days after you receive written notice from the Regional Supervisor or after you are served with a request for compulsory unitization from another lessee.

(e) MMS will not hold a hearing under this paragraph until at least 30 days after MMS provides written notice of the hearing date to all parties

owning interests that would be made subject to the unit agreement. The Regional Supervisor must give all lessees of the proposed unit area an opportunity to submit views orally and in writing and to question both those seeking and those opposing compulsory unitization. Adjudicatory procedures are not required. The Regional Supervisor will make a decision based upon a record of the hearing, including any written information made a part of the record. The Regional Supervisor will arrange for a court reporter to make a verbatim transcript. The party seeking compulsory unitization must pay for the court reporter and pay for and provide to the Regional Supervisor within 10 days after the hearing three copies of the verbatim transcript.

(f) The Regional Supervisor will issue an order that requires or rejects compulsory unitization. That order must include a statement of reasons for the action taken and identify those parts of the record which form the basis of the decision. Any adversely affected party may appeal the final order of the Regional Supervisor under 30 CFR part 290.

Subpart N—Remedies and Penalties

§ 250.200 Remedies.

(a)(1) Whenever the Regional Director determines, on the basis of available evidence, that a violation of or failure to comply with any provision of the Outer Continental Shelf Lands Act (Act), or any provision of a lease, license, or permit issued pursuant to the Act, or any provision of any regulation issued under the Act (hereinafter referred to as ''violation'') probably occurred and that such violation continued beyond actual notice of the violation and the expiration of any reasonable period allowed for corrective action or that the violation may constitute or may have constituted a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment, the Regional Director may direct the preparation of a case file, and appoint a Minerals Management Service (MMS) employee to serve as a Reviewing Officer. In making this determination, the Regional Director shall have the authority to summon witnesses, administrator oaths, and issue orders to produce evidence. Chairmen of investigative panels appointed by the Regional Director to investigate violations or other matters shall also have authority to summon witnesses, administer oaths, and issue orders to produce evidence while conducting investigations.

(2) The Reviewing Officer shall have no other responsibility, direct or supervisory, for the investigation or prosecution of the case.

(3) The Reviewing Officer shall decide each case on the basis of the evidence of record.

(4) The Reviewing Officer may administer oaths and issue subpoenas requiring the attendance of witnesses at hearings or for the taking of depositions and may issue orders to produce evidence.

(5) The Reviewing Officer may assess civil penalties and, when appropriate, recommend the initiation of criminal proceedings.

(b) The Reviewing Officer shall proceed with provisions of paragraph (c) of this section upon determining that there is sufficient evidence that a violation probably occurred and that:

(1) The violation continued beyond any notice of such failure and the expiration of any reasonable period allowed for corrective action, or

(2) The violation constitutes or constituted a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment.

(c) The Reviewing Officer shall notify, in writing, the person alleged to have committed the violation (hereinafter referred to as ''party'') of the following:

(1) The alleged violation, citing the applicable provision of the Act, or the applicable term of a lease, license, or permit issued pursuant to the Act, or the applicable provision of a regulation or order issued under the Act upon which the action is based;

(2) The amount of penalty that appears to be appropriate in the event it is determined that the party is responsible for the alleged violation based upon the material then available for the Reviewing Officer;

(3) The party's right to examine the material in the case file and to have a copy of all written documents provided upon request, except those which would, in a civil proceeding, disclose or lead to the disclosure of a confidential informant; and

(4) The fact that, subject to the provisions in § 250.201 of this part, the party has a right to a hearing before the Reviewing Officer prior to any finding of fact regarding the alleged violation.

(d) A party has the right to be represented by counsel, qualified to practice before the Department of the Interior (DOI) under 43 CFR part 1, at all stages of the proceeding. After receiving notification that a party is represented by counsel, the Reviewing Officer shall direct all further communications to the counsel.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 21954, May 13, 1991]

§ 250.201 Hearings.

(a) Within 30 days after receipt of a notice pursuant in § 250.200(b) of this part, the party may accomplish one of the following:

(1) Request a hearing before the Reviewing Officer,

(2) Provide any written evidence and arguments in lieu of a hearing, or

(3) Pay the amount specified in the notice.

(b) A request for a hearing before the Reviewing Officer shall be in writing and specify the particular issues which are in dispute. Failure to specify a nonjurisdictional issue will preclude its consideration except as the Reviewing Officer determines to be necessary or desirable in the interest of obtaining a fair resolution of the case.

(1) The Reviewing Officer may grant the party additional time to submit a request for a hearing.

(2) The Reviewing Officer shall promptly schedule all requested hearings to be held in the office of the Reviewing Officer or such other location as the Reviewing Officer may designate. The Reviewing Officer shall grant any delays or continuances which the Reviewing Officer determines to be necessary or desirable in the interest of obtaining a fair resolution of the case.

(c) Prior to a hearing, the party may examine all evidence in the case file except material that would disclose or lead to the disclosure of the identity of a confidential informant.

(d)(1) Confidential treatment shall be accorded to all or a portion of any document at the request of the person supplying the information if the information is as follows:

(i) Confidential financial information, trade secrets, or other material exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552);

(ii) Information required to be held in confidence by these regulations; or

(iii) Information that is otherwise exempt by law from disclosure.

(2) The person desiring confidential treatment of information shall submit a written request to the Reviewing Officer stating the reasons justifying nondisclosure.

(e) The Regional Director may, upon request of a party, transfer the case to another Reviewing Officer or direct that the hearing be held at a location other than that specified by the Reviewing Officer.

(f)(1) The testimony of any witness may be presented either through a personal appearance or through a written statement.

(2) A witness may be required to attend a hearing or the taking of a deposition at a place not more than 100 miles from the place of service.

(3) Witnesses subpoenaed shall be paid the same fees and mileage paid for similar services in the U.S. District Courts. These expenses shall be paid by the party at whose insistence the witness appears.

(4) Any witness who attends a hearing or the taking of a deposition at the request of the party, without having been subpoenaed to do so, shall be entitled to the same mileage and attendance fees paid to a subpoenaed witness. The witness fees and mileage shall be paid by the party at whose request the witness appears.

(5) In cases where an individual cannot be required to appear as a witness, the Reviewing Officer may move the hearing to the location of the desired witness, accept a written statement, or accept a stipulation in lieu of testimony.

§ 250.202 Hearing procedures.

(a) Material in the case file which is pertinent to the issues shall be presented to the party who may respond to or rebut this material. The party may offer any facts, statements, explanations, documents, sworn or unsworn testimony, or other items which bear on the issues or which may be relevant to the amount of the penalty to be assessed if the party is found to be guilty of the alleged violation. The Reviewing Officer may require the authentication of any written exhibit or statement.

(b) The party may request an opportunity to submit additional written testimony for consideration by the Reviewing Officer. The Reviewing Officer shall allow a reasonable time for submission of additional written testimony and shall specify the date by which it must be received.

(c) The Reviewing Officer may take notice of matters which are subject to a high degree of indisputability and are commonly known in the community or are ascertainable from readily available sources of known accuracy. Prior to taking notice of a matter, the Reviewing Officer shall give the party an opportunity to show why notice should not be taken. In any case in which such notice is taken, the Reviewing Officer shall place in the record a written statement on the matter of which notice was taken and the basis for taking such notice. The Reviewing Officer's statement shall indicate that the party consented to notice being taken or shall include a summary of the party's objections to notice being taken of a specific matter.

(d) In evaluating the evidence presented, the Reviewing Officer shall give due consideration to the reliability and relevance of each item of evidence but is not bound by strict rules of evidence.

(e)(1) A verbatim transcript of hearings before a Reviewing Officer need not be prepared. The Reviewing Officer shall prepare notes on the material and points raised by the party in sufficient detail to permit a full and fair review and resolution of the case should it be appealed.

(2) A party may, at its own expense, cause a verbatim transcript to be made. If a verbatim transcript is made and the Reviewing Officer's decision is appealed, the party shall submit a copy of the verbatim transcript with the appeal to the Director and to the Reviewing Officer for inclusion in the case file.

§ 250.203 Reviewing Officer's decision.

(a) The Reviewing Officer's decision shall be in writing and shall include the Reviewing Officer's conclusions and the basis for the conclusions. Any decision shall be based upon substantial evidence in the record. The Reviewing Officer shall dismiss the case and remand it to the Regional Director if the Reviewing Officer finds that:

(1) There is not substantial evidence in the record establishing that the alleged violation occurred,

(2) For a violation under § 250.200(b)(1) of this part, either the required notice of the alleged violation was not provided or that the alleged violation did not continue after the termination of any period provided for the taking of corrective action, or

(3) For a violation under § 250.200(b)(2) of this part, there is not substantial evidence on the record that, at the time of the discovery of the violation or during a time prior to the discovery of the violation, the violation constituted a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment.

(b) A dismissal under paragraph (a) of this section is without prejudice to the Regional Director's right to refile the case and have it reheard if additional evidence is obtained. A dismissal following a rehearing is final and with prejudice.

(c) The Reviewing Officer's decision shall contain a statement advising the party of the right to an administrative appeal to the Director pursuant to 30 CFR part 290 of this title. The party shall be advised that failure to submit

an appeal within the prescribed time will bar its consideration and that failure to appeal on the basis of a particular issue will constitute a waiver of that issue in any subsequent proceeding. An appeal from any interim ruling of the Reviewing Officer shall be reserved and considered only at the time of and as part of an appeal from the Reviewing Officer's final decision.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 21955, May 13, 1991]

§ 250.204 Appeals from Reviewing Officer's decision.

(a)(1) Any appeal from a decision of the Reviewing Officer, together with any supporting argument, shall be submitted by a party to the Director within 30 days after the date of receipt of the decision. The appellant shall provide a copy of the notice of appeal and supporting brief to the Reviewing Officer. Except as provided in § 250.205 of this part, the only issues which will be considered on appeal are jurisdictional questions and those issues specified in the notice of appeal which were properly raised before the Reviewing Officer.

(2) The failure to file a notice of appeal within the time prescribed shall result in the action of the Reviewing Officer becoming the final action of the DOI in the case.

(b) A copy of all of the Reviewing Officer's comments on the appeal submitted to the Director shall be provided to the appellant.

(c)(1) The Director may affirm, reverse, or modify the Reviewing Officer's decision or remand the case for new or additional proceedings.

(2) The Director may increase, remit, mitigate, or suspend, in whole or in part, any penalty assessed by the Reviewing Officer.

(d) The Director's decision shall be in writing, and copies shall be provided to the appellant and the Reviewing Officer.

(e) In the absence of an appeal from the Director's decision pursuant to 30 CFR part 290, the Director's decision on an appeal shall be final. (See § 250.24 of this part.)

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989]

§ 250.205 Reopening a case.

(a)(1) At any time prior to final MMS action in a civil-penalty case, a party may petition to reopen the proceedings on the basis of newly discovered evidence.

(2) Petitions to reopen a case must be in writing. Petitions shall describe the newly found evidence and state why the evidence would probably produce a different result favorable to the petitioner. The petitioner shall state whether the evidence was known to the petitioner at the time of the proceedings and, if not, why the newly found evidence could not have been discovered during the previous proceedings. The party shall submit the petition to the Reviewing Officer and provide a copy to the Regional Director.

(3) The Reviewing Officer shall consider a petition to reopen a case unless an appeal has been filed. In those cases where an appeal has been timely filed, a petition to reopen a case shall be considered by the Director.

(4) A petition to reopen a case shall be granted only when the Reviewing Officer or Director determines that the petition explains why newly found evidence that would have a direct and material bearing on the issue(s) of the case was not and could not have been produced at the time of the previous proceedings. A decision on a petition to reopen a case shall be in writing. A new decision issued by the Reviewing Officer, on the basis of newly found evidence, may be appealed to the Director in accordance with § 250.204 of this part.

(b) The denial of a petition to reopen a case shall be final and may not be appealed in an action separate from the appeal of the case pursuant in § 250.204 of this part or 30 CFR part 290 of this title.

(c) The Regional Director may, on the basis of newly found evidence, that would probably produce a different result, reopen a case pursuant to § 250.203(a) of this part.

§ 250.206 Civil penalties.

(a)(1) If the Reviewing Officer determines that a civil penalty is to be assessed, the penalty shall not exceed $20,000 for each day of the continuation of the violation. For violations described in § 250.200(b)(1) of this part, the

penalty may be assessed for each day the violation continues after notice and a reasonable period for corrective action. For violations described in § 250.200(b)(2) of this part, the penalty may be assessed for each day the violation continued after it first occurred.

(2) If the Reviewing Officer's decision is appealed to the Director, payment of a civil-penalty shall not be due until after the Director's decision on the appeal is issued. If administrative relief is pursued following the Director's decision, a bond guaranteeing payment may be posted in lieu of actual payment.

(3) The MMS's Associate Director for Royalty Management shall collect civil-penalties assessed by a Reviewing Officer, the Director, or DOI's Board of Land Appeals.

(4) Payment of a civil-penalty shall be in accordance with instructions that accompany the Bill for Collection (Form DI–1040) sent to the party upon whom the penalty is imposed.

(b) Within 30 days after receipt of the bill issued by MMS's Royalty Management Program Accounting Division, the party shall submit payment of the assessed penalty to MMS's Accounting Center unless an appeal is filed in accordance with § 250.204 of this part. Failure to either make timely payment or file a timely appeal will result in the collection of the amount assessed plus interest from the date of assessment until the date of payment as determined by MMS. Interest shall be computed on a daily basis at the rate applicable under section 6621 of the Internal Revenue Code of 1954. Such failure may also result in the initiation of additional enforcement proceedings including, if appropriate, cancellation of the lease or permit or forfeiture of a bond under this part.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 56 FR 21955, May 13, 1991]

Subpart O—Training

SOURCE: 62 FR 5322, Feb. 5, 1997, unless otherwise noted.

§ 250.209 Question index table.

The table in this section lists frequently asked training questions and the location for the answers. The subjects are grouped as follows:

(a) General training requirements—§§ 250.211 through 250.216.

(b) Departures from training requirements—§§ 250.217 through 250.222.

(c) Training program accreditations—§§ 250.223 through 250.229 and § 250.233.

(d) MMS testing information—§§ 250.230 through 250.232.

Frequently asked questions	CFR citation
What is MMS's goal for well control and production safety systems training?	§ 250.211
What type of training must I provide for my employees?	§ 250.212
What documentation must I provide to trainees?	§ 250.213
How often must I provide training to my employees and for how many hours?	§ 250.214
Where must I get training for my employees?	§ 250.215
Where can I find training guidelines for other topics?	§ 250.216
Can I get an exception to the training requirements?	§ 250.217
Can my employees change job certification?	§ 250.218
What must I do if I have temporary employees or on-the-job trainees?	§ 250.219
What must manufacturer's representatives in production safety systems do?	§ 250.220
May I use alternative training methods?	§ 250.221
What is MMS looking for when it reviews an alternative training program?	§ 250.222
Who may accredit training organizations to teach?	§ 250.223
How long is a training organization's accreditation valid?	§ 250.224
What informaiton must a training organization submit to MMS?	§ 250.225
What additional requirements must a training organization follow?	§ 250.226
What are MMS's requirements for the written test?	§ 250.227
What are MMS's requirements for the hands-on simulator and well test?	§ 250.228
What elements must a basic course cover?	§ 250.229
If MMS tests employees at my worksite, what must I do?	§ 250.230
If MMS tests trainees at a training organization's facility, what must occur?	§ 250.231
Why might MMS conduct its own tests?	§ 250.232
Can a training organization lose its accreditation?	§ 250.233

§ 250.210 Definitions.

Terms used in this subpart have the following meaning:

Alternative training methods means self-paced or team-paced training that may use a computer-based system such as compact disc interactive (CDI), compact disc read only memory (CDROM), or Laser Discs.

Completed training means that the trainee successfully met MMS's requirements for that training.

Employees means direct employees and contract employees of lessees.

Floorhands means rotary helpers, derrickmen, or their equivalent.

I or *you* means the lessee or contractor engaged in oil, gas or sulphur operations in the Outer Continental Shelf (OCS).

Installing means both installing the original equipment and replacing the equipment.

Lessee means the person, organization, agent, or designee authorized to explore, develop, and produce leased deposits.

Maintaining means preventive maintenance, routine repair, and replacing defective components.

Operating means testing, adjusting, calibrating, and recording test and calibration results for the equipment.

Production safety systems employee means employees engaged in installing, repairing, testing, maintaining, or operating surface or subsurface safety devices and the platform employee who is responsible for production operations.

Supervisors means the driller, toolpusher, operator's representative, or their equivalent.

Training means a basic or an advanced class in well control for drilling, well completion/well workover, well servicing, and production safety systems.

Training organization means a party approved by MMS to teach well control for drilling, well completion/well workover, and well servicing, and production safety systems.

Well-completion/well-workover (WO) well control includes small tubing operations.

Well-servicing (WS) well control means snubbing and coil tubing.

Well-workover rig means a drilling rig used for well completion/well workover.

§ 250.211 What is MMS's goal for well control and production safety systems training?

The goal is to ensure that employees who work in the following areas receive training that results in safe and clean operations:

(a) Drilling well control;

(b) WO well control;

(c) WS well control; and

(d) Production safety systems.

§ 250.212 What type of training must I provide for my employees?

You must provide training for your employees according to the table in this section.

Type of employee	Training requirements	Comments
Drilling floorhand	Drilling well-control course.[1]	
	Complete a well-control drill at the job site within the time limit prescribed by company operating procedures.[2].	You must log the time it took to complete each drill in the driller's log and furnish the time to the floorhand.
	Participate in well-control drills under subpart D of this part.[2].	You must record the date and time it took to complete each drill in the driller's log.
	Receive copy of a drilling well-control manual.[2]	
Drilling supervisor	Drilling well-control course.[1]	
	Qualify to direct well-control operations.[1]	
WO floorhands	WO well-control course.[1]	
	Complete the qualifying test consisting of a well-control drill at the job site within the time limit set by company procedures.[2].	You must record the date and time it took to complete each drill in the operations log.
	Participate in weekly well-control drills under subparts E and F of this part.[2]	
	Receive a well-control manual.[2]	
WO supervisors	WO well-control course.[1]	
	Qualify to direct well-control operations.[1]	
WS work crews	At least one crew member is trained in WS well control.[1].	Trained employee must be in work area at all times during snubbing or coil tubing operations.

Type of employee	Training requirements	Comments
Production safety systems employees.	At least one crew member must be qualified to direct well-control operations.[1] Must complete training that enables them to install, test, maintain, & operate subsurface safety devices.[1]	
Employees who work in well completion operations before or during tree installation.	Either WO well-control course or drilling well-control course.[1]	

[1] Employee may not work in the OCS unless this requirement is met.
[2] Employee must complete this requirement before exceeding 6 months of cumulative employment.

§ 250.213 What documentation must I provide to trainees?

You must give your employees documents that show they have completed the training course(s) required for their job. The employees must carry the documents or keep them at the job site.

§ 250.214 How often must I provide training to my employees and for how many hours?

(a) You must ensure that applicable employees complete basic or advanced well-control training at least every 2 years. For example, if your employees complete a well-control course on October 31, 1998, they must again complete the training by October 31, 2000.

(b) You must ensure that applicable employees complete basic or advanced production safety systems training at least every 3 years. For example, if your employees complete production safety systems training on October 31, 1998, they must again complete the training by October 31, 2001.

(c) You must ensure that your employees have at least the amount of training listed in the table in § 250.214(c). The maximum number of hours per day of well control or production safety instruction time is 9 hours.

TRAINING HOURS

Basic/advanced course	Surface option, minimum hours	Subsea option, minimum hours[1]	No options, minimum hours
Drilling (D)	28	32	.....
Well Completion/Workover (WO)	32	36	.....
Well Servicing (WS)	.....	.....	18
Combination D/WO	40	44	.....
Combination D/WS	44	48	.....
Combination WO/WS	48	52	.....
Combination D/WO/WS	55	59	.....
Production Safety Systems	.....	.....	30

[1] The subsea option includes the minimum hours from the surface option plus 4 hours.

(d) For the first training course after March 7, 1997, you must ensure that your employee follows the following transition schedule table for well control.

WELL CONTROL TRANSITION

If your employees	Then the employees must
A. Completed a basic course on or after March 7, 1996 or	A. Complete an appropriate basic course within 2 years to maintain certification,[1] or
B. Completed a basic course before March 7, 1996.	B. Complete an appropriate basic course by March 9, 1998 .[2]

[1] Example A: If the effective date of this regulation is November 1, 1996, and your employees completed a basic course in Drilling and Workover/Completion well control on December 9, 1995, your employees must complete a basic Drilling and Workover/Completion well-control course by December 9, 1997.
[2] Example B: If the effective date of this regulation is November 1, 1996, and your employees completed a basic course in Well Servicing [snubbing option] well control on November 15, 1994, your employees must complete a basic course in Well Servicing [snubbing option] by November 1, 1997.

(e) For the first training course after March 7, 1997, you must ensure that your employee follows the following transition schedule table for production.

PRODUCTION TRANSITION

If your employees	Then your employees must
A. Completed a basic course on or after September 7, 1995, or	A. Complete a basic course within 3 years to maintain certification, or
B. Completed a basic course before September 7, 1995.	B. Complete a basic course by September 7, 1998.

(f) After your employee completes the transition training specified in paragraph (d) or (e) of this section, the training cycle will be 2 years for well control and 3 years for production training (as shown in § 250.214 (a) and (b)).

[62 FR 5323, Feb. 5, 1997, as amended at 62 FR 7298, Feb. 18, 1997]

§ 250.215 Where must I get training for my employees?

You must provide training by a training organization or program approved by MMS.

§ 250.216 Where can I find training guidelines for other topics?

You can find guidelines in the subparts shown in the following table:

Topic	Subpart of part 250
Pollution control	C
Crane operations	A
Welding and burning	D
Hydrogen sulfide	D

§ 250.217 Can I get an exception to the training requirements?

MMS may grant an exception to well control or production safety systems training if:

(a) MMS determines that the exception won't jeopardize the safety of your personnel or create a hazard to the environment; and

(b) You need the exception because of unavoidable circumstances that make compliance infeasible or impractical.

§ 250.218 Can my employees change job certification?

Only if you ensure that the employees complete training for the new job before entering on duty.

§ 250.219 What must I do if I have temporary employees or on-the-job trainees?

You must ensure that temporary employees and on-the-job trainees complete the appropriate training unless a trained individual is directly supervising the employee.

§ 250.220 What must manufacturer's representatives in production safety systems do?

A manufacturer's representative who is working on company supplied equipment must:

(a) Receive training by the manufacturer to install, service, or repair the specific safety device or safety systems; and

(b) Have an individual trained in production safety systems (who is also capable of evaluating the impact of the work done) accompany her/him.

§ 250.221 May I use alternative training methods?

(a) You may receive a 1-year provisional approval from MMS to use alternative training methods that may involve team or self-paced training using a computer-based system.

(b) You may receive up to 3 additional years (4 years total) from MMS to use alternative training methods (through onsite reviews).

§ 250.222 What is MMS looking for when it reviews an alternative training program?

(a) The alternative training must teach methods to operate equipment that result in safe and clean operations.

(b) MMS will determine, through onsite MMS reviews and unannounced audits during the provisional period, if the:

(1) Training environment is conducive to learning;

(2) Trainees interact effectively with the moderator or training administrator,

(3) Trainees function as a team (for well control only); and

(4) Tests are challenging and cover all important safety concepts and practical procedures to ensure safety.

(c) MMS may also speak with the trainees to determine if the trainees felt the training met their needs for their job.

§ 250.223 Who may accredit training organizations to teach?

MMS may accredit a training organization or program.

§ 250.224 How long is a training organization's accreditation valid?

An accreditation is valid for a maximum of 4 years. A training organization may apply to MMS before the fourth anniversary of the effective accreditation date. The training organization must state the changes (additions and deletions) to the last approved training curriculum and plan.

§ 250.225 What information must a training organization submit to MMS?

(a) Two copies of the detailed plan that includes the:

(1) Curriculum;

(2) Names and credentials of the instructors;

(3) Mailing and street address of the training facility and the location of the records;

(4) Location for the simulator and lecture areas and how the training organization separates the areas;

(5) Presentation methods (video, lecture, film, etc.);

(6) Percentage of time for each presentation method;

(7) Testing procedures and a sample test; and

(8) List of any portions of the course that cover the subsea training option instead of the surface training option.

(b) Two copies of the training manual.

(c) A cross-reference that relates the requirements of this supbart to the elements in the program.

(d) A copy of the handouts.

(e) A copy of the training certificate that includes the following:

(1) Candidate's full name;

(2) Candidate's social security number,

(3) Name of the training school;

(4) Course name (e.g., basic WS well-control course);

(5) Option (surface or subsea);

(6) Training completion date;

(7) Job classification (e.g., drilling supervisor); and

(8) Certificate expiration date.

(f) Course outlines identified by:

(1) Name (e.g., ''WS well-control course'');

(2) Type (basic or advanced); and

(3) Option (surface or subsea).

(g) Time (hours per student) for the following:

(1) Teaching;

(2) Using the simulator (for well control);

(3) Hands-on training (for production safety systems); and

(4) Completing the test (written and simulator).

(h) Special instruction methods for students who respond poorly to conventional training (including oral assistance).

(i) Additional materials (for the advanced training option) such as advanced training techniques or case studies.

(j) Information on the 3–D simulator or test wells:

(1) Capability for surface and/or subsea drilling well control, WO and completion training;

(2) Capability to simulate lost circulation and secondary kicks; and

(3) Types of kicks.

§ 250.226 What additional requirements must a training organization follow?

(a) The training organization must keep training records for each trainee for 5 years. For example, if a trainee completed a well-control course in 1996, the training organization may destroy the records at the end of the year 2001. The training organization must keep the following trainee record information:

(1) Daily attendance record including complete student sign-in sheet and makeup time;

(2) Written test and retest (including simulator test);

(3) Evaluation of the trainee's simulator test or retest;

(4) ''Kill sheets'' for simulator test or retest; and

(5) Copy of the trainee's certificate.

(b) Keep records of the training program for 5 years. The 5-year timeframe starts with the program approval date. For example, if a training program was accredited in 1995, at the end of the year 2000, the training organization may destroy the records for 1995. Keep the following training record information:

(1) Complete and current training program plan and a technical manual;

(2) A copy of each class roster; and

(3) Copies of schedules and schedule changes.

(c) Supply trainees with current copies of Government regulations on the training subject matter.

(d) Provide a certificate to each trainee who successfully completes training.

(e) Ensure that the subsea training option has an additional 4 hours of training and covers problems in well control when drilling with a subsea blowout preventer (BOP) stack including:

(1) Choke line friction determinations;

(2) Using marine risers;

(3) Riser collapse;

(4) Removing trapped gas from the BOP after controlling a well kick; and

(5) ''U'' tube effect as gas hits the choke line.

(f) Ensure that trainees who are absent from any part of a course make up the missed portion within 14 days after the end of the course before providing a written or simulator test to the trainee.

(g) Ensure that classes contain 18 or fewer candidates.

(h) Furnish a copy of the training program and plan to MMS personnel for their use during an onsite review.

(i) Submit the course schedule to the approving organization after approval of the training program, annually, and before any program changes. The schedule must include the:

(1) Name of the course;

(2) Class dates;

(3) Type of course; and

(4) Course location.

(j) Provide all basic course trainees a copy of the training manual.

(k) Provide all advanced course trainees handouts necessary to update the manuals the trainee has as a result of previous training courses.

(l) When each course ends, send MMS a letter and a class roster. The class roster must contain the following information for each trainee:

(1) Name of training organization;

(2) Course location (e.g., Thibodeaux, Louisiana);

(3) Trainee's full name;

(4) Name of course (e.g., Drilling well control or WS well control);

(5) Course type (i.e., basic or advanced training);

(6) Options (e.g., subsea);

(7) Date trainee completed course;

(8) Name(s) of instructor(s) teaching the course;

(9) The trainee's social security number;

(10) Trainee's employer;

(11) Actual job title of trainee;

(12) Job of each awarded certificate; and

(13) Test scores (including course element scores) for each successful trainee.

(m) Ensure that test scores for combination training have a separate score element for each designation and for each option. For example, training in subsea drilling and in WO would have separate test scores for the drilling, WO, and for the subsea portion.

§ 250.227 What are MMS's requirements for the written test?

(a) The training organization must:

(1) Administer the test at the training facility;

(2) Use 70 percent as a passing grade for each course element (drilling, well completion, etc.);

(3) Ensure that the tests are confidential and nonrepetitive;

(4) Offer a retest, when necessary, using different questions of equal difficulty;

(5) Allow open-book regulations and a formula sheet (without examples) for well control only; and

(6) Allocate no more than the following amount of time to the minimum instruction time: 1 hour for a single course, 2 hours for a combination of two basic courses, or 2.5 hours for a combination of three or more courses.

(b) A trainee who fails a retest must repeat the training and pass the test in order to work in the OCS in their job classification.

§ 250.228 What are MMS's requirements for the hands-on simulator and well test?

(a) The training organization must ensure that:

(1) The test simulates a surface BOP (or subsea stack for the subsea option) and the simulator is 3–D with actual gauges and dials.

(2) The instructor runs only one simulator and has a maximum of three students in each team.

(3) The simulator test time allocated to the minimum instruction time is 1 hour per course (i.e., 2 hours for a combination of two basic courses, etc.).

(4) The trainees are able to:

(i) Kill the well before removing the tree;

(ii) Determine slow pump rates;

(iii) Recognize kick warnings signs;

(iv) Shut in a well;

(v) Complete kill sheets;

(vi) Initiate kill procedures;

(vii) Maintain appropriate bottomhole pressure;

(viii) Maintain constant bottomhole pressure;

(ix) Recognize and handle unusual well-control situations;

(x) Control the kick as it reaches the choke line; and

(xi) Determine if kick gas or fluids are removed.

(5) In the subsea option, the trainees are able to:

(i) Determine choke line friction pressures for subsea BOP stacks; and

(ii) Discuss and demonstrate procedures such as circulating the riser and removing trapped gas in a subsea BOP stack.

(6) Offer a retest, when necessary, using different questions of equal difficulty.

(b) A trainee who fails a retest must repeat the training and pass the test to work in the OCS in their job classification.

[62 FR 5326, Feb. 5, 1997, as amended at 62 FR 7298, Feb. 18, 1997]

§ 250.229 What elements must a basic course cover?

See Table (a) of this section for well control and Table (b) of this section for production safety systems. The checks in Table (a) indicate the required training elements that apply to each job. Tables (a) and (b) follow:

TABLE (a).—WELL CONTROL

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
1. Hands-on:					
Training to operate choke manifold		✔		✔	
Training to operate stand pipe		✔		✔	
Training to operate mud room valves		✔			
2. Care, handling & characteristics of drilling & completion fluids.	✔	✔			
3. Care, handling & characteristics of well completion/well workover fluids & packer fluids.			✔	✔	✔
4. Major causes of uncontrolled fluids from a well including:					
Failure to keep the hole full	✔		✔		
Swabbing effect	✔		✔		
Loss of circulation	✔		✔		
Insufficient drilling fluid density	✔		✔		
Abnormally pressured formations	✔		✔		
Effect of too rapidly lowering of the pipe in the hole	✔		✔		
5. Importance & instructions of measuring the volume of fluid to fill the hole during trips.	✔		✔		
6. Importance & instructions of measuring the volume of fluid to fill the hole during trips including the importance of filing the hole as it relates to shallow gas conditions.	✔				

TABLE (a).—WELL CONTROL—Continued

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
7. Filling the tubing & casing with fluid to control bottomhole pressure.				✔	
8. Warning signals that indicate kick & conditions that lead to a kick.	✔	✔	✔	✔	
9. Controlling shallow gas kicks and using diverters	✔				
10. At least one bottomhole pressure well control method including conditions unique to a surface subsea BOP stack.	✔		✔		
11. Installing, operating, maintaining & testing BOP & diverter systems.	✔				
12. Installing, operating, maintaining & testing BOP systems.			✔		
13. Government regulations on:					
Emergency shutdown systems					✔
Production safety systems					✔
Drilling procedures	✔				
Wellbore plugging & abandonment	✔		✔		✔
Pollution prevention & waste management	✔	✔	✔	✔	✔
Well completion & well workover requirements (Subparts E & F of 30 CFR part 250).			✔		✔
14. Procedures & sequentials steps for shutting in a well:					
BOP system	✔		✔		✔
Surface/subsurface safety system					✔
Choke manifold	✔		✔		
15. Well control exercises with a simulator suitable for modeling well completion/well workover.			✔		
16. Well control exercises with a simulator suitable for modeling drilling.	✔				
17. Instructions & simulator or test well experience on organizing & directing a well killing operation.	✔		✔		
18. At least two simulator practice problems (rotate the trainees & have teams of 3 or less members).	✔		✔		
19. Care, operation, & purpose [& installation (for supervisors)] of the well control equipment.	✔	✔	✔	✔	
20. Limitations of the equipment that may wear or be subjected to pressure.	✔		✔		✔
21. Instructions in well control equipment, including:					
Surface equipment	✔		✔		✔
Well completion/well workover, BOP & tree equipment.	✔		✔		✔
Downhole tools & tubulars	✔		✔		
Tubing hanger, back pressure valve (threaded/profile), landing nipples, lock mandrels for corresponding nipples & operational procedures for each, gas lift equipment & running & pulling tools operation.	✔				✔
Packers	✔		✔		
22. Instructions in special tools & systems, such as:					
Automatic shutdown systems (control points, activator pilots, monitor pilots, control manifolds & subsurface systems).					✔
Flow string systems (tubing, mandrels & nipples, flow couplings, blast joints, & sliding sleeves).					✔
Pumpdown equipment (purpose, applications, requirements, surface circulating systems, entry loops & tree connection/flange).					✔
23. Instructions for detecting entry into abnormally pressured formations & warning signals.	✔				
24. Instructions on well completion/well control problems	✔				
25. Well control problems during well completion/well workover including:					
Killing a flow			✔		
Simultaneous drilling, completion & workover operations on the same platform.			✔		
Killing a producing well			✔		
Removing the tree			✔		
26. Calculations on the following:					
Fluid density increase that controls fluid flow into the wellbore.	✔		✔		

TABLE (a).—WELL CONTROL—Continued

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
Fluid density to pressure conversion & the danger of formation breakdown under the pressure caused by the fluid column especially when setting casing in shallow formations.	✔				
Fluid density to pressure conversion & the danger of formation breakdown under the pressure caused by fluid column.			✔		
Equivalent pressures at the casing seat depth	✔				
Drop in pump pressure as fluid density increases; & the relationship between pump pressure, pump rate, & fluid density.	✔		✔		
Pressure limitations on casings	✔		✔		
Hydrostatic pressure & pressure gradient	✔		✔		
27. Unusual well control situations, including the following:					
Drill pipe is off the bottom or out of the hole/work string is off the bottom or out of the hole.	✔		✔		
Lost circulation occurs	✔		✔		
Drill pipe is plugged/work string is plugged	✔		✔		
There is excessive casing pressure	✔		✔		
There is a hole in drill pipe/hole in the work string/hole in the casing string.	✔		✔		
Multiple completions in the hole			✔		
28. Special well-control problems-drilling with a subsea stack (subsea students) includes:					
Choke line friction determinations	✔		✔		
Using marine risers	✔		✔		
Riser collapse	✔		✔		
Removing trapped gas from the BOP stack after controlling a well kick.	✔		✔		
"U" tube effect as gas hits the choke line	✔		✔		
29. Mechanics of various well controlled situations, including:					
Gas bubble migration & expansion	✔		✔		
Bleeding volume from a shut-in well during gas migration.	✔		✔		
Excessive annular surface pressure	✔		✔		
Differences between a gas kick & a salt water and/or oil kick.	✔		✔		
Special well control techniques (such as, but not limited to, barite plugs & cement plugs).	✔		✔		
Procedures & problems involved when experiencing lost circulation.	✔		✔		
Procedures & problems involved when experiencing a kick while drilling in a hydrogen sulfide (H_2S) environment.	✔		✔		✔
Procedures & problems—experiencing a kick during snubbing, coil-tubing, or small tubing operations and stripping & snubbing operations with work string.	✔		✔		
30. Reasons for well completion/well workover, including:					
Reworking a reservoir to control production			✔		✔
Water coning			✔		
Completing from a new reservoir			✔		✔
Completing multiple reservoirs			✔		✔
Stimulating to increase production			✔		✔
Repairing mechanical failure			✔		✔
31. Methods on preparing a well for entry:					
Using back pressure valves			✔		
Using surface & subsurface safety systems			✔		✔
Removing the tree & tubing hangar			✔	✔	✔
Installing & testing BOP & wellhead prior to removing back pressure valves & tubing plugs.			✔		✔
32. Instructions in small tubing units:					
Applications (stimulation operations, cleaning out tubing obstructions, and plugback and squeeze cementing).			✔		
Equipment description (derrick & drawworks, small tubing, pumps, weighted fluid facilities, and weighted fluids).			✔		

TABLE (a).—WELL CONTROL—Continued

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
BOP equipment (rams, wellhead connection, and check valve).			✔		
33. Methods for killing a producing well, including:					
Bullheading			✔		✔
Lubricating & bleeding			✔		✔
Coil tubing			✔		✔
Applications (stimulation operations, initiating flow, & cleaning out sand in tubing).					✔
Equipment description (coil tubing, reel, injecting head, control assembly & injector hoist).					✔
BOP equipment (tree connection or flange, rams, injector assembly & circulating system).					✔
Snubbing			✔		✔
Types (rig assist & stand alone)					✔
Applications (running & pulling production or kill strings, resetting weight on packers, fishing for lost wireline tools or parted kill strings & circulating cement or fluid).					✔
Equipment (operating mechanism, power supply, control assembly & basket, slip assembly, mast & counterbalance winch & access window).					✔
BOP equipment (tree connection or flange, rams, spool, traveling slips, manifolds, auxiliary—full opening safety valve inside BOP, maintenance & testing).					✔
34. The purpose & use of BOP closing units, including the following:					
Charging procedures include precharge & operating pressure.	✔		✔		
Fluid volumes (useable & required)	✔		✔		
Fluid pumps	✔		✔		
Maintenance that includes charging fluid & inspection procedures.	✔		✔		
35. Instructions on stripping & snubbing operators & using the BOP system for working pipe in or out of a wellbore under pressure.	✔				

TABLE (b)—PRODUCTION SAFETY SYSTEMS

1. Government Regulations:
   - Pollution prevention & waste management
   - Requirements for well completion/well workover operations
2. Instructions in the following: (contained in, but not limited to, API RP 14C):
   - Failures or malfunctions in systems that cause abnormal conditions & the detection of abnormal conditions
   - Primary & secondary protection devices & procedures
   - Safety devices that control undesirable events
   - Safety analysis concepts
   - Safety analysis of each basic production process component
   - Protection concepts
3. Hands on training on safety devices covering, installing, operating, repairing or maintaining equipment:
   - High-low pressure sensors
   - High-low level sensors
   - Combustible gas detectors
   - Pressure relief devices
   - Flow line check valves
   - Surface safety valves
   - Shutdown valves
   - Fire (flame, heat, or smoke) detectors
   - Auxiliary devices (3-way block & bleed valves, time relays, 3-way snap acting valves, etc.)
   - Surface-controlled subsurface safety valves &/or surface-control equipment
   - Subsurface-controlled subsurface safety valves
4. Instructions on inspecting, testing & maintaining surface & subsurface devices & surface control systems for subsurface safety valves
5. Instructions in at least one safety device that illustrates the primary operation principle in each class for safety devices:

TABLE (b)—PRODUCTION SAFETY SYSTEMS—Continued

Basic operations principles
Limits affecting application
Problems causing equipment malfunction & how to correct these problems
A test for proper actuation point & operation
Adjustments or calibrations
Recording inspection results & malfunctions
Special techniques for installing safety devices
6. Instructions on the basic principle & logic of the emergency support system:
Combustible & toxic gas detection system
Liquid containment system
Fire loop System
Other fire detection systems
Emergency shutdown system
Subsurface safety valves

[62 FR 5326, Feb. 5, 1997, as amended at 62 FR 7298, Feb. 18, 1997]

§ 250.230 If MMS tests employees at my worksite, what must I do?

(a) You must allow MMS to test employees at your worksite.

(b) You must identify your employees by:

(1) Current job classification;

(2) Name of the operator;

(3) Name of the most recent basic or advanced course taken by your employees for their current job; and

(4) Name of the training organization.

(c) You must correct any deficiencies found by MMS. Steps for correcting deficiencies may include:

(1) Isolating problems by doing more testing; and

(2) Reassigning employees or conducting training (MMS will not identify the employees it tests).

§ 250.231 If MMS test trainees at a training organization's facility, what must occur?

(a) Training organizations must allow MMS to test trainees.

(b) The trainee must pass the MMS-conducted test or a retest in order for MMS to consider that the trainee completed the training.

§ 250.232 Why might MMS conduct its own tests?

MMS needs to identify the effectiveness of a training program that provides for safe and clean operations.

§ 250.233 Can a training organization lose its accreditation?

Yes, an accredited organization can lose its accreditation. MMS may revoke or suspend an organization's accreditation for noncompliance with regulations or conditions of its accredited program, or assess civil penalties under subpart N of this part.

Subpart P—Sulphur Operations

SOURCE: 56 FR 32100, July 15, 1991, unless otherwise noted.

§ 250.250 Performance standard.

Operations to discover, develop, and produce sulphur in the OCS shall be in accordance with an approved Exploration Plan or Development and Production Plan and shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS including any mineral deposits (in areas leased or not leased), the national security or defense, and the marine, coastal, or human environment.

§ 250.251 Definitions.

Terms used in this subpart shall have the meanings as defined below:

Air line means a tubing string that is used to inject air within a sulphur producing well to airlift sulphur out of the well.

Bleedwater means a mixture of mine water or booster water and connate water that is produced by a bleedwell.

Bleedwell means a well drilled into a producing sulphur deposit that is used to control the mine pressure generated by the injection of mine water.

Brine means the water containing dissolved salt obtained from a brine well by circulating water into and out of a cavity in the salt core of a salt dome.

Brine well means a well drilled through cap rock into the core at a salt dome for the purpose of producing brine.

Cap rock means the rock formation, a body of limestone, anhydride, and/or gypsum, overlying a salt dome.

Sulphur deposit means a formation of rock that contains elemental sulphur.

Sulphur production rate means the number of long tons of sulphur produced during a certain period of time, usually per day.

§ 250.252 Applicability.

(a) The requirements of this subpart P are applicable to all exploration, development, and production operations under an OCS sulphur lease. Sulphur operations include all activities conducted under a lease for the purpose of discovery or delineation of a sulphur deposit and for the development and production of elemental sulphur. Sulphur operations also include activities conducted for related purposes. Activities conducted for related purposes include, but are not limited to, production of other minerals, such as salt, for use in the exploration for or the development and production of sulphur. The lessee must have obtained the right to produce and/or use these other minerals.

(b) Lessees conducting sulphur operations in the OCS shall comply with the requirements of the applicable provisions of subparts A, B, C, G, I, J, M, N, and O of this part.

(c) Lessees conducting sulphur operations in the OCS are also required to comply with the requirements in the applicable provisions of subparts D, E, F, H, K, and L of this part where such provisions specifically are referenced in this subpart.

§ 250.253 Determination of sulphur deposit.

(a) Upon receipt of a written request from the lessee, the District Supervisor will determine whether a sulphur deposit has been defined that contains sulphur in paying quantities (i.e., sulphur in quantities sufficient to yield a return in excess of the costs, after completion of the wells, of producing minerals at the wellheads).

(b) A determination under paragraph (a) of this section shall be based upon the following:

(1) Core analyses that indicate the presence of a producible sulphur deposit (including an assay of elemental sulphur);

(2) An estimate of the amount of recoverable sulphur in long tons over a specified period of time; and

(3) Contour map of the cap rock together with isopach map showing the extent and estimated thickness of the sulphur deposit.

§ 250.254 General requirements.

Sulphur lessees shall comply with requirements of this section when conducting well-drilling, well-completion, well-workover, or production operations.

(a) *Equipment movement.* The movement of well-drilling, well-completion, or well-workover rigs and related equipment on and off an offshore platform, or from one well to another well on the same offshore platform, including rigging up and rigging down, shall be conducted in a safe manner.

(b) *Hydrogen sulfide (H_2S).* When a drilling, well-completion, well-workover, or production operation is being conducted on a well in zones known to contain H_2S or in zones where the presence of H_2S is unknown (as defined in 30 CFR 250.67 of this part), the lessee shall take appropriate precautions to protect life and property, especially during operations such as dismantling wellhead equipment and flow lines and circulating the well. The lessee shall also take appropriate precautions when H_2S is generated as a result of sulphur production operations. The lessee shall comply with the requirements in § 250.67 of this part as

well as the requirements of this subpart.

(c) *Welding and burning practices and procedures.* All welding, burning, and hot-tapping activities involved in drilling, well-completion, well-workover or production operations shall be conducted with properly maintained equipment, trained personnel, and appropriate procedures in order to minimize the danger to life and property according to the specific requirements in § 250.52 of this part.

(d) *Electrical requirements.* All electrical equipment and systems involved in drilling, well-completion, well-workover, and production operations shall be designed, installed, equipped, protected, operated, and maintained so as to minimize the danger to life and property in accordance with the requirements of § 250.53 of this part.

(e) *Structures on fixed OCS platforms.* Derricks, cranes, masts, substructures, and related equipment shall be selected, designed, installed, used, and maintained so as to be adequate for the potential loads and conditions of loading that may be encountered during the operations. Prior to moving equipment such as a well-drilling, well-completion, or well-workover rig or associated equipment or production equipment onto a platform, the lessee shall determine the structural capability of the platform to safely support the equipment and operations, taking into consideration corrosion protection, platform age, and previous stresses.

(f) *Traveling-block safety device.* After August 14, 1992, all drilling units being used for drilling, well-completion, or well-workover operations that have both a traveling block and a crown block shall be equipped with a safety device that is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.260 Drilling requirements.

(a) Lessees of OCS sulphur leases shall conduct drilling operations in accordance with §§ 250.260 through 250.274 of this subpart and with other requirements of this part, as appropriate.

(b) *Fitness of drilling unit.* (1) Drilling units shall be capable of withstanding the oceanographic and meteorological conditions for the proposed season and location of operations.

(2) Prior to commencing operation, drilling units shall be made available for a complete inspection by the District Supervisor.

(3) The lessee shall provide information and data on the fitness of the drilling unit to perform the proposed drilling operation. The information shall be submitted with, or prior to, the submission of Form MMS–123, Application for Permit to Drill (APD), in accordance with § 250.272 of this subpart. After a drilling unit has been approved by an MMS district office, the information required in this paragraph need not be resubmitted unless required by the District Supervisor or there are changes in the equipment that affect the rated capacity of the unit.

(c) *Oceanographic, meteorological, and drilling unit performance data.* Where oceanographic, meteorological, and drilling unit performance data are not otherwise readily available, lessees shall collect and report such data upon request to the District Supervisor. The type of information to be collected and reported will be determined by the District Supervisor in the interests of safety in the conduct of operations and the structural integrity of the drilling unit.

(d) *Foundation requirements.* When the lessee fails to provide sufficient information pursuant to §§ 250.33 and 250.34 of this part to support a determination that the seafloor is capable of supporting a specific bottom-founded drilling unit under the site-specific soil and oceanographic conditions, the District Supervisor may require that additional surveys and soil borings be performed and the results submitted for review and evaluation by the District Supervisor before approval is granted for commencing drilling operations.

(e) *Tests, surveys, and samples.* (1) Lessees shall drill and take cores and/or run well and mud logs through the objective interval to determine the presence, quality, and quantity of sulphur

and other minerals (e.g., oil and gas) in the cap rock and the outline of the commercial sulphur deposit.

(2) Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 1,000 feet during the normal course of drilling. Directional surveys giving both inclination and azimuth shall be obtained on all directionally drilled wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 200 feet in all planned angle-change portions of the borehole.

(3) Directional surveys giving both inclination and azimuth shall be obtained on both vertically and directionally drilled wells at intervals not exceeding 500 feet prior to or upon setting a string of casing, or production liner, and at total depth. Composite directional surveys shall be prepared with the interval shown from the bottom of the conductor casing. In calculating all surveys, a correction from the true north to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north shall be made after making the magnetic-to-true-north correction. A composite dipmeter directional survey or a composite measurement while-drilling directional survey will be acceptable as fulfilling the applicable requirements of this paragraph.

(4) Wells are classified as vertical if the calculated average of inclination readings weighted by the respective interval lengths between readings from surface to drilled depth does not exceed 3 degrees from the vertical. When the calculated average inclination readings weighted by the length of the respective interval between readings from the surface to drilled depth exceeds 3 degrees, the well is classified as directional.

(5) At the request of a holder of an adjoining lease, the Regional Supervisor may, for the protection of correlative rights, furnish a copy of the directional survey to that leaseholder.

(f) *Fixed drilling platforms.* Applications for installation of fixed drilling platforms or structures including artificial islands shall be submitted in accordance with the provisions of subpart I, Platforms and Structures, of this part. Mobile drilling units that have their jacking equipment removed or have been otherwise immobilized are classified as fixed bottom founded drilling platforms.

(g) *Crane operations.* Cranes installed on fixed bottom-founded platforms shall be operated and maintained in accordance with the provisions of American Petroleum Institute (API) Recommended Practice (RP) for Operation and Maintenance of Offshore Cranes (API RP 2D) to ensure the safety of facility operations. Records of inspection, testing, maintenance, and crane operator qualifications in accordance with the provisions of API RP 2D shall be kept by the lessee at the lessee's field office nearest the OCS facility for a period of 2 years.

(h) *Diesel-engine air intakes.* After August 14, 1992, diesel-engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended shall be equipped with either remote-operated manual or automatic-shutdown devices. Diesel engines that are not continuously attended shall be equipped with automatic shutdown devices.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.261 Control of wells.

The lessee shall take necessary precautions to keep its wells under control at all times. Operations shall be conducted in a safe and workmanlike manner. The lessee shall utilize the best available and safest drilling technologies and state-of-the-art methods to evaluate and minimize the potential for a well to flow or kick. The lessee shall utilize personnel who are trained and competent and shall utilize and maintain equipment and materials necessary to assure the safety and protection of personnel, equipment, natural resources, and the environment.

§ 250.262 Field rules.

When geological and engineering information in a field enables a District Supervisor to determine specific operating requirements, field rules may be established for drilling, well completion, or well workover on the District Supervisor's initiative or in response to a request from a lessee; such rules may modify the specific requirements

of this subpart. After field rules have been established, operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field rules may be amended or canceled for cause at any time upon the initiative of the District Supervisor or upon the request of a lessee.

§ 250.263 Well casing and cementing.

(a) *General requirements.* (1) For the purpose of this subpart, the several casing strings in order of normal installation are:

(i) Drive or structural,

(ii) Conductor,

(iii) Cap rock casing,

(iv) Bobtail cap rock casing (required when the cap rock casing does not penetrate into the cap rock),

(v) Second cap rock casing (brine wells), and

(vi) Production liner.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing cemented in a manner necessary to prevent release of fluids from any stratum through the wellbore (directly or indirectly) into the sea, protect freshwater aquifers from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids. Cement composition, placement techniques, and waiting time shall be designed and conducted so that the cement in place behind the bottom 500 feet of casing or total length of annular cement fill, if less, attains a minimum compressive strength of 160 pounds per square inch (psi).

(3) The lessee shall install casing designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof. Safety factors in the drilling and casing program designs shall be of sufficient magnitude to provide well control during drilling and to assure safe operations for the life of the well.

(4) In cases where cement has filled the annular space back to the mud line, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment if the District Supervisor determines that subsurface protection against damage to freshwater aquifers and against damage caused by adverse loads, pressures, and fluid flows is not jeopardized.

(5) If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe. If the test indicates inadequate cementing, the lessee shall initiate remedial action as approved by the District Supervisor. For cap rock casing, the test for adequacy of cementing shall be the pressure testing of the annulus between the cap rock and the conductor casings. The pressure shall not exceed 70 percent of the burst pressure of the conductor casing or 70 percent of the collapse pressure of the cap rock casing.

(b) *Drive or structural casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth of 100 feet below the mud line or such other depth, as may be required or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, a quantity of cement sufficient to fill the annular space back to the mud line shall be used.

(c) *Conductor and cap rock casing setting and cementing requirements.* (1) Conductor and cap rock casing design and setting depths shall be based upon relevant engineering and geologic factors including the presence or absence of hydrocarbons, potential hazards, and water depths. The proposed casing setting depths may be varied, subject to District Supervisor approval, to permit the casing to be set in a competent formation or through formations determined desirable to be isolated from the wellbore by casing for safer drilling operations. However, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas or, if unknown, upon encountering such formations. Cap rock casing shall be set and cemented through formations known to contain

oil or gas or, if unknown, upon encountering such formations. Upon encountering unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval.

(2) Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line. Cement fill shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible, additional quantities of cement shall be used to assure fill to the mud line.

(3) Cap rock casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near surface fractures and faulting exist, cap rock casing shall be cemented with a quantity of cement that fills the calculated annular space to the mud line, unless otherwise approved by the District Supervisor. In brine wells, the second cap rock casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet above the setting depth of the first cap rock casing.

(d) *Bobtail cap rock casing setting and cementing requirements.* (1) Bobtail cap rock casing shall be set on or just in cap rock and lapped a minimum of 100 feet into the previous casing string.

(2) Sufficient cement shall be used to fill the annular space to the top of the bobtail cap rock casing.

(e) *Production liner setting and cementing requirements.* (1) Production liners for sulphur wells and bleedwells shall be set in cap rock at or above the bottom of the open hole (hole that is open in cap rock, below the bottom of the cap rock casing) and lapped into the previous casing string or to the surface. For brine wells, the liner shall be set in salt and lapped into the previous casing string or to the surface.

(2) The production liner is not required to be cemented unless the cap rock contains oil or gas. If the cap rock contains oil or gas, sufficient cement shall be used to fill the annular space to the top of the production liner.

§ 250.264 Pressure testing of casing.

(a) Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested. The conductor casing shall be tested to at least 200 psi. All casing strings below the conductor casing shall be tested to 500 psi or 0.22 psi/ft, whichever is greater. (When oil or gas is not present in the cap rock, the production liner need not be cemented in place; thus, it would not be subject to pressure testing.) If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing tested again. The above procedures shall be repeated until a satisfactory test is obtained. The time, conditions of testing, and results of all casing pressure tests shall be recorded in the driller's report.

(b) After cementing any string of casing other than structural, drilling shall not be resumed until there has been a timelapse of at least 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§ 250.265 Blowout preventer systems and system components.

(a) *General.* The blowout preventer (BOP) systems and system components shall be designed, installed, used, maintained, and tested to assure well control.

(b) *BOP stacks.* The BOP stacks shall consist of an annular preventer and the number of ram-type preventers as specified under paragraphs (e) and (f) of this section. The pipe rams shall be of proper size to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP shall exceed the surface pressure to which it may be anticipated to be subjected.

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system that provides sufficient capacity to supply 1.5 times the volume necessary to close and hold closed all BOP equipment

units with a minimum pressure of 200 psi above the precharge pressure, without assistance from a charging system. After February 14, 1992, accumulator regulators supplied by rig air, which do not have a secondary source of pneumatic supply, shall be equipped with manual overrides or other devices alternately provided to ensure capability of hydraulic operations if rig air is lost.

(2) An automatic backup to the accumulator system. The backup system shall be supplied by a power source independent from the power source to the primary accumulator system. The automatic backup system shall possess sufficient capability to close the BOP and hold it closed.

(3) At least one operable remote BOP control station in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

(4) A drilling spool with side outlets, if side outlets are not provided in the body of the BOP stack, to provide for separate kill and choke lines.

(5) A choke line and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line and one valve on the kill line shall be remotely controlled, except that a check valve may be installed on the kill line in lieu of the remotely controlled valve, provided that two readily accessible manual valves are in place and the check valve is placed between the manual valve and the pump.

(6) A fill-up line above the uppermost preventer.

(7) A choke manifold designed with consideration of anticipated pressures to which it may be subjected, method of well control to be employed, surrounding environment, and corrosiveness, volume, and abrasiveness of fluids. The choke manifold shall also meet the following requirements:

(i) Manifold and choke equipment subject to well and/or pump pressure shall have a rated working pressure at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor;

(ii) All components of the choke manifold system shall be protected from freezing by heating, draining, or filling with proper fluids; and

(iii) When buffer tanks are installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together, isolation valves shall be installed on each line.

(8) Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold with a pressure rating at least as great as the rated working pressure of the ram-type BOP's unless otherwise approved by the District Supervisor.

(9) A wellhead assembly with a rated working pressure that exceeds the pressure to which it might be subjected.

(10) The following system components:

(i) A kelly cock (an essentially full-opening valve) installed below the swivel and a similar valve of such design that it can be run through the BOP stack installed at the bottom of the kelly. A wrench to fit each valve shall be stored in a location readily accessible to the drilling crew;

(ii) An inside BOP and an essentially full-opening, drill-string safety valve in the open position on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew;

(iii) A safety valve available on the rig floor assembled with the proper connection to fit the casing string being run in the hole; and

(iv) Locking devices installed on the ram-type preventers.

(e) *BOP requirements.* Prior to drilling below cap rock casing, a BOP system shall be installed consisting of at least three remote-controlled, hydraulically operated BOP's including at least one equipped with pipe rams, one with blind rams, and one annular type.

(f) *Tapered drill-string operations.* Prior to commencing tapered drill-string operations, the BOP stack shall be equipped with conventional and/or variable-bore pipe rams to provide either of the following:

(1) One set of variable bore rams capable of sealing around both sizes in the string and one set of blind rams, or

(2) One set of pipe rams capable of sealing around the larger size string, provided that blind-shear ram capability is present, and crossover subs to the larger size pipe are readily available on the rig floor.

§ 250.266 Blowout preventer systems tests, actuations, inspections, and maintenance.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a pressure of 200 to 300 psi.

(b) Ram-type BOP's and the choke manifold shall be pressure tested with water to rated working pressure or as otherwise approved by the District Supervisor. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Supervisor.

(c) In conjunction with the weekly pressure test of BOP systems required in paragraph (d) of this section, the choke manifold valves, upper and lower kelly cocks, and drill-string safety valves shall be pressure tested to pipe-ram test pressures. Safety valves with proper casing connections shall be actuated prior to running casing.

(d) BOP system shall be pressure tested as follows:

(1) When installed;

(2) Before drilling out each string of casing or before continuing operations in cases where cement is not drilled out;

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. If either control system is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between BOP tests is allowed when there is a stuck drill pipe or there are pressure control operations and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operations resume. The date, time, and reason for postponing pressure testing shall be entered into the driller's report. Pressure testing shall be performed at intervals to allow each drilling crew to operate the equipment. The weekly pressure test is not required for blind and blind-shear rams;

(4) Bind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than necessary to indicate proper operation of the rams is not required;

(5) Variable bore-pipe rams shall be pressure tested against all sizes of pipe in use, excluding drill collars and bottomhole tools; and

(6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly. In this situation, the pressure tests may be limited to the affected component.

(e) All BOP systems shall be inspected and maintained to assure that the equipment will function properly. The BOP systems shall be visually inspected at least once each day. The manufacturer's recommended inspection and maintenance procedures are acceptable as guidelines in complying with this requirement.

(f) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test duration for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(g) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system and system components shall be recorded in the driller's report. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the driller's report may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the driller's report.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to

remedy such problems or irregularities shall be noted in the driller's report.

(4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections, shall be available for MMS review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all drilling records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

§ 250.267 Well-control drills.

Well-control drills shall be conducted for each drilling crew in accordance with the requirements set forth in § 250.58 of this part or as approved by the District Supervisor.

§ 250.268 Diverter systems.

(a) When drilling a conductor or cap rock hole, all drilling units shall be equipped with a diverter system consisting of a diverter sealing element, diverter lines, and control systems. The diverter system shall be designed, installed, and maintained so as to divert gases, water, mud, and other materials away from the facilities and personnel.

(b) After August 14, 1992, diverter systems shall be in compliance with the requirements of this section.

The requirements applicable to diverters that were in effect immediately prior to August 14, 1991, shall remain in effect until August 14, 1992.

(c) The diverter system shall be equipped with remote-control valves in the flow lines that can be operated from at least one remote-control station in addition to the one on the drilling floor. Any valve used in a diverter system shall be full opening. No manual or butterfly valves shall be installed in any part of a diverter system. There shall be a minimum number of turns in the vent line(s) downstream of the spool outlet flange, and the radius of curvature of turns shall be as large as practicable. Flexible hose may be used for diversion lines instead of rigid pipe if the flexible hose has integral end couplings. The entire diverter system shall be firmly anchored and supported to prevent whipping and vibrations. All diverter control equipment and lines shall be protected from physical damage from thrown and falling objects.

(d) For drilling operations conducted with a surface wellhead configuration, the following shall apply:

(1) If the diverter system utilizes only one spool outlet, branch lines shall be installed to provide downwind diversion capability, and

(2) No spool outlet or diverter line internal diameter shall be less than 10 inches, except that dual spool outlets are acceptable if each outlet has a minimum internal diameter of 8 inches, and both outlets are piped to overboard lines and that each line downstream of the changeover nipple at the spool has a minimum internal diameter of 10 inches.

(e) The diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psi when nippled upon conductor casing. No more than 7 days shall elapse between subsequent pressure tests. The diverter sealing element, diverter valves, and diverter control systems (including the remote) shall be actuation tested, and the diverter lines shall be tested for flow prior to spudding and thereafter at least once each 24-hour period alternating between control stations. All test times and results shall be recorded in the driller's report.

§ 250.269 Mud program.

(a) The quantities, characteristics, use, and testing of drilling mud and the related drilling procedures shall be designed and implemented to prevent the loss of well control.

(b) The lessee shall comply with requirements concerning mud control, mud test and monitoring equipment, mud quantities, and safety precautions in enclosed mud handling areas as prescribed in § 250.60 (b), (c), (d), and (e) of this part, except that the installation of an operable degasser in the mud system as required in § 250.60(b)(8) is not required for sulphur operations.

§ 250.270 Securing of wells.

A downhole-safety device such as a cement plug, bridge plug, or packer shall be timely installed when drilling operations are interrupted by events such as those that force evacuation of the drilling crew, prevent station keeping, or require repairs to major drilling units or well-control equipment. The use of blind-shear rams or pipe rams and an inside BOP may be approved by the District Supervisor in lieu of the above requirements if cap rock casing has been set.

§ 250.271 Supervision, surveillance, and training.

(a) The lessee shall provide onsite supervision of drilling operations at all times.

(b) From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with BOP's, bridge plugs, packers, or cement plugs.

(c) Lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of subpart O of this part. Records of specific training that lessee and drilling contractor personnel have successfully completed, the dates of completion, and the names and dates of the courses shall be maintained at the drill site.

§ 250.272 Application for permit to drill.

(a) Prior to commencing the drilling of a well under an approved Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, the lessee shall file Form MMS–123, APD, with the District Supervisor for approval. Prior to commencing operations, written approval from the District Supervisor must be received by the lessee unless oral approval has been given pursuant to § 250.6(a) of this part.

(b) An APD shall include rated capacities of the proposed drilling unit and of major drilling equipment. After a drilling unit has been approved for use in an MMS district, the information need not be resubmitted unless required by the District Supervisor or there are changes in the equipment that affect the rated capacity of the unit.

(c) An APD shall include a fully completed Form MMS–123 and the following:

(1) A plat, drawn to a scale of 2,000 feet to the inch, showing the surface and subsurface location of the well to be drilled and of all the wells previously drilled in the vicinity from which information is available. For development wells on a lease, the wells previously drilled in the vicinity need not be shown on the plat. Locations shall be indicated in feet from the nearest block line;

(2) The design criteria considered for the well and for well control, including the following:

(i) Pore pressure;

(ii) Formation fracture gradients;

(iii) Potential lost circulation zones;

(iv) Mud weights;

(v) Casing setting depths;

(vi) Anticipated surface pressures (which for purposes of this section are defined as the pressure that can reasonably be expected to be exerted upon a casing string and its related wellhead equipment). In the calculation of anticipated surface pressure, the lessee shall take into account the drilling, completion, and producing conditions. The lessee shall consider mud densities to be used below various casing strings, fracture gradients of the exposed formations, casing setting depths, and cementing intervals, total well depth, formation fluid type, and other pertinent conditions. Considerations for calculating anticipated surface pressure may vary for each segment of the well. The lessee shall include as a part of the statement of anticipated surface pressure the calculations used to determine this pressure during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design; and

(vii) If a shallow hazards site survey is conducted, the lessee shall submit with or prior to the submittal of the APD, two copies of a summary report describing the geological and manmade conditions present. The lessee shall also submit two copies of the site maps and data records identified in the survey strategy.

(3) A BOP equipment program including the following:

(i) The pressure rating of BOP equipment,

(ii) A schematic drawing of the diverter system to be used (plan and elevation views) showing spool outlet internal diameter(s); diverter line lengths and diameters, burst strengths, and radius of curvature at each turn; valve type, size, working-pressure rating, and location; the control instrumentation logic; and the operating procedure to be used by personnel, and

(iii) A schematic drawing of the BOP stack showing the inside diameter of the BOP stack and the number of annular, pipe ram, variable-bore pipe ram, blind ram, and blind-shear ram preventers.

(4) A casing program including the following:

(i) Casing size, weight, grade, type of connection and setting depth, and

(ii) Casing design safety factors for tension, collapse, and burst with the assumptions made to arrive at these values.

(5) The drilling prognosis including the following:

(i) Estimated coring intervals,

(ii) Estimated depths to the top of significant marker formations, and

(iii) Estimated depths at which encounters with fresh water, sulphur, oil, gas, or abnormally pressured water are expected.

(6) A cementing program including type and amount of cement in cubic feet to be used for each casing string;

(7) A mud program including the minimum quantities of mud and mud materials, including weight materials, to be kept at the site;

(8) A directional survey program for directionally drilled wells;

(9) An H_2S Contingency Plan, if applicable, and if not previously submitted; and

(10) Such other information as may be required by the District Supervisor.

(d) Public information copies of the APD shall be submitted in accordance with § 250.17 of this part.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.273 Sundry notices and reports on wells.

(a) Notices of the lessee's intention to change plans, make changes in major drilling equipment, deepen, sidetrack, or plug back a well, or engage in similar activities and subsequent reports pertaining to such operations shall be submitted to the District Supervisor on Form MMS–124, Sundry Notices and Reports on Wells. Prior to commencing operations associated with the change, written approval must be received from the District Supervisor unless oral approval is obtained pursuant to § 250.6(a) of this part.

(b) The Form MMS–124 submittal shall contain a detailed statement of the proposed work that will materially change from the work described in the approved APD. Information submitted shall include the present state of the well, including the production liner and last string of casing, the well depth and production zone, and the well's capability to produce. Within 30 days after completion of the work, a subsequent detailed report of all the work done and the results obtained shall be submitted.

(c) Public information copies of Form MMS–124 shall be submitted in accordance with § 250.17 of this part.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.274 Well records.

(a) Complete and accurate records for each well and all well operations shall be retained for a period of 2 years at the lessee's field office nearest the OCS facility or at another location conveniently available to the District Supervisor. The records shall contain a description of any significant malfunction or problem; all the formations penetrated; the content and character of sulphur in each formation if cored and analyzed; the kind, weight, size, grade, and setting depth of casing; all well logs and surveys run in the wellbore; and all other information required by the District Supervisor in the interests of resource evaluation, prevention of waste, conservation of

natural resources, protection of correlative rights, safety of operations, and environmental protection.

(b) When drilling operations are suspended or temporarily prohibited under the provisions of § 250.10 of this part, the lessee shall, within 30 days after termination of the suspension or temporary prohibition or within 30 days after the completion of any activities related to the suspension or prohibition, transmit to the District Supervisor duplicate copies of the records of all activities related to and conducted during the suspension or temporary prohibition on, or attached to, Form MMS–125, Well Summary Report, or Form MMS–124, Sundry Notices and Reports on Wells, as appropriate.

(c) Upon request by the Regional or District Supervisor, the lessee shall furnish the following:

(1) Copies of the records of any of the well operations specified in paragraph (a) of this section;

(2) Copies of the driller's report at a frequency as determined by the District Supervisor. Items to be reported include spud dates, casing setting depths, cement quantities, casing characteristics, mud weights, lost returns, and any unusual activities; and

(3) Legible, exact copies of reports on cementing, acidizing, analyses of cores, testing, or other similar services.

(d) As soon as available, the lessee shall transmit copies of logs and charts developed by well-logging operations, directional-well surveys, and core analyses. Composite logs of multiple runs and directional-well surveys shall be transmitted to the District Supervisor in duplicate as soon as available but not later than 30 days after completion of such operations for each well.

(e) If the District Supervisor determines that circumstances warrant, the lessee shall submit any other reports and records of operations in the manner and form prescribed by the District Supervisor.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.280 Well-completion and well-workover requirements.

(a) Lessees shall conduct well-completion and well-workover operations in sulphur wells, bleedwells, and brine wells in accordance with §§ 250.280 through 250.286 of this part and other provisions of this part as appropriate (see §§ 250.71 and 250.91 of this part for the definition of well-completion and well-workover operations).

(b) Well-completion and well-workover operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment.

§ 250.281 Crew instructions.

Prior to engaging in well-completion or well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available for MMS review.

§ 250.282 Approvals and reporting of well-completion and well-workover operations.

(a) No well-completion or well-workover operation shall begin until the lessee receives written approval from the District Supervisor. Approval for such operations shall be requested on Form MMS–124. Approvals by the District Supervisor shall be based upon a determination that the operations will be conducted in a manner to protect against harm or damage to life, property, natural resources of the OCS, including any mineral deposits, the national security or defense, or the marine, coastal, or human environment.

(b) The following information shall be submitted with Form MMS–124 (or with Form MMS–123):

(1) A brief description of the well-completion or well-workover procedures to be followed;

(2) When changes in existing subsurface equipment are proposed, a schematic drawing showing the well equipment; and

(3) Where the well is in zones known to contain H_2S or zones where the presence of H_2S is unknown, a description

of the safety precautions to be implemented.

(c)(1) Within 30 days after completion, Form MMS–125, including a schematic of the tubing and the results of any well tests, shall be submitted to the District Supervisor.

(2) Within 30 days after completing the well-workover operation, except routine operations, Form MMS–124 shall be submitted to the District Supervisor and shall include the results of any well tests and a new schematic of the well if any subsurface equipment has been changed.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993]

§ 250.283 Well-control fluids, equipment, and operations.

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be ccntinuously monitored during well-completion and well-workover operations and shall not be left unattended at any time unless the well is shut in and secured;

(b) The following well-control fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP,

(2) A well-control fluid-volume measuring device for determining fluid volumes when filling the hole on trips, and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

(c) When coming out of the hole with drill pipe or a workover string, the annulus shall be filled with well-control fluid before the change in fluid level decreases the hydrostatic pressure 75 psi or every five stands of drill pipe or workover string, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe or workover string and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.

§ 250.284 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure of the BOP system and system components shall equal or exceed the expected surface pressure to which they may be subjected.

(b) The minimum BOP stack for well-completion operations or for well-workover operations with the tree removed shall consist of the following:

(1) Three remote-controlled, hydraulically operated preventers including at least one equipped with pipe rams, one with blind rams, and one annular type.

(2) When a tapered string is used, the minimum BOP stack shall consist of either of the following:

(i) An annular preventer, one set of variable bore rams capable of sealing around both sizes in the string, and one set of blind rams; or

(ii) An annular preventer, one set of pipe rams capable of sealing around the larger size string, a preventer equipped with blind-shear rams, and a crossover sub to the larger size pipe that shall be readily available on the rig floor.

(c) The BOP systems for well-completion operations, or for well-workover operations with the tree removed, shall be equipped with the following:

(1) An accumulator system that provides sufficient capacity to supply 1.5 times the volume necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. After February 14, 1992, accumulator regulators supplied by rig air which do not have a secondary source of pneumatic supply shall be equipped with manual overrides or alternately other devices provided to ensure capability of hydraulic operations if rig air is lost;

(2) An automatic backup to the accumulator system supplied by a power source independent from the power source to the primary accumulator system and possessing sufficient capacity to close all BOP's and hold them closed;

(3) Locking devices for the pipe-ram preventers;

(4) At least one remote BOP-control station and one BOP-control station on the rig floor; and

(5) A choke line and a kill line each equipped with two full-opening valves and a choke manifold. One of the choke-line valves and one of the kill-line valves shall be remotely controlled except that a check valve may be installed on the kill line in lieu of the remotely-controlled valve provided that two readily accessible manual valves are in place, and the check valve is placed between the manual valve and the pump.

(d) The minimum BOP-stack components for well-workover operations with the tree in place and performed through the wellhead inside of the sulphur line using small diameter jointed pipe (usually ¾ inch to 1¼ inch) as a work string; i.e., small-tubing operations, shall consist of the following:

(1) For air line changes, the well shall be killed prior to beginning operations. The procedures for killing the well shall be included in the description of well-workover procedures in accordance with § 250.282 of this part. Under these circumstances, no BOP equipment is required.

(2) For other work inside of the sulphur line, a tubing stripper or annular preventer shall be installed prior to beginning work.

(e) An essentially full-opening, work-string safety valve shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting a safety valve in the work string.

§ 250.285 Blowout preventer system testing, records, and drills.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a pressure of 200 to 300 psi.

(b) Ram-type BOP's and the choke manifold shall be pressure tested with water to a rated working pressure or as otherwise approved by the District Supervisor. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Supervisor.

(c) In conjunction with the weekly pressure test of BOP systems required in paragraph (d) of this section, the choke manifold valves, upper and lower kelly cocks, and drill-string safety valves shall be pressure tested to pipe-ram test pressures. Safety valves with proper casing connections shall be actuated prior to running casing.

(d) BOP system shall be pressure tested as follows:

(1) When installed;

(2) Before drilling out each string of casing or before continuing operations in cases where cement is not drilled out;

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. If either control system is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between BOP tests is allowed when there is a stuck drill pipe or there are pressure control operations, and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operations resume. The time, date, and reason for postponing pressure testing shall be entered into the driller's report. Pressure testing shall be performed at intervals to allow each drilling crew to operate the equipment. The weekly pressure test is not required for blind and blind-shear rams;

(4) Blind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than necessary to indicate proper operation of the rams is not required;

(5) Variable bore-pipe rams shall be pressure tested against all sizes of pipe in use, excluding drill collars and bottomhole tools; and

(6) Following the disconnection or repair of any well-pressure containment

seal in the wellhead/BOP stack assembly, the pressure tests may be limited to the affected component.

(e) All personnel engaged in well-completion operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(f) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test duration for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(g) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system and system components shall be recorded in the operations log. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the operations log.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the operations log.

(4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections shall be available for MMS review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all drilling records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

§ 250.286 Tubing and wellhead equipment.

(a) No tubing string shall be placed into service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) Wellhead, tree, and related equipment shall be designed, installed, tested, used, and maintained so as to achieve and maintain pressure control.

§ 250.290 Production requirements.

(a) The lessee shall conduct sulphur production operations in compliance with the approved Development and Production Plan requirements of §§ 250.290 through 250.297 of this subpart and requirements of this part, as appropriate.

(b) Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety of operations and protection of the human, marine, and coastal environments.

§ 250.291 Design, installation, and operation of production systems.

(a) *General.* All production facilities shall be designed, installed, and maintained in a manner that provides for efficiency and safety of operations and protection of the environment.

(b) *Approval of design and installation features for sulphur production facilities.* Prior to installation, the lessee shall submit a sulphur production system application, in duplicate, to the District Supervisor for approval. The application shall include information relative to the proposed design and installation features. Information concerning approved design and installation features shall be maintained by the lessee at the lessee's offshore field office nearest the OCS facility or at another location conveniently available to the District Supervisor. All approvals are subject to field verification. The application shall include the following:

(1) A schematic flow diagram showing size, capacity, design, working pressure of separators, storage tanks, compressor pumps, metering devices, and other sulphur-handling vessels;

(2) A schematic piping diagram showing the size and maximum allowable

working pressures as determined in accordance with API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems;

(3) Electrical system information including a plan of each platform deck, outlining all hazardous areas classified in accordance with API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, and outlining areas in which potential ignition sources are to be installed;

(4) Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the new installations conform to the approved designs of this subpart.

(c) *Hydrocarbon handling vessels associated with fuel gas system.* Hydrocarbon handling vessels associated with the fuel gas system shall be protected with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms (API RP 14C). If processing components are to be utilized, other than those for which Safety Analysis Checklists are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system.

(d) *Approval of safety-systems design and installation features for fuel gas system.* Prior to installation, the lessee shall submit a fuel gas safety system application, in duplicate, to the District Supervisor for approval. The application shall include information relative to the proposed design and installation features. Information concerning approved design and installation features shall be maintained by the lessee at the lessee's offshore field office nearest the OCS facility or at another location conveniently available to the District Supervisor. All approvals are subject to field verification. The application shall include the following:

(1) A schematic flow diagram showing size, capacity, design, working pressure of separators, storage tanks, compressor pumps, metering devices, and other hydrocarbon-handling vessels;

(2) A schematic flow diagram (API RP 14C, Figure E1) and the related Safety Analysis Function Evaluation chart (API RP 14C, subsection 4.3c);

(3) A schematic piping diagram showing the size and maximum allowable working pressures as determined in accordance with API RP 14E, Design and Installation of Offshore Production Platform Piping Systems;

(4) Electrical system information including the following:

(i) A plan of each platform deck, outlining all hazardous areas classified in accordance with API RP 500 and outlining areas in which potential ignition sources are to be installed;

(ii) All significant hydrocarbon sources and a description of the type of decking, ceiling, walls (e.g., grating or solid), and firewalls; and

(iii) Elementary electrical schematic of any platform safety shutdown system with a functional legend.

(5) Certification that the design for the mechanical and electrical systems to be installed was approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the new installations conform to the approved designs of this subpart; and

(6) Design and schematics of the installation and maintenance of all fire- and gas-detection systems including the following:

(i) Type, location, and number of detection heads;

(ii) Type and kind of alarm, including emergency equipment to be activated;

(iii) Method used for detection;

(iv) Method and frequency of calibration; and

(v) A functional block diagram of the detection system, including the electric power supply.

53 FR 10690, Apr. 1, 1988, as amended at [61 FR 60026, Nov. 26, 1996]

§ 250.292 Additional production and fuel gas system requirements.

(a) *General.* Lessees shall comply with the following production safety system requirements (some of which are in addition to those contained in § 250.291 of this part).

(b) *Design, installation, and operation of additional production systems, including fuel gas handling safety systems.* (1) Pressure and fired vessels shall be designed, fabricated, code stamped, and maintained in accordance with applicable provisions of section I, IV, and VIII of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(i) Pressure safety relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code. The safety relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the safety relief valves shall be set no higher than the maximum-allowable working pressure of the vessel. All safety relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

(ii) The lessee shall use pressure recorders to establish the operating pressure ranges of pressure vessels in order to establish the pressure-sensor settings. Pressure-recording charts used to determine operating pressure ranges shall be maintained by the lessee for a period of 2 years at the lessee's field office nearest the OCS facility or at another location conveniently available to the District Supervisor. The high-pressure sensor shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the vessel. This setting shall also be set sufficiently below (15 percent or 5 psi, whichever is greater) the safety relief valve's set pressure to assure that the high-pressure sensor sounds an alarm before the safety relief valve starts relieving. The low-pressure sensor shall sound an alarm no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range.

(2) *Engine exhaust.* Engine exhausts shall be equipped to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4). Exhaust piping from diesel engines shall be equipped with spark arresters.

(3) *Firefighting systems.* Firefighting systems shall conform to subsection 5.2, Fire Water Systems, of API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, and shall be subject to the approval of the District Supervisor. Additional requirements shall apply as follows:

(i) A firewater system consisting of rigid pipe with firehose stations shall be installed. The firewater system shall be installed to provide needed protection, especially in areas where fuel handling equipment is located.

(ii) Fuel or power for firewater pump drivers shall be available for at least 30 minutes of run time during platform shut-in time. If necessary, an alternate fuel or power supply shall be installed to provide for this pump-operating time unless an alternate firefighting system has been approved by the District Supervisor;

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Supervisor determines that the use of a chemical system provides equivalent fire-protection control; and

(iv) A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the facility or structure.

(4) *Fire- and gas-detection system.* (i) Fire (flame, heat, or smoke) sensors shall be installed in all enclosed classified areas. Gas sensors shall be installed in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation that is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit. One approved method of providing adequate ventilation is a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater. Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more

than four of their six possible sides by walls, floors, or ceilings more restrictive to air flow than grating or fixed open louvers and of sufficient size to allow entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500.

(ii) All detection systems shall be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas concentration levels shall be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(iii) A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility that are provided with fuel gas. Living quarters and doghouses not containing a gas source and not located in a classified area do not require a gas detection system.

(iv) The District Supervisor may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems shall be an approved type, designed and installed in accordance with API RP 14C, API RP 14G, and API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms.

(c) *General platform operations.* Safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices shall be taken out of service. Personnel shall monitor the bypassed or blocked out functions until the safety devices are placed back in service. Any safety device that is temporarily out of service shall be flagged by the person taking such device out of service.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60026, Nov. 26, 1996]

§ 250.293 Safety-system testing and records.

(a) *Inspection and testing.* Safety-system devices shall be successfully inspected and tested by the lessee at the interval specified below or more frequently if operating conditions warrant. Testing shall be in accordance with API RP 14C, appendix D or for safety-system devices other than those listed in API RP 14C, Appendix D the analysis technique and documentation specified therein shall be utilized for inspection and testing of these components, and the following:

(1) Safety relief valves on the natural gas feed system for power plant operations such as pressure safety valves shall be inspected and tested for operation at least once every 12 months. These valves shall be either bench tested or equipped to permit testing with an external pressure source.

(2) The following safety devices shall be inspected and tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests:

(i) All pressure safety high or pressure safety low, and

(ii) All level safety high and level safety low controls.

(3) All pumps for firewater systems shall be inspected and operated weekly.

(4) All fire- (flame, heat, or smoke) and gas-detection systems shall be inspected and tested for operation and recalibrated every 3 months provided that testing can be performed in a nondestructive manner.

(5) Prior to the commencement of production, the lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a complete inspection may be conducted.

(b) *Records.* The lessee shall maintain records for a period of 2 years for each safety device installed. These records shall be maintained by the lessee at the lessee's field office nearest the OCS facility or another location conveniently available to the District Supervisor. These records shall be available for MMS review. The records shall show the present status and history of each safety device, including dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

§ 250.294 Safety device training.

Prior to engaging in production operations on a lease and periodically thereafter, personnel installing, inspecting, testing, and maintaining safety devices shall be instructed in the safety requirements of the operations to be performed; possible hazards to be encountered; and general safety considerations to be taken to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available for MMS review.

§ 250.295 Production rates.

Each sulphur deposit shall be produced at rates that will provide economic development and depletion of the deposit in a manner that would maximize the ultimate recovery of sulphur without resulting in waste (e.g., an undue reduction in the recovery of oil and gas from an associated hydrocarbon accumulation).

§ 250.296 Production measurement.

(a) *General.* Measurement equipment and security procedures shall be designed, installed, used, maintained, and tested so as to accurately and completely measure the sulphur produced on a lease for purposes of royalty determination.

(b) *Application and approval.* The lessee shall not commence production of sulphur until the Regional Supervisor has approved the method of measurement. The request for approval of the method of measurement shall contain sufficient information to demonstrate to the satisfaction of the Regional Supervisor that the method of measurement meets the requirements of paragraph (a) of this section.

§ 250.297 Site security.

(a) All locations where sulphur is produced, measured, or stored shall be operated and maintained to ensure against the loss or theft of produced sulphur and to assure accurate and complete measurement of produced sulphur for royalty purposes.

(b) Evidence of mishandling of produced sulphur from an offshore lease, or tampering or falsifying any measurement of production for an offshore lease, shall be reported to the Regional Supervisor as soon as possible but no later than the next business day after discovery of the evidence of mishandling.

PART 251—GEOLOGICAL AND GEOPHYSICAL (G & G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

Sec.

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AUTHORITY: 43 U.S.C. 1331 *et seq.*

SOURCE: 45 FR 6344, Jan. 25, 1980, unless otherwise noted.

§ 251.0 Authority for information collection.

(a) The information collection requirement contained in 30 CFR 251.13 has been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1028–0039. The information is being collected and will be used to determine eligibility for reimbursement from the Government for certain costs. The obligation to respond is required to obtain a benefit.

(b) The information collection requirement contained in § 251.7–2 has been approved by the Office of Management and Budget under 44 U.S.C. 3504(h) and assigned clearance number 1010–0036. The information is being collected and will be used to monitor the progress of activities carried out under an offshore permit. The obligation to respond is mandatory.

(c) The information collection requirements contained in § 251.6 of this part do not require approval by the Office of Management and Budget under 44 U.S.C. 3504(h) because there are fewer than 10 respondents annually.

(d) The information collection requirements contained in 30 CFR 251.11 and 251.12 have been approved by the Office of Management and Budget under 44 U.S.C. 3504(h) and assigned clearance number 1010–0034. The information is being collected for regulatory compliance. This information will be used to inspect and select geological and geophysical data and information collected under a Federal permit offshore. The obligation to respond is mandatory under section 26 of the Outer Continental Shelf Lands Act (43 U.S.C. 1352).

(e) The information collection requirements contained in 30 CFR 251.6–2 have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1010–0049. The information is being collected for regulation compliance. This information will be used to analyze and evaluate planned drilling activities of permittees on the Federal OCS. The obligation to respond is mandatory.

(f) The information collection requirements contained in 30 CFR 251.5 have been approved by the Office of Management and Budget under 44 U.S.C. 3501 *et seq* and assigned clearance number 1010–0048. The information is being collected to evaluate permit applications to conduct prelease exploration offshore and to moonitor activities of scientific exploration conducted under notices to ensure there is no environmental degradation, personal harm, damage to historical or cultural sites, or interference with other uses. The response is required to obtain a benefit.

[47 FR 25331, June 11, 1982, as amended at 48 FR 37968, Aug. 22, 1983; 48 FR 43324, Sept. 23, 1983; 48 FR 46026, Oct. 11, 1983; 48 FR 55457, Dec. 13, 1983; 53 FR 24688, June 30, 1988]

§ 251.1 Purpose.

(a) The Act authorizes the Secretary to prescribe rules and regulations necessary to carry out the provisions of the Act. The primary purpose of the regulations in this part is to prescribe policies, procedures, and requirements for conducting geological and geophysical activities associated with exploration for oil, gas, or sulphur not authorized under a lease in the Outer Continental Shelf (OCS). These activities may take place on unleased lands or on lands under lease to a third party. These activities are limited to geological and geophysical exploration for oil, gas, and sulphur and geological and geophysical research related to oil, gas, or sulphur, which involves the use of solid or liquid explosives or drilling activities. The requirements of the regulations in this part implement the provisions of sections 5, 8(g), 11 (a) and (g), 19, 24, and 26 of the Act. Federal Agencies are exempt from the regulations in this part.

(b) Notwithstanding any other provisions of the regulations in this part, geological and geophysical exploration for OCS minerals other than oil, gas, and sulphur and geological and geophysical research associated with OCS minerals other than oil, gas, and sulphur are governed by the provisions of part 280 of this title.

[53 FR 25256, July 5, 1988]

§ 251.2 Definitions.

When used in this part, the following terms shall have the meaning given below:

(a) *Act* means the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

(b) *Affected local government* means the principal governing body of a locality which is in an affected State and is identified by the Governor of that State as a locality which will be significantly affected by oil and gas activities on the OCS.

(c) *Affected State* means, with respect to any program, plan, lease sale, or other activity proposed, conducted, or approved pursuant to the provisions of the Act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2)(A) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installation or other device permanently or temporarily attached to the seabed;

(3) Which is receiving, or in accordance with the proposed activity, will receive oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to the State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment or a State in which there will be significant changes in the social, governmental, or economic infrastructure resulting from the exploration, development, and production of oil and gas anywhere in the OCS; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oil spill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

(d) *Analyzed geological information* means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, well logs or charts, results and data obtained from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

(e) *Coastal environment* means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone.

(f) *Coastal zone* means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal States. The coastal zone includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches. The coastal zone extends seaward to the outer limit of the United States territorial sea and extends inland from the shoreline to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority of section 305(b)(1) of the Coastal Zone Management Act.

(g) *Coastal Zone Management Act* means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 *et seq.*).

(h) *Cultural resource* means a site, structure, or object of historical or archeological significance.

(i) *Data* means facts and statistics or samples which have not been analyzed or processed.

(j) *Deep stratigraphic test* means drilling which involves the penetration into the sea bottom of more than 50 feet (15.2 meters) of consolidated rock or a total of more than 300 feet (91.4 meters).

(k) *Director* means the Director of the Minerals Management Service, U.S. Department of the Interior or a subordinate authorized to act on the Director's behalf.

(l) *Exploration* means the process of searching for minerals. Exploration activities include but are not limited to: (1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of minerals, and (2) any drilling, whether on or off a geological structure.

(m) *Gas* means any fluid, either combustible or noncombustible, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely; a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

(n) *Geological exploration for mineral resources* means any operation conducted on the OCS which utilizes geological and geochemical techniques, including, but not limited to, core and test drilling, well logging techniques, and various bottom sampling methods to produce information and data on mineral resources, including information and data in support of possible exploration and development activity. The term does not include scientific research.

(o) *Geophysical exploration for mineral resources* means any operation conducted on the OCS which utilizes geophysical techniques, including, but not limited to gravity, magnetic, and various seismic methods, to produce information and data in support of possible exploration and development activity. The term does not include scientific research.

(p) *Geological or geophysical scientific research* means any investigation conducted on the OCS using solid or liquid explosives, or drilling activities for scientific research purposes involving the gathering and analysis of geological or geophysical information and data which are made available to the public for inspection and reproduction at the earliest practicable time.

(q) *Governor* means the Governor of a State, or the person or entity designated by, or pusuant to, State law to exercise the powers granted to a Governor pursuant to the Act.

(r) *Human environment* means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities occurring on the OCS.

(s) *Hydrocarbon occurrences* means the direct or indirect detection during drilling operations of any liquid or gaseous hydrocarbons by examination of well cuttings, cores, gas detector readings, formation fluid tests, wireline logs, or by any other means. The term does not include background gas, minor accumulations of gas, or heavy oil residues on cuttings and cores.

(t) *Information*, when used without a qualifying adjective, includes analyzed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

(u) *Interpreted geological information* means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

(v) *Interpreted geophysical information* means knowledge, often in the form of seismic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

(w) *Lease* means (1) any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, minerals, or (2) the area covered by such authorization, whichever is required by the context.

(x) *Lessee* means the party authorized by a lease, or an approved assignment thereof, to explore for, develop, and produce the leased deposits in accordance with the regulations in part 250 of

this chapter. The term includes all parties holding such authority by or through the lessee.

(y) *Marine environment* means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the OCS.

(z) *Minerals* includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals which are authorized by an Act of Congress to be produced from ''public lands'' as defined in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702).

(aa) *National Environmental Policy Act* means the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*).

(bb) *Notice* means the statement of intent to conduct geological scientific research which involves shallow test drilling activities.

(cc) *OCS Order* means a formal numbered Order, issued by the Director, that implements the regulations contained in this part and specifically applies to operations in an area in the Order.

(dd) *Oil* means any fluid hydrocarbon substance other than gas which is extracted in a fluid state from a reservoir and which exists in a fluid state under the existing temperature and pressure conditions of the reservoir. Oil includes liquefiable hydrocarbon substances such as drip gasoline or other natural condensates recovered or recoverable in a liquid state from produced gas.

(ee) *Operator* means the individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

(ff) *Outer Continental Shelf* means all submerged lands which lie seaward and outside the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301), and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(gg) *Permit* means the contract or agreement, other than a lease, approved for a specified period of not more than 1 year under which a person acquires the right to conduct: (1) Geological exploration for mineral resources, (2) geophysical exploration for mineral resources, (3) geological scientific research, or (4) geophysical scientific research.

(hh) *Permittee* means the person authorized by a permit issued pursuant to this part to conduct activities on the OCS.

(ii) *Person* means a citizen or national of the United States, an alien lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20), a private, public, or municipal corporation organized under the laws of the United States or of any State or territory thereof, and associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States. The term does not include Federal agencies.

(jj) *Pollution contingency plan* means the National Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan or any successor plan thereto.

(kk) *Processed geophysical information* means data collected under a permit or a lease which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

(ll) *Secretary* means the Secretary of the Interior or a subordinate authorized to act on the Secretary's behalf.

(mm) *Shallow test drilling* means drilling into the sea bottom to depths less than those specified in the definition of a deep stratigraphic test.

(nn) *Third party* means any person other than a representative of the United States or the permittee.

(oo) *Violation* means a failure to comply with any provision of the Act, or a

provision of a regulation or order issued under the Act, or any provision of a lease, license, or permit issued pursuant to the Act.

§ 251.3 Administrative authority and applicability.

§ 251.3–1 Administrative authority.

Exploration or scientific research activities authorized or conducted under this part shall be performed in accordance with the Act, the regulations in this part, OCS Orders, other orders of the Director, and other applicable statutes and regulations, and amendments thereto.

§ 251.3–2 Functions of Director.

The Director shall regulate all operations and other activities under this part and perform all duties prescribed by this part. The Director is authorized to issue OCS Orders and other written and oral orders and to take all other actions necessary to carry out the provisions of this part and to prevent harm or damage to, or waste of, any natural resource (including any mineral deposit in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment. The Director shall confirm oral orders in writing as soon as possible.

§ 251.3–3 Geological and geophysical activities under a lease.

The regulations in this part shall not apply to geological and geophysical exploration conducted by or on behalf of the lessee on a lease on the OCS. Those exploration activities shall be governed by the regulations in part 250 of this title.

§ 251.3–4 Geological and geophysical activities not under a lease.

The regulations in this part are applicable to permits for geological and geophysical activities issued after or unexpired as of the effective date of this final rule. Notices filed after the effective date of this final rule shall also be subject to the regulations in this part. If the regulations in this part conflict with the provisions of a permit which was issued under regulations published in the FEDERAL REGISTER on June 23, 1976 (41 FR 25893), the requirements of the permit shall govern, except for any requirements limiting the Director's authority to inspect and require the submission of interpretations derived from information and data acquired under those permits issued after January 27, 1978, as established by part 252 of this title.

§ 251.3–5 General requirements of notices and permits.

(a) Geological or geophysical activities for mineral exploration or scientific research activities authorized under this part shall be conducted so that those activities do not:

(1) Interfere with or endanger operations under any lease issued or maintained pursuant to the Act;

(2) Cause harm or damage to aquatic life;

(3) Cause pollution;

(4) Create hazardous or unsafe conditions;

(5) Unreasonably interfere with or harm other uses of the area; or

(6) Disturb cultural resources.

(b) Any person conducting geological or geophysical activities for mineral exploration or scientific research under this part shall immediately report to the Director when these activities:

(1) Detect hydrocarbon occurrences;

(2) Encounter evironmental hazards which constitute an imminent threat to human activity; or

(3) Adversely affect the environment, aquatic life, cultural resources, or other uses of the area in which the exploration activity is conducted.

(c) Any person conducting shallow test drilling or deep stratigraphic test drilling geological activities under a permit for mineral exploration or scientific research under this part shall utilize the best available and safest technologies which the Director determines to be economically feasible.

(d) Authorization granted under this part to conduct geological and geophysical exploration for minerals or for scientific research shall not confer a right to any discovered oil, gas, or other minerals, or to a lease under the Act.

§ 251.4 Geological and geophysical activities requiring notices or permits.

§ 251.4–1 Geological and geophysical exploration for mineral resources.

Geological or geophysical exploration for mineral resources may not be conducted on the OCS without an approved permit unless such activities are being conducted pursuant to a lease issued or maintained under the Act. Separate permits must be obtained for geological exploration for mineral resources and for geophysical exploration for mineral resources. If the Director disapproves an application, the statement of rejection shall state the reasons for the denial, and shall advise the applicant of those changes needed to obtain approval.

§ 251.4–2 Geological or geophysical scientific research.

Geological or geophysical scientific research may not be conducted by any person on the OCS without an approved permit or filing of a notice unless such activities are being conducted pursuant to a lease issued or maintained under the Act.

(a) Separate permits must be obtained for geological scientific research and for geophysical scientific research which involves the use of solid or liquid explosives or the drilling of a deep stratigraphic test. If the Director disapproves an application, the statement of rejection shall state the reasons for the denial, and shall advise the applicant of the changes needed to obtain approval.

(b) A notice must be filed with the Director at least 30 days prior to the commencement of scientific research activities which involve shallow test drilling. Within 21 days of the filing of the notice, the Director may disapprove the notice by sending a statement of disapproval by certified mail to the person who filed the notice. If the Director disapproves the notice, the statement shall state the reasons for disapproval and shall advise the applicant of recommended changes.

§ 251.5 Applying for notices or permits.

§ 251.5–1 Permit forms.

(a) An application for a permit shall be submitted in a form and manner prescribed and approved by the Director. Each application for a permit shall include:

(1) The name of any person who will conduct the proposed exploration or research activity;

(2) The name of any person who will participate in the proposed exploration or research activity;

(3) The type of exploration or research activity and the manner in which the activity will be conducted;

(4) The location on the OCS where the exploration or research activity will be conducted;

(5) The purpose for conducting the exploration or research activity;

(6) The dates on which the exploration or research activity is proposed to be commenced and completed; and,

(7) Such other relevant information and data as the Director may require.

[45 FR 6344, Jan. 25, 1980, as amended at 53 FR 24688, June 30, 1988]

§ 251.5–2 Notices.

A notice shall not be on a standardized form, but shall be signed and shall state:

(a) The name of the person conducting or participating in the proposed research;

(b) The type of research and manner in which it will be conducted;

(c) The location, designated on a map, plat, or chart, where the research will be conducted;

(d) The dates, which shall designate a period of not more than 1 year, on which the research activity is proposed to be commenced and completed;

(e) The proposed time and manner in which the information and data resulting from the research will be made available to the public for inspection and reproduction, such time being the earliest practicable time;

(f) An agreement that the information and data resulting from the research will not be sold or withheld for exclusive use; and

(g) The name, registry number, registered owner, and port of registry of vessels used in the operation.

§ 251.5–3 Filing locations for permits to conduct exploration for mineral resources.

Each application for a permit to conduct geological or geophysical exploration for mineral resources in the OCS shall be filed, in duplicate, at the following locations:

(a) For the OCS off the Atlantic Coast—the Regional Supervisor for Resource Evaluation, Atlantic OCS Region, Minerals Management Service, 381 Elden Street, Herndon, Virginia 22070—4817.

(b) For the OCS in the Gulf of Mexico—the Regional Supervisor for Resource Evaluation, Minerals Management Service, Gulf of Mexico OCS Region, 1201 Elmwood Park Blvd., New Orleans, Louisiana 70123.

(c) For the OCS off the coast of the States of California, Oregon, or Washington—the Regional Supervisor for Resource Evaluation, Minerals Management Service, Pacific OCS Region, 1340 West Sixth Street, Los Angeles, California 90017.

(d) For the OCS off the State of Alaska—the Regional Supervisor for Resource Evaluation, Minerals Management Service, Alaska OCS Region, 949 East 36th Avenue, Anchorage, Alaska 99508.

[53 FR 4392, Feb. 16, 1988, as amended at 54 FR 50617, Dec. 8, 1989]

§ 251.5–4 Filing locations for notices or permits to conduct scientific research.

Each notice or application for a permit to conduct geological or geophysical scientific research on the OCS shall be filed, in duplicate, at the locations indicated in § 251.5–3 of this part.

§ 251.6 Test drilling activities.

§ 251.6–1 Permit or notice requirements for shallow test drilling.

The Director, prior to the commencement of shallow test drilling for exploration for mineral resources or for scientific research, may require for permits or recommend for notices the gathering and submission of geophysical information and data sufficient to determine shallow structural detail across and in the vicinity of the proposed test. Other information and data may include, but is not limited to, seismic, bathymetric, side-scan sonar, and magnetometer systems, across and in the vicinity of the proposed test. When required, §§ 251.6–2 (c)(1) and (e) and 251.6–3 will apply to permits issued and notices filed for shallow test drilling.

§ 251.6–2 Permit requirements for a deep stratigraphic test.

(a) No deep stratigraphic test drilling activities shall be initiated or conducted until a Drilling Plan has been submitted by the applicant and approved by the Director. The Drilling Plan shall include:

(1) The proposed type and sequence of drilling activities to be undertaken together with a timetable for their performance from commencement to completion;

(2) A description of the drilling rig proposed for use, unless a description has been previously submitted to the Director, indicating the important features thereof, with special attention to safety features and pollution prevention and control features, including oil spill containment and cleanup plans and onshore disposal procedures;

(3) The location of each deep stratigraphic test to be conducted, including the surface and projected bottomhole location of the borehole;

(4) The types of geophysical instrumentation to be used;

(5) Geophysical information and data sufficient to evaluate seafloor characteristics, shallow geologic hazards, and structural detail across and in the vicinity of the proposed test to the total depth of the proposed test well. Data and information from side-scan sonar and magnetometer surveys shall be submitted as required, at the option of the Director; and

(6) Such other relevant information and data as the Director may require.

(b) At the same time the applicant submits a Drilling Plan to the Director, an Environmental Report shall be submitted. The report shall be in summary form and should include information available at the time the related

Drilling Plan is submitted. Information and data which are site-specific or which are developed subsequent to the most recent environmental impact statement or other environmental impact statements and analyses in the immediate area, shall be specifically considered. In order to eliminate the repetition of information and data discussed in the related plan, a broader presale environmental impact statement, other Environmental Reports, environmental analyses, or impact statements prepared for the geographic area, the applicant shall summarize the information, data, and issues in such other documents and concentrate on the issues specific to the site(s) of drilling activity. Discussions contained in the other documents shall be referenced when incorporation will cause a decrease in bulk without impeding review of the issues. The material referred to shall be cited and described briefly in the Environmental Report and include a statement of where the material is reasonably available for inspection. Any material based on proprietary data which is not itself available for inspection shall not be referenced. The Environmental Report shall include the following:

(1)(i) A list and description of new or unusual technologies that are to be used; (ii) the location of travel routes for supplies and personnel; (iii) the kinds and approximate quantities of energy to be used; (iv) the environmental monitoring systems that are to be used; and (v) suitable maps and diagrams showing details of the proposed project layout.

(2) A narrative description of the existing environment. This section shall include the following information on the area: (i) Geology; (ii) physical oceanography; (iii) other uses of the area; (iv) flora and fauna; (v) existing environmental monitoring systems; and (vi) other unusual or unique characteristics which may affect or be affected by the drilling activities.

(3) A narrative description of the probable impacts of the proposed action on the environment and the measures proposed for mitigating these impacts.

(4) A narrative description of any unavoidable or irreversible adverse effects on the environment that could be expected to occur as a result of the proposed action.

(5) Such other relevant information and data as the Director may require.

(c)(1) When required under a coastal zone management program approved under the Coastal Zone Management Act, the activities proposed by an applicant for a permit to conduct geological or geophysical exploration for minerals or for geological or geophysical scientific research must receive State concurrence in its coastal zone consistency certification prior to the Director's approval of any of the activities covered under the permit.

(2) The applicant shall submit a sufficient number of copies of the Drilling Plan and Environmental Report to permit the Director to transmit copies of each to the Governor of each affected State and the coastal zone management agency of each affected State that has a coastal zone management program approved under the Coastal Zone Management Act. The Director shall also make the Drilling Plan and accompanying Environmental Report available to appropriate Federal agencies and the public, in accordance with established Departmental practices and procedures.

(d) Any revisions to an approved Drilling Plan must be approved by the Director.

(e) A permittee authorized to drill a deep stratigraphic test shall, if requested by the Director, conduct studies to determine whether any cultural resources exist in the area that may be affected by such drilling, and shall report the findings of those studies to the Director. A permittee authorized to perform shallow test drilling may be required to conduct similar studies if required by the Director. The study shall include a full description of any cultural resources detected. The permittee shall take no action that will result in the disturbance of cultural resources without the prior approval of the Director and, if any cultural resource is discovered after submission of the study (i.e., during site preparation or drilling), the permittee shall immediately report the discovery to the Director and make every reasonable effort to protect the cultural resource

from damage until the Director has given directions as to its preservation.

(f) All OCS regulations relating to drilling operations in part 250 of this title and all OCS Orders relating to the drilling of wells apply, as appropriate, to drilling activities authorized under this part.

(g) At the completion of the test activities, the borehole of all deep stratigraphic tests shall be permanently plugged and abandoned by the permittee prior to moving the rig off location in accordance with the requirements of the regulations in part 250 of this chapter and applicable orders. If the tract on which deep stratigraphic test drilling has been conducted is later leased for exploration and development, the lessee will not be held responsible for the test hole, provided the lessee has not reentered or otherwise disturbed the borehole.

[45 FR 6344, Jan. 25, 1980, as amended at 48 FR 54008, Nov. 30, 1983; 48 FR 55457, Dec. 13, 1983]

§ 251.6–3 Group participation in test drilling activities.

(a) In order to minimize duplicative geological exploration activities involving the penetration of the seabed of the OCS, a person proposing to drill a deep stratigraphic test shall afford all interested persons, through a signed agreement, an opportunity to participate in the drilling on a cost-sharing basis. The provisions of the agreement for sharing the cost of a deep stratigraphic test may include a penalty for late participants of not more than 100 percent of the cost to each original participant in addition to the original share cost. The participants shall assess and distribute penalties in accordance with the terms of the agreement. If the Director releases a public notice announcing a significant hydrocarbon occurrence, the penalty for subsequent late participants may be raised to not more than 300 percent of the cost of each original participant in addition to the original share cost.

(b) An applicant proposing to conduct shallow test drilling activities shall, when ordered by the Director or when provided in the permit, afford all interested persons an opportunity to participate in the test activity on a cost-sharing basis with a penalty for late participation of not more than 50 percent of the cost to each original participant.

(c) To allow for group participation in shallow or deep test drilling activities, the applicant shall:

(1) Publish a summary statement describing the proposed activity in a manner approved or prescribed by the Director;

(2) Forward a copy of the published statement to the Director;

(3) Allow at least 30 days from the date of publishing the summary statement for other persons to join as original participants;

(4) Compute the estimated cost to an original participant by dividing the estimated total cost of the program by the number of original participants; and

(5) Furnish the Director with a complete list of all participants under the permit prior to commencing operations, or at the end of the advertising period if operations begin prior to its close. Also, the names of all late participants shall be forwarded to the Director.

(d) If the applicant proposes changes to the original application and the Director determines that such changes are significant, the Director shall require a republication of the changes and an additional 30 days for other persons to join as original participants.

[45 FR 6344, Jan. 25, 1980, as amended at 54 FR 50617, Dec. 8, 1989]

§ 251.6–4 Bonds.

(a) When you apply to the Minerals Management Service (MMS) for a permit authorizing the drilling of a deep stratigraphic test well, you must either:

(1) Furnish a bond of not less than $200,000 that guarantees compliance with all the terms and conditions of the permit; or

(2) Maintain a $1 million bond that guarantees compliance with all the terms and conditions of the permits you hold for the OCS area where you propose to drill.

(b) You must provide additional security to MMS if the Regional Director determines that it is necessary for the permit or area.

(c) The Regional Director may require you to provide a bond, in an amount the Regional Director prescribes, before authorizing you to drill a shallow test well.

(d) Your bond must be on a form approved by the Associate Director for Offshore Minerals Management.

[62 FR 27955, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27955, May 22, 1997, § 251.6–4 was revised, effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 251.6–4 Bonds.

Before a permit authorizing the drilling of a deep stratigraphic test will be issued, the applicant shall furnish to the Minerals Management Service a corporate surety bond of not less than $50,000 conditioned on compliance with the terms of the permit, unless the applicant maintains with or furnishes to the Minerals Management Service a bond in the sum of $300,000 conditioned on compliance with the terms of the permit issued to him for the area of the OCS where the applicant proposes to conduct the drilling of a deep stratigraphic test. The Director may require the submission of a bond before authorizing the initiation of shallow test drilling. Any bond furnished or maintained by a person under this section shall be on a form approved or prescribed by the Director, Minerals Management Service.

§ 251.6–5 Duration of exploration activities.

If a deep stratigraphic test well is drilled within 50 geographic miles of any tract within the area identified for consideration for leasing as listed on the currently approved OCS Leasing Schedule, all drilling activities must be completed, and the information and data submitted to the Director at least 60 days prior to the first day of the month in which the lease sale is scheduled to be held. However, the Director may extend the expiration date of a permit if it is determined that such an extension is in the national interest.

[47 FR 15782, Apr. 13, 1982]

§ 251.7 Inspection and reporting of progress and results of activities conducted under permits.

§ 251.7–1 Inspection and observation of exploration activities.

(a) A permittee, upon request by the Director, shall furnish food, quarters, and transportation for Federal representatives. Upon request, the permittee will be reimbursed by the United States for the actual costs incurred as a result of providing food, quarters, and transportation for a Federal representative's stay of more than 10 hours. The Federal representative shall observe or inspect operations conducted pursuant to the permit and determine whether operations are having any adverse effects upon the environment, aquatic life, cultural resources, or other uses of the area.

(b) The Federal representatives shall be appointed or approved by the Director.

§ 251.7–2 Progress report on activities conducted under a permit.

Each permittee shall submit status reports on a monthly basis in a manner approved or prescribed by the Director. This shall include a daily log of operations.

[48 FR 37968, Aug. 22, 1983; 48 FR 40380, Sept. 7, 1983]

§ 251.7–3 Final report on activities conducted under a permit.

Each permittee shall submit to the Director a final report of exploration or scientific research activities under the permit within 30 days after the completion of operations. The final report shall contain the following:

(a) A description of the work performed.

(b) Charts, maps, or plats depicting the areas and blocks in which any exploration or scientific research activities were conducted, specifically identifying the lines of geophysical traverses or the locations where geological exploration or scientific research activities were conducted, including a

reference sufficient to identify the data produced during each activity.

(c) The dates on which the actual exploration or scientific research activities were performed.

(d) A narrative summary of any: (1) Hydrocarbon occurrences or environmental hazards, and (2) adverse effects of the exploration or scientific research activities on the environment, aquatic life, cultural resources, or other uses of the area in which the activities were conducted.

(e) Such other descriptions of the activities conducted as may be specified by the Director.

§ 251.8 Suspension and cancellation of authority to conduct activities under permit.

(a) The Director may suspend or temporarily prohibit the permittee's authority to conduct exploration or scientific research activities under a permit by notifying the permittee either orally or in writing when the Director determines that there is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment. Such suspensions shall be effective immediately upon receipt of the notice. Suspensions issued orally shall be followed by a written notice confirming the action, and all written notices will be sent by certified mail. A suspension shall remain in effect until the basis for the suspension has been corrected to the satisfaction of the Director.

(b) The Director may suspend or temporarily prohibit the permittee's authority to conduct exploration or scientific research under a permit either orally or in writing when the Director determines the permittee fails to comply with a provision of the Act or of any applicable law, the provisions of the permit, provisions of these and other applicable regulations, OCS Orders, or any other written orders or field rules including orders for the filing of reports and well records or logs within the time specified. Such suspensions shall be effective immediately upon receipt of the notice. Suspensions issued orally shall be followed by a written notice confirming the action and all written notices shall be sent by certified mail. A suspension shall remain in effect until the basis for the suspension has been corrected to the satisfaction of the Director.

(c)(1) The Director may cancel, or a permittee may relinquish, a permit to conduct exploration or scientific research activities at any time by sending a notice of cancellation or a notice of relinquishment. Such notices shall state the reason for the cancellation or relinquishment and shall be sent by certified mail to the other party at least 30 days in advance of the date the cancellation or relinquishment will be effective.

(2) Cancellation of a permit to conduct exploration or scientific research activities shall not relieve the permittee of the obligation to abandon any drill sites in accordance with the requirements of § 251.6–2(g) of this part and to comply with all other obligations specified in this part or in the permit.

§ 251.9 Penalties.

All persons conducting geological or geophysical exploration activities for mineral resources or scientific research shall be subject to the penalty provisions of section 24 of the Act (43 U.S.C. 1350), the procedures contained in § 250.80 of this chapter for noncompliance with any provision of the Act, or any provision of the permit, or for any violation of the provisions of any regulation or order issued under the Act. The penalties prescribed in this section shall be in addition to any other penalty afforded by any other law or regulation.

§ 251.10 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in part 290 of this chapter.

§ 251.11 Inspection, selection, and submission of geological information and data.

(a) Each holder of a permit for geological exploration activities for mineral resources or scientific research shall notify the Director in writing

within 30 days of the acquisition, initial analysis, and initial interpretation of any geological information and data collected under the permit. Within 30 days following the receipt of the Director's request for notice of any subsequent analysis and interpretation of that geological information or data, the permittee shall submit notice of the availability of that information in writing.

(b) Each submission of geological data, analyzed geological information, and interpreted geological information shall contain, unless otherwise specified by the Director, the following:

(1) An accurate and complete record of all geological (including geochemical) data, analyzed geological information, and interpreted geological information resulting from each operation;

(2) Paleontological reports identifying microscopic fossils by depth, unless washed samples are maintained by the permittee for paleontological determination and are made available upon request for inspection by the Minerals Management Service;

(3) Copies of well logs or charts;

(4) Results and data obtained from formation fluid tests;

(5) Analyses of core or bottom samples or a representative cut or split of the core or bottom sample;

(6) Detailed descriptions of any hydrocarbons or hazardous conditions encountered during operations, including near losses of well-control, abnormal geopressures, and losses of circulation; and

(7) Such other geological data, analyzed geological information, and interpreted geological information as may be specified by the Director.

(c) In the event that geological data, analyzed geological information, or interpreted geological information is transferred from the permittee to a third party, or from a third party to another third party, the transferor shall notify the Director and shall require the receiving party, in writing, to abide by the obligations of the permittee as specified in this section as a condition precedent to the transfer of information or data.

[45 FR 6344, Jan. 25, 1980, as amended at 48 FR 46026, Oct. 11, 1983]

§ 251.12 Inspection, selection, and submission of geophysical information and data.

(a) Each holder of a permit for geophysical exploration activities for mineral resources or scientific research shall notify the Director in writing within 30 days of the acquisition, initial processing, and initial interpretation of any geophysical information and data collected under the permit. Within 30 days following the receipt of the Director's request for notice of any reprocessing or subsequent interpretation of that geophysical information or data, the permittee shall submit notice of the availability of that information in writing.

(b) The Director shall have the right to inspect geophysical data, processed geophysical information, reprocessed geophysical information, or interpreted geophysical information prior to final selection. This inspection shall be performed on the permittee's premises unless the Director requests that the permittee deliver the information or data to the Director for inspection. Such delivery shall be within 30 days following the receipt of the Director's request unless the Director authorizes a later delivery date. At any time prior to final selection, the Director may return any or all geophysical information or data following either its inspection and detailed assessment of its quality, or the establishment of a price to the Government for the processing or reprocessing of the geophysical information or data. If the Director decides to keep all or a portion of the geophysical information and data, the Director shall notify the permittee, in writing, of this decision. If the inspection is done on the permittee's premises, the permittee shall submit the geophysical information or data selected within 30 days following receipt of the Director's request, unless the Director authorizes a longer period of time for delivery. The Director shall have the right to arrange, by contract or otherwise, for the reproduction, without the consent of the permittee, of geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information.

(c) In the event that geophysical data, processed geophysical information, reprocessed geophysical information, or interpreted geophysical information is transferred from the permittee to a third party, or from a third party to another third party, the transferor shall notify the Director and shall require the receiving third party, in writing, to abide by the obligations of the permittee as specified in this section as a condition precedent to the transfer of information or data.

(d) Each submission of geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information, shall contain, unless otherwise specified by the Director, the following:

(1) An accurate and complete record of each geophysical survey conducted under the permit, including digital navigational data and final location maps of all survey stations;

(2) All seismic data developed under a permit presented in a format and of a quality suitable for processing;

(3) Processed geophysical information derived from seismic data with extraneous signals and interference removed, presented in a format and of a quality suitable for interpretive evaluation, reflecting state-of-the-art processing techniques; and

(4) Other geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information obtained from, but not limited to, shallow and deep subbottom profiles, bathymetry, sidescan sonar, gravity and magnetic surveys, and special studies such as refraction and velocity surveys.

[45 FR 6344, Jan. 25, 1980, as amended at 48 FR 46026, Oct. 11, 1983]

§ 251.13 Reimbursement to permittees.

(a) After the delivery to the Director of geological data, analyzed geological information, interpreted geological information, geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information selected by the Director in accordance with §§ 251.11 or 251.12, and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the permittee or third party shall be reimbursed for the reasonable costs of reproducing the selected information and data at the permittee's or third party's lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) After the delivery to the Director of processed or reprocessed geophysical information selected and retained by the Director in accordance with § 251.12(b) and upon receipt of a request for reimbursement and a determination that the requested reimbursement is proper, the permittee or third party shall be reimbursed for the reasonable costs attributable to processing and reprocessing such information (as distinguished from the cost of data acquisition) if the processing or reprocessing was in the form and manner of processing other than that used in the normal conduct of business at the Director's request.

(c) Requests for reimbursement shall identify processing and reprocessing costs separate from acquisition costs.

(d) The permittee or third party shall not be reimbursed for the costs of analyzing geological information or interpreting geological or geophysical information.

[47 FR 25331, June 11, 1982, as amended at 51 FR 17176, May 9, 1986]

§ 251.14 Disclosure of information and data submitted under permits.

§ 251.14–1 Disclosure of information and data to the public.

(a) The Director shall make information and data available in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR part 2), the requirements of the Act, and the regulations contained in 30 CFR part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), this part, and 30 CFR part 252 (Outer Continental Shelf Oil and Gas Information Program).

(b) Except as specified in this section or in parts 250 and 252 of this chapter, no information or data determined by the Director to be exempt from public

disclosure under paragraph (a) of this section shall be provided to any affected State or be made available to the executive of any affected local government or to the public unless the permittee and all persons to whom such permittee has sold the information or data under promise of confidentiality agree to such an action.

(c) The Director shall disclose geological data, analyzed geological information, and interpreted geological information submitted under a permit as follows:

(1) The Director shall immediately issue a public announcement when any significant hydrocarbon occurrences are detected or environmental hazards are encountered on unleased lands during drilling operations. In the case of significant hydrocarbon occurrences, the Director will announce such occurrences in a form and manner that will further the national interest without unduly damaging the competitive position of those conducting the drilling. Other information and data pertaining to the permit will be released according to the schedule provided in paragraph (c)(2) or (3) of this section.

(2) The Director shall make available to the public all geological data, analyzed geological information, and interpreted geological information, except geological data, analyzed geological information, and interpreted geological information obtained from the drilling of a deep stratigraphic test, 10 years after the date of issuance of the permit under which the information and data was obtained.

(d) The Director shall disclose geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geophysical information submitted under a permit, and retained by the Director, as follows:

(1) The Director shall make geophysical data available to the public 50 years after the date which the data are submitted.

(2) The Director shall make processed geophysical information, reprocessed geophysical information, and interpreted geophysical information available to the public 25 years after the date which the information is submitted.

(e) The Director shall make available to the public all geological and geophysical data and information and geophysical interpretations obtained from drilling a deep stratigraphic test or submitted in support of an application for a permit to drill a deep stratigraphic test, or which the permittee is required to obtain in order to conduct the drilling of a deep stratigraphic test, at the earliest of the following times: (1) 25 years after completion of the test, or (2) for a lease sale held after the test well is completed, 60 calendar days after the Department of the Interior executes the first lease for a block, any part of which is within 50 geographic miles (92.6 kilometers) of the site of the completed test.

[45 FR 6344, Jan. 25, 1980, as amended at 53 FR 4392, Feb. 16, 1988]

§ 251.14–2 Disclosure to independent contractors.

The Director reserves the right to disclose any information or data acquired from a permittee to an independent contractor or agent for the purpose of reproducing, processing, reprocessing, or interpreting such information or data. When practicable, the Director shall notify the permittee who provided the information or data of intent to disclose the information or data to an independent contractor or agent. The Director's notice of intent will afford the permittee a period of not less than 5 working days within which to comment on the intended action. When the Director so notifies a permittee of the intent to disclose information or data to an independent contractor or agent, all other owners of such information or data shall be deemed to have been notified of the Director's intent. Prior to any such disclosure, the contractor or agent shall be required to execute a written commitment not to transfer or to otherwise disclose any information or data to anyone without the express consent of the Director. The contractor or agent shall be liable for any unauthorized use by or disclosure of information or data to third parties.

§ 251.14–3 Sharing of information with affected States.

(a) At the time of soliciting nominations for the leasing of lands within 3 geographic miles of the seaward boundary of any coastal State, the Director, pursuant to the provisions of § 252.7(a)(4) and (b) of this chapter and sections 8(g) and 26(e) of the Act, shall provide the Governor of the State the following information that has been acquired by the Director on such lands proposed to be offered for leasing:

(1) All information on the geographical, geological, and ecological characteristics of the areas and regions proposed to be offered for leasing;

(2) An estimate of the oil and gas reserves in the areas proposed for leasing; and

(3) An identification of any field, geological structure, or trap located within 3 miles of the seaward boundary of the State.

(b) After the time of receipt of nominations for any area of the OCS within 3 geographic miles of the seaward boundary of any coastal State and tentative tract selection in accordance with the provisions of 43 CFR parts 3313 and 3314, the Director, in consultation with the Governor of the State, shall determine whether any tracts being given further consideration for leasing may contain one or more oil or gas reservoirs underlying both the OCS and lands subject to the jurisdiction of the State.

(c) At any time prior to a sale, information acquired by the Director that pertains to the identification of oil or gas pools or fields underlying both the Outer Continental Shelf and lands subject to the jurisdiction of any coastal State on tracts selected for leasing within 3 geographic miles of the seaward boundary of any such State will be shared, upon request and pursuant to the provisions of § 252.7(a)(4) and (b) of this chapter and sections 8(g) and 26 of the Act, with the Governor of such State.

(d) Knowledge obtained by a State official who receives information under paragraphs (a) and (b) of this section shall be subject to the requirements and limitations of the Freedom of Information Act (5 U.S.C. 552) and the implementing regulations (43 CFR part 2), the Act, the regulations contained in 30 CFR part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations in this part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in 30 CFR part 252 (Outer Continental Shelf Oil and Gas Information Program).

§ 251.14–4 Disclosure of information and data relating to specific contractual commitments.

All information and data already received by the Director and covered by a specific contractual commitment concerning its release shall be handled in a way consistent with the contractual commitment. In the event of any conflict between this provision and a provision of any other regulation in this part 251, or of any regulation in part 250 of this chapter, this provision shall govern.

PART 252—OUTER CONTINENTAL SHELF (OCS) OIL AND GAS INFORMATION PROGRAM

Sec.

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252.2 Definitions.
252.3 Oil and gas data and information to be provided for use in the OCS Oil and Gas Information Program.
252.4 Summary Report to affected States.
252.5 Information to be made available to affected States.
252.6 Freedom of Information Act requirements.
252.7 Privileged and proprietary data and information to be made available to affected States.

AUTHORITY: OCS Lands Act, 43 U.S.C. 1331 et seq., as amended, 92 Stat. 629; Freedom of Information Act, 5 U.S.C. 552; § 252.3 also issued under Pub. L. 99–190 making continuing appropriations for Fiscal Year 1986, and for other purposes.

SOURCE: 44 FR 46408, Aug. 7, 1979, unless otherwise noted.

§ 252.1 Purpose.

The purpose of this part is to implement the provisions of section 26 of the Act (43 U.S.C. 1352). This part supplements the procedures and requirements contained in parts 250 and 251 of this chapter and provides procedures and requirements for the submission of oil

and gas data and information resulting from exploration, development, and production operations on the Outer Continental Shelf (OCS) to the Director, Minerals Management Service. In addition, this part establishes procedures for the Director to make available certain information to the Governors of affected States and, upon request, to the executives of affected local governments in accordance with the provisions of the Freedom of Information Act and the Act.

§ 252.2 Definitions.

When used in the regulations in this part, the following terms shall have the meanings given below:

(a) *Act* refers to the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

(b) *Affected local government* means the principal governing body of a locality which is in an affected State and is identified by the Governor of that State as a locality which will be significantly affected by oil and gas activities on the OCS.

(c) *Affected State* means, with respect to any program, plan, lease sale, or other activity, proposed, conducted, or approved pursuant to the provisions of the Act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2)(A) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installations and other devices permanently, or temporarily attached to the seabed;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Director as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the OCS; or

(5) In which the Director finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oilspill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

(d) *Analyzed geological information* means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, logs or charts of electrical, radioactive, sonic, and other well logs, and descriptions of hydrocarbon shows or hazardous conditions.

(e) *Area adjacent to a State* means all of that portion of the OCS included within a planning area if such planning area is bordered by that State. The portion of the OCS in the Navarin Basin Planning Area is deemed to be adjacent to the State of Alaska. The States of New York and Rhode Island are deemed to be adjacent to both the Mid-Atlantic Planning Area and the North Atlantic Planning Area.

(f) *Data* means facts and statistics or samples which have not been analyzed or processed.

(g) *Development* means those activities which take place following discovery of oil or natural gas in paying quantities, including geophysical activity, drilling, platform construction, and operation of all onshore support facilities, and which are for the purpose of ultimately producing the oil and gas discovered.

(h) *Director* means the Director of the Minerals Management Service of the U.S. Department of the Interior or a designee of the Director.

(i) *Exploration* means the process of searching for oil and natural gas, including: (1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of such oil or natural gas, and (2) any drilling, whether on or off

known geological structures, including the drilling of a well in which a discovery of oil or natural gas in paying quantities is made and the drilling of any additional delineation well after such discovery which is needed to delineate any reservoir and to enable the lessee to determine whether to proceed with development and production.

(j) *Governor* means the Governor of a State, or the person or entity designated by, or pursuant to, State law to exercise the powers granted to a Governor pursuant to the Act.

(k) *Information*, when used without a qualifying adjective, includes analyzed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

(l) *Interpreted geological information* means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

(m) *Interpreted geophysical information* means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

(n) *Lease* means any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, oil or natural gas, or the land covered by such authorization, whichever is required by the context.

(o) *Lessee* means the party authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in part 250 of this chapter, including all parties holding such authority by or through the lessee.

(p) *Outer Continental Shelf (OCS)* means all submerged lands which lie seaward and outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (67 Stat. 29) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(q) *Permittee* means the party authorized by a permit issued pursuant to part 251 of this chapter to conduct activities on the OCS.

(r) *Processed geophysical information* means data collected under a permit or a lease which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processsing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

(s) *Production* means those activities which take place after the successful completion of any means for the removal of oil or natural gas, including such removal, field operations, transfer of oil or natural gas to shore, operation monitoring, maintenance, and workover drilling.

(t) *Secretary* means the Secretary of the Interior or a designee of the Secretary.

[44 FR 46408, Aug. 7, 1979, as amended at 49 FR 10670, Mar. 22, 1984; 51 FR 10382, Mar. 26, 1986]

§ 252.3 Oil and gas data and information to be provided for use in the OCS Oil and Gas Information Program.

(a) Any permittee or lessee engaging in the activities of exploration for, or development and production of, oil and gas on the OCS shall provide the Director access to all data and information obtained or developed as a result of such activities, including geological data, geophysical data, analyzed geological information, processed and reprocessed geophysical information, interpreted geophysical information, and interpreted geological information. Copies of these data and information and any interpretation of these data and information shall be provided to the Director upon request. No permittee or lessee submitting an interpretation of data or information, where such interpretation has been submitted in good faith, shall be held responsible for any consequence of the use of or reliance upon such interpretation.

(b)(1) Whenever a lessee or permittee provides any data or information, at

the request of the Director and specifically for use in the OCS Oil and Gas Information Program in a form and manner of processing which is utilized by the lessee or permittee in the normal conduct of business, the Director shall pay the reasonable cost of reproducing the data and information if the lessee or permittee requests reimbursement. The cost shall be computed and paid in accordance with the applicable provisions of paragraph (e)(1) of this section.

(2) Whenever a lessee or permittee provides any data or information, at the request of the Director and specifically for use in the OCS Oil and Gas Information Program, in a form and manner of processing not normally utilized by the lessee or permittee in the normal conduct of business, the Director shall pay the lessee or permittee, if the lessee or permittee requests reimbursement, the reasonable cost of processing and reproducing the requested data and information. The cost is to be computed and paid in accordance with the applicable provisions of paragraph (e)(2) of this section.

(c) Data or information requested by the Director shall be provided as soon as practicable, but not later than 30 days following receipt of the Director's request, unless, for good reason, the Director authorizes a longer time period for the submission of the requested data or information.

(d) The Director reserves the right to disclose any data or information acquired from a lessee or permittee to an independent contractor or agent for the purpose of reproducing, processing, reprocessing, or interpreting such data or information. When practicable, the Director shall notify the lessee(s) or permittee(s) who provided the data or information of the intent to disclose the data or information to an independent contractor or agent. The Director's notice of intent will afford the permittee(s) or lessee(s) a period of not less than 5 working days within which to comment on the intended action. When the Director so notifies a lessee or permittee of the intent to disclose data or information to an independent contractor or agent, all other owners of such data or information shall be deemed to have been notified of the Director's intent. Prior to any such disclosure, the contractor or agent shall be required to execute a written commitment not to disclose any data or information to anyone without the express consent of the Director, and not to make any disclosure or use of the data or information other than that provided in the contract. Contracts between the Minerals Management Service and independent contractors shall be available to the lessee(s) or permittee(s) for inspection. In the event of any unauthorized use or disclosure of data or information by the contractor or agent, or by an employee thereof, the responsible contractor or agent or employee thereof shall be liable for penalties pursuant to section 24 of the Act.

(e)(1) After delivery of data or information in accordance with paragraph (b)(1) of this section and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the lessee or permittee shall be reimbursed for the cost of reproducing the data or information at the lessee's or permittee's lowest rate or at the lowest commercial rate established in the area, whichever is less. Requests for reimbursement must be made within 60 days of the delivery date of the data or information requested under paragraph (b)(1) of this section.

(2) After delivery of data or information in accordance with paragraph (b)(3) of this section, and upon receipt of a request for reimbursement and a determination by the Director that the requested reimbursement is proper, the lessee or permittee shall be reimbursed for the cost of processing or reprocessing and of reproducing the requested data or information. Requests for reimbursement must be made within 60 days of the delivery date of the data or information and shall be for only the costs attributable to processing or reprocessing and reproducing, as distinguished from the costs of data acquisition.

(3) Requests for reimbursement are to contain a breakdown of costs in sufficient detail to allow separation of reproduction, processing, and reprocessing costs from acquisition and other costs.

(f) Each Federal Department or Agency shall provide the Director with any data which it has obtained pursuant to section 11 of the Act and any other information which may be necessary or useful to assist the Director in carrying out the provisions of the Act.

[44 FR 46408, Aug. 7, 1979, as amended at 51 FR 17176, May 9, 1986]

§ 252.4 Summary Report to affected States.

(a) The Director, as soon as practicable after analysis, interpretation, and compilation of oil and gas data and information developed by the Minerals Management Service or furnished by lessees, permittees, or other government agencies, shall make available to affected States and, upon request, to the executive of any affected local government, a Summary Report of data and information designed to assist them in planning for the onshore impacts of potential OCS oil and gas development and production. The Director shall consult with affected States and other interested parties to define the nature, scope, content, and timing of the Summary Report. The Director may consult with affected States and other interested parties regarding subsequent revisions in the definition of the nature, scope, content, and timing of the Summary Report. The Summary Report shall not contain data or information which the Director determines is exempt from disclosure in accordance with this part. The Summary Report shall not contain data or information the release of which the Director determines would unduly damage the competitive position of the lessee or permittee who provided the data or information which the Director has processed, analyzed, or interpreted during the development of the Summary Report. The Summary Report shall include:

(1) Estimates of oil and gas reserves; estimates of the oil and gas resources that may be found within areas which the Secretary has leased or plans to offer for lease; and when available, projected rates and volumes of oil and gas to be produced from leased areas;

(2) Magnitude of the approximate projections and timing of development, if and when oil or gas, or both, is discovered;

(3) Methods of transportation to be used, including vessels and pipelines and approximate location of routes to be followed; and

(4) General location and nature of near-shore and onshore facilities expected to be utilized.

(b) When the Director determines that significant changes have occurred in the information contained in a Summary Report, the Director shall prepare and make available the new or revised information to each affected State, and, upon request, to the executive of any affected local government.

§ 252.5 Information to be made available to affected States.

(a) The Director shall prepare an index of OCS information (see 30 CFR 256.10). The index shall list all relevant actual or proposed programs, plans, reports, environmental impact statements, nominations information, environmental study reports, lease sale information, and any similar type of relevant information, including modifications, comments, and revisions prepared or directly obtained by the Director under the Act. The index shall be sent to affected States and, upon request, to any affected local government. The public shall be informed of the availability of the index.

(b) Upon request, the Director shall transmit to affected States, affected local governments, and the public a copy of any information listed in the index which is subject to the control of the Minerals Management Service, in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and implementing regulations. The Director shall not transmit or make available any information which he determines is exempt from disclosure in accordance with this part.

[44 FR 46408, Aug. 7, 1979, as amended at 54 FR 50617, Dec. 8, 1989]

§ 252.6 Freedom of Information Act requirements.

(a) The Director shall make data and information available in accordance with the requirements and subject to

the limitations of the Freedom of Information Act (5 U.S.C. 552), the regulations contained in 43 CFR part 2 (Records and Testimony), the requirements of the Act, and the regulations contained in 30 CFR part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf) and 30 CFR part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf).

(b) Except as provided in §252.7 or in parts 250 and 251 of this chapter, no data or information determined by the director to be exempt from public disclosure under paragraph (a) of this section shall be provided to any affected State or be made available to the executive of any affected local government or to the public unless the lessee, or the permittee and all persons to whom such permittee has sold such data or information under promise of confidentiality, agree to such action.

§252.7 Privileged and proprietary data and information to be made available to affected States.

(a)(1) The Governor of any affected State may designate an appropriate State official to inspect, at a regional location which the Director shall designate, any privileged or proprietary data or information received by the Director regarding any activity in an area adjacent to such State, except that no such inspection shall take place prior to the sale of a lease covering the area in which such activity was conducted.

(2)(i) Except as provided for in 30 CFR 250.4 and 251.14, no privileged or proprietary data or information will be transmitted to any affected State unless the lessee who provided the privileged or proprietary data or information agrees in writing to the transmittal of the data or information.

(ii) Except as provided for in 30 CFR 250.4 and 251.14, no privileged or proprietary data or information will be transmitted to any affected State unless the permittee and all persons to whom the permittee has sold the data or information under promise of confidentiality agree in writing to the transmittal of the data or information.

(3) Knowledge obtained by a State official who inspects data or information under paragraph (a)(1) or who receives data or information under paragraph (a)(2) of this section shall be subject to the requirements and limitations of the Freedom of Information Act (5 U.S.C. 552), the regulations contained in 43 CFR part 2 (Records and Testimony), the Act (92 Stat. 629), the regulations contained in 30 CFR part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations contained in 30 CFR part 251 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in this part 252 (Outer Continental Shelf Oil and Gas Information Program).

(4) Prior to the transmittal of any privileged or proprietary data or information to any State, or the grant of access to a State official to such data or information, the Secretary shall enter into a written agreement with the Governor of the State in accordance with section 26(e) of the Act (43 U.S.C. 1352). In that agreement the State shall agree, as a condition precedent to receiving or being granted access to such data or information to: (i) Protect and maintain the confidentiality of privileged or proprietary data and information in accordance with the laws and regulations listed in paragraph (a)(3) of this section; (ii) waive the defenses as set forth in paragraph (b)(2) of this section; and (iii) hold the United States harmless from any violations of the agreement to protect the confidentiality of privileged or proprietary data or information by the State or its employees or contractors.

(b)(1) Whenever any employee of the Federal Government or of any State reveals in violation of the Act or of the provisions of the regulations implementing the Act, privileged or proprietary data or information obtained pursuant to the regulations in this chapter, the lessee or permittee who supplied such information to the Director or any other Federal official, and any person to whom such lessee or permittee has sold such data or information under the promise of confidentiality, may commence a civil action for damages in the appropriate district court of the United States against the Federal Government or such State, as the case may be. Any Federal or State

employee who is found guilty of failure to comply with any of the requirements of this section shall be subject to the penalties described in section 24 of the Act (43 U.S.C. 1350).

(2) In any action commenced against the Federal Government or a State pursuant to paragraph (b)(1) of this section, the Federal Government or such State, as the case may be, may not raise as a defense any claim of sovereign immunity, or any claim that the employee who revealed the privileged or proprietary data or information which is the basis of such suit was acting outside the scope of the person's employment in revealing such data or information.

(c) If the Director finds that any State cannot or does not comply with the conditions described in the agreement entered into pursuant to paragraph (a)(4) of this section, the Director shall thereafter withhold transmittal and deny access for inspection of privileged or proprietary data or information to such State until the Director finds that such State can and will comply with those conditions.

PART 254—OIL-SPILL RESPONSE REQUIREMENTS FOR FACILITIES LOCATED SEAWARD OF THE COAST LINE

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AUTHORITY: 33 U.S.C. 1321

SOURCE: 62 FR 13996, Mar. 25, 1997, unless otherwise noted.

Subpart A—General

§ 254.1 Who must submit a spill-response plan?

(a) If you are the owner or operator of an oil handling, storage, or transportation facility, and it is located seaward of the coast line, you must submit a spill-response plan to MMS for

approval. Your spill-response plan must demonstrate that you can respond quickly and effectively whenever oil is discharged from your facility. Refer to §254.6 for the definitions of ''oil,'' ''facility,'' and ''coast line'' if you have any doubts about whether to submit a plan.

(b) You must maintain a current response plan for an abandoned facility until you physically remove or dismantle the facility or until the Regional Supervisor notifies you in writing that a plan is no longer required.

(c) Owners or operators of offshore pipelines carrying essentially dry gas do not need to submit a plan. You must, however, submit a plan for a pipeline that carries:

(1) Oil;

(2) Condensate that has been injected into the pipeline; or

(3) Gas and naturally occurring condensate.

(d) If you are in doubt as to whether you must submit a plan for an offshore facility or pipeline, you should check with the Regional Supervisor.

(e) If your facility is located landward of the coast line, but you believe your facility is sufficiently similar to OCS facilities that it should be regulated by MMS, you may contact the Regional Supervisor, offer to accept MMS jurisdiction over your facility, and request that MMS seek from the agency with jurisdiction over your facility a relinquishment of that jurisdiction.

§254.2 When must I submit a response plan?

(a) You must submit, and MMS must approve, a response plan that covers each facility located seaward of the coast line before you may use that facility. To continue operations, you must operate the facility in compliance with the plan.

(b) Despite the provisions of paragraph (a) of this section, you may operate your facility after you submit your plan while MMS reviews it for approval. To operate a facility without an approved plan, you must certify in writing to the Regional Supervisor that you have the capability to respond, to the maximum extent practicable, to a worst case discharge or a substantial threat of such a discharge. The certification must show that you have ensured by contract, or other means approved by the Regional Supervisor, the availability of private personnel and equipment necessary to respond to the discharge. Verification from the organization(s) providing the personnel and equipment must accompany the certification. MMS will not allow you to operate a facility for more than 2 years without an approved plan.

(c) If you have a plan that MMS already approved, you are not required to immediately rewrite the plan to comply with this part. You must, however, submit the information this regulation requires when submitting your first plan revision (see §254.30) after the effective date of this rule. The Regional Supervisor may extend this deadline upon request.

§254.3 May I cover more than one facility in my response plan?

(a) Your response plan may be for a single lease or facility or a group of leases or facilities. All the leases or facilities in your plan must have the same owner or operator (including affiliates) and must be located in the same MMS Region (see definition of Regional Response Plan in §254.6).

(b) Regional Response Plans must address all the elements required for a response plan in Subpart B, *Oil Spill Response Plans for Outer Continental Shelf Facilities,* or Subpart D, *Oil Spill Response Requirements for Facilities Located in State Waters Seaward of the Coast Line,* as appropriate.

(c) When developing a Regional Response Plan, you may group leases or facilities subject to the approval of the Regional Supervisor for the purposes of:

(1) Calculating response times;

(2) Determining quantities of response equipment;

(3) Conducting oil-spill trajectory analyses;

(4) Determining worst case discharge scenarios; and

(5) Identifying areas of special economic and environmental importance that may be impacted and the strategies for their protection.

(d) The Regional Supervisor may specify how to address the elements of

a Regional Response Plan. The Regional Supervisor also may require that Regional Response Plans contain additional information if necessary for compliance with appropriate laws and regulations.

§ 254.4 May I reference other documents in my response plan?

You may reference information contained in other readily accessible documents in your response plan. Examples of documents that you may reference are the National Contingency Plan (NCP), Area Contingency Plan (ACP), MMS environmental documents, and Oil Spill Removal Organization (OSRO) documents that are readily accessible to the Regional Supervisor. You must ensure that the Regional Supervisor possesses or is provided with copies of all OSRO documents you reference. You should contact the Regional Supervisor if you want to know whether a reference is acceptable.

§ 254.5 General response plan requirements.

(a) The response plan must provide for response to an oil spill from the facility. You must immediately carry out the provisions of the plan whenever there is a release of oil from the facility. You must also carry out the training, equipment testing, and periodic drills described in the plan, and these measures must be sufficient to ensure the safety of the facility and to mitigate or prevent a discharge or a substantial threat of a discharge.

(b) The plan must be consistent with the National Contingency Plan and the appropriate Area Contingency Plan(s).

(c) Nothing in this part relieves you from taking all appropriate actions necessary to immediately abate the source of a spill and remove any spills of oil.

(d) In addition to the requirements listed in this part, you must provide any other information the Regional Supervisor requires for compliance with appropriate laws and regulations.

§ 254.6 Definitions.

For the purposes of this part:

Adverse weather conditions means weather conditions found in the operating area that make it difficult for response equipment and personnel to clean up or remove spilled oil or hazardous substances. These include, but are not limited to: Fog, inhospitable water and air temperatures, wind, sea ice, current, and sea states. It does not refer to conditions such as a hurricane, under which it would be dangerous or impossible to respond to a spill.

Area Contingency Plan means an Area Contingency Plan prepared and published under section 311(j) of the Federal Water Pollution Control Act (FWPCA).

Coast line means the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters.

Discharge means any emission (other than natural seepage), intentional or unintentional, and includes, but is not limited to, spilling, leaking, pumping, pouring, emitting, emptying, or dumping.

District Supervisor means the MMS officer with authority and responsibility for a district within an MMS Region.

Facility means any structure, group of structures, equipment, or device (other than a vessel) which is used for one or more of the following purposes: Exploring for, drilling for, producing, storing, handling, transferring, processing, or transporting oil. The term excludes deep-water ports and their associated pipelines as defined by the Deepwater Port Act of 1974, but includes other pipelines used for one or more of these purposes. A mobile offshore drilling unit is classified as a facility when engaged in drilling or downhole operations.

Maximum extent practicable means within the limitations of available technology, as well as the physical limitations of personnel, when responding to a worst case discharge in adverse weather conditions.

National Contingency Plan means the National Oil and Hazardous Substances Pollution Contingency Plan prepared and published under section 311(d) of the FWPCA, (33 U.S.C. 1321(d)) or revised under section 105 of the Comprehensive Environmental Response Compensation and Liability Act (42 U.S.C. 9605).

National Contingency Plan Product Schedule means a schedule of dispersants and other chemical or biological products, maintained by the Environmental Protection Agency, that may be authorized for use on oil discharges in accordance with the procedures found at 40 CFR 300.910.

Oil means oil of any kind or in any form, including but not limited to petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil. This also includes hydrocarbons produced at the wellhead in liquid form (includes distillates or condensate associated with produced natural gas), and condensate that has been separated from a gas prior to injection into a pipeline. It does not include petroleum, including crude oil or any fraction thereof, which is specifically listed or designated as a hazardous substance under paragraphs (A) through (F) of section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (42 U. S. C. 9601) and which is subject to the provisions of that Act. It also does not include animal fats and oils and greases and fish and marine mammal oils, within the meaning of paragraph (2) of section 61(a) of title 13, United States Code, and oils of vegetable origin, including oils from the seeds, nuts, and kernels referred to in paragraph (1)(A) of that section.

Oil spill removal organization (OSRO) means an entity contracted by an owner or operator to provide spill-response equipment and/or manpower in the event of an oil or hazardous substance spill.

Outer Continental Shelf means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Owner or operator means, in the case of an offshore facility, any person owning or operating such offshore facility. In the case of any abandoned offshore facility, it means the person who owned such facility immediately prior to such abandonment.

Pipeline means pipe and any associated equipment, appurtenance, or building used or intended for use in the transportation of oil located seaward of the coast line, except those used for deep-water ports. Pipelines do not include vessels such as barges or shuttle tankers used to transport oil from facilities located seaward of the coast line.

Qualified individual means an English-speaking representative of an owner or operator, located in the United States, available on a 24-hour basis, with full authority to obligate funds, carry out removal actions, and communicate with the appropriate Federal officials and the persons providing personnel and equipment in removal operations.

Regional Response Plan means a spill-response plan required by this part which covers multiple facilities or leases of an owner or operator, including affiliates, which are located in the same MMS Region.

Regional Supervisor means the MMS official with responsibility and authority for operations or other designated program functions within an MMS Region.

Remove means containment and cleanup of oil from water and shorelines or the taking of other actions as may be necessary to minimize or mitigate damage to the public health or welfare, including, but not limited to, fish, shellfish, wildlife, public and private property, shorelines, and beaches.

Spill is synonymous with ''discharge'' for the purposes of this part.

Spill management team means the trained persons identified in a response plan who staff the organizational structure to manage spill response.

Spill-response coordinator means a trained person charged with the responsibility and designated the commensurate authority for directing and coordinating response operations.

Spill-response operating team means the trained persons who respond to spills through deployment and operation of oil-spill response equipment.

State waters located seaward of the coast line means the belt of the seas measured from the coast line and extending seaward a distance of 3 miles (except the coast of Texas and the Gulf

coast of Florida, where the State waters extend seaward a distance of 3 leagues).

You means the owner or the operator as defined in this section.

§ 254.7 How do I submit my response plan to the MMS?

You must submit the number of copies of your response plan that the appropriate MMS regional office requires. If you prefer to use improved information technology such as electronic filing to submit your plan, ask the Regional Supervisor for further guidance.

(a) Send plans for facilities located seaward of the coast line of Alaska to: Minerals Management Service, Regional Supervisor, Field Operations, Alaska OCS Region, 949 East 36th Avenue, Anchorage, AK 99508–4302.

(b) Send plans for facilities in the Gulf of Mexico or Atlantic Ocean to: Minerals Management Service, Regional Supervisor, Field Operations, Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard, New Orleans, LA 70123–2394.

(c) Send plans for facilities in the Pacific Ocean (except seaward of the coast line of Alaska) to: Minerals Management Service, Regional Supervisor, Office of Development Operations and Safety, Pacific OCS Region, 770 Paseo Camarillo, Camarillo, CA 93010–6064.

§ 254.8 May I appeal decisions under this rule?

You may appeal orders or decisions issued under the regulations in this part pursuant to part 290 of this title. If you file an appeal with the Director, it does not suspend the requirement for you to comply with an order or decision other than one that requires the payment of a civil penalty. Compliance also is not suspended pending an appeal to the Interior Board of Land Appeals under 43 CFR part 4.

§ 254.9 Authority for information collection.

(a) The Office of Management and Budget (OMB) has approved the information collection requirements in this part under 44 U.S.C. 3501 *et seq.* OMB assigned the control number 1010–0091. The title of this information collection is ''30 CFR Part 254, Oil Spill Response Requirements for Facilities Located Seaward of the Coast line.''

(b) MMS collects this information to ensure that the owner or operator of an offshore facility is prepared to respond to an oil spill. MMS uses the information to verify compliance with the mandates of the Oil Pollution Act of 1990 (OPA). The requirement to submit this information is mandatory. No confidential or proprietary information is collected.

(c) 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.

(d) Send comments regarding any aspect of the collection of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Minerals Management Service, Mail Stop 4230, Department of the Interior, 1849 C Streets, NW, Washington, DC 20240; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for the Department of the Interior (1010–0091), 725 17th Street, NW, Washington, DC 20503.

[62 FR 13996, Mar. 25, 1997, as amended at 62 FR 18041, Apr. 14, 1997]

Subpart B—Oil-Spill Response Plans for Outer Continental Shelf Facilities

§ 254.20 Purpose.

This subpart describes the requirements for preparing spill-response plans for facilities located on the OCS.

§ 254.21 How must I format my response plan?

(a) You must divide your response plan for OCS facilities into the sections specified in paragraph (b) and explained in the other sections of this subpart. The plan must have an easily found marker identifying each section. You may use an alternate format if you include a cross-reference table to identify the location of required sections. You may use alternate contents if you can demonstrate to the Regional Supervisor that they provide for equal or greater levels of preparedness.

(b) Your plan must include:
(1) Introduction and plan contents.
(2) Emergency response action plan.
(3) Appendices:
(i) Equipment inventory.
(ii) Contractual agreements.
(iii) Worst case discharge scenario.
(iv) Dispersant use plan.
(v) In situ burning plan.
(vi) Training and drills.

§254.22 What information must I include in the "Introduction and plan contents" section?

The ''Introduction and plan contents'' section must provide:

(a) Identification of the facility the plan covers, including its location and type;

(b) A table of contents;

(c) A record of changes made to the plan; and

(d) A cross-reference table, if needed, because you are using an alternate format for your plan.

§254.23 What information must I include in the "Emergency response action plan" section?

The ''Emergency response action plan''section is the core of the response plan. Put information in easy-to-use formats such as flow charts or tables where appropriate. This section must include:

(a) Designation, by name or position, of a trained qualified individual (QI) who has full authority to implement removal actions and ensure immediate notification of appropriate Federal officials and response personnel.

(b) Designation, by name or position, of a trained spill management team available on a 24-hour basis. The team must include a trained spill-response coordinator and alternate(s) who have the responsibility and authority to direct and coordinate response operations on your behalf. You must describe the team's organizational structure as well as the responsibilities and authorities of each position on the spill management team.

(c) Description of a spill-response operating team. Team members must be trained and available on a 24-hour basis to deploy and operate spill-response equipment. They must be able to respond within a reasonable minimum specified time. You must include the number and types of personnel available from each identified labor source.

(d) A planned location for a spill-response operations center and provisions for primary and alternate communications systems available for use in coordinating and directing spill-response operations. You must provide telephone numbers for the response operations center. You also must provide any facsimile numbers and primary and secondary radio frequencies that will be used.

(e) A listing of the types and characteristics of the oil handled, stored, or transported at the facility.

(f) Procedures for the early detection of a spill.

(g) Identification of procedures you will follow in the event of a spill or a substantial threat of a spill. The procedures should show appropriate response levels for differing spill sizes including those resulting from a fire or explosion. These will include, as appropriate:

(1) Your procedures for spill notification. The plan must provide for the use of the oil spill reporting forms included in the Area Contingency Plan or an equivalent reporting form.

(i) Your procedures must include a current list which identifies the following by name or position, corporate address, and telephone number (including facsimile number if applicable):

(A) The qualified individual;

(B) The spill-response coordinator and alternate(s); and

(C) Other spill-response management team members.

(ii) You must also provide names, telephone numbers, and addresses for the following:

(A) OSRO's that the plan cites;

(B) Federal, State, and local regulatory agencies that you must consult to obtain site specific environmental information; and

(C) Federal, State, and local regulatory agencies that you must notify when an oil spill occurs.

(2) Your methods to monitor and predict spill movement;

(3) Your methods to identify and prioritize the beaches, waterfowl, other marine and shoreline resources, and areas of special economic and environmental importance;

(4) Your methods to protect beaches, waterfowl, other marine and shoreline resources, and areas of special economic or environmental importance;

(5) Your methods to ensure that containment and recovery equipment as well as the response personnel are mobilized and deployed at the spill site;

(6) Your methods to ensure that devices for the storage of recovered oil are sufficient to allow containment and recovery operations to continue without interruption;

(7) Your procedures to remove oil and oiled debris from shallow waters and along shorelines and rehabilitating waterfowl which become oiled;

(8) Your procedures to store, transfer, and dispose of recovered oil and oil-contaminated materials and to ensure that all disposal is in accordance with Federal, State, and local requirements; and

(9) Your methods to implement your dispersant use plan and your in situ burning plan.

§ 254.24 What information must I include in the "Equipment inventory" appendix?

Your ''Equipment inventory appendix'' must include:

(a) An inventory of spill-response materials and supplies, services, equipment, and response vessels available locally and regionally. You must identify each supplier and provide their locations and telephone numbers.

(b) A description of the procedures for inspecting and maintaining spill-response equipment in accordance with § 254.43.

§ 254.25 What information must I include in the "Contractual agreements" appendix?

Your ''Contractual agreements'' appendix must furnish proof of any contracts or membership agreements with OSRO's, cooperatives, spill-response service providers, or spill management team members who are not your employees that you cite in the plan. To provide this proof, submit copies of the contracts or membership agreements or certify that contracts or membership agreements are in effect. The contract or membership agreement must include provisions for ensuring the availability of the personnel and/or equipment on a 24-hour-per-day basis.

§ 254.26 What information must I include in the "Worst case discharge scenario" appendix?

The discussion of your worst case discharge scenario must include all of the following elements:

(a) The volume of your worst case discharge scenario determined using the criteria in § 254.47. Provide any assumptions made and the supporting calculations used to determine this volume.

(b) An appropriate trajectory analysis specific to the area in which the facility is located. The analysis must identify onshore and offshore areas that a discharge potentially could affect. The trajectory analysis chosen must reflect the maximum distance from the facility that oil could move in a time period that it reasonably could be expected to persist in the environment.

(c) A list of the resources of special economic or environmental importance that potentially could be impacted in the areas identified by your trajectory analysis. You also must state the strategies that you will use for their protection. At a minimum, this list must include those resources of special economic and environmental importance, if any, specified in the appropriate Area Contingency Plan(s).

(d) A discussion of your response to your worst case discharge scenario in adverse weather conditions. This discussion must include:

(1) A description of the response equipment that you will use to contain and recover the discharge to the maximum extent practicable. This description must include the types, location(s) and owner, quantity, and capabilities of the equipment. You also must include the effective daily recovery capacities, where applicable. You must calculate the effective daily recovery capacities using the methods described in § 254.44. For operations at a drilling or production facility, your scenario must show how you will cope with the initial spill volume upon arrival at the scene and then support operations for a blowout lasting 30 days.

(2) A description of the personnel, materials, and support vessels that would be necessary to ensure that the identified response equipment is deployed and operated promptly and effectively. Your description must include the location and owner of these resources as well as the quantities and types (if applicable);

(3) A description of your oil storage, transfer, and disposal equipment. Your description must include the types, location and owner, quantity, and capacities of the equipment; and

(4) An estimation of the individual times needed for:

(i) Procurement of the identified containment, recovery, and storage equipment;

(ii) Procurement of equipment transportation vessel(s);

(iii) Procurement of personnel to load and operate the equipment;

(iv) Equipment loadout (transfer of equipment to transportation vessel(s));

(v) Travel to the deployment site (including any time required for travel from an equipment storage area); and

(vi) Equipment deployment.

(e) In preparing the discussion required by paragraph (d) of this section, you must:

(1) Ensure that the response equipment, materials, support vessels, and strategies listed are suitable, within the limits of current technology, for the range of environmental conditions anticipated at your facility; and

(2) Use standardized, defined terms to describe the range of environmental conditions anticipated and the capabilities of response equipment. Examples of acceptable terms include those defined in American Society for Testing of Materials (ASTM) publication F625–94, *Standard Practice for Describing Environmental Conditions Relevant to Spill Control Systems for Use on Water,* and ASTM F818–93, *Standard Definitions Relating to Spill Response Barriers.*

§ 254.27 What information must I include in the "Dispersant use plan" appendix?

Your dispersant use plan must be consistent with the National Contingency Plan Product Schedule and other provisions of the National Contingency Plan and the appropriate Area Contingency Plan(s). The plan must include:

(a) An inventory and a location of the dispersants and other chemical or biological products which you might use on the oils handled, stored, or transported at the facility;

(b) A summary of toxicity data for these products;

(c) A description and a location of any application equipment required as well as an estimate of the time to commence application after approval is obtained;

(d) A discussion of the application procedures;

(e) A discussion of the conditions under which product use may be requested; and

(f) An outline of the procedures you must follow in obtaining approval for product use.

§ 254.28 What information must I include in the "In situ burning plan" appendix?

Your in situ burning plan must be consistent with any guidelines authorized by the National Contingency Plan and the appropriate Area Contingency Plan(s). Your in situ burning plan must include:

(a) A description of the in situ burn equipment including its availability, location, and owner;

(b) A discussion of your in situ burning procedures, including provisions for ignition of an oil spill;

(c) A discussion of environmental effects of an in situ burn;

(d) Your guidelines for well control and safety of personnel and property;

(e) A discussion of the circumstances in which in situ burning may be appropriate;

(f) Your guidelines for making the decision to ignite; and

(g) An outline of the procedures you must follow to obtain approval for an in situ burn.

§ 254.29 What information must I include in the "Training and drills" appendix?

Your ''Training and drills'' appendix must:

(a) Identify and include the dates of the training provided to members of the spill-response management team and the qualified individual. The types

of training given to the members of the spill-response operating team also must be described. The training requirements for your spill management team and your spill-response operating team are specified in § 254.41. You must designate a location where you keep course completion certificates or attendance records for this training.

(b) Describe in detail your plans for satisfying the exercise requirements of § 254.42. You must designate a location where you keep the records of these exercises.

§ 254.30 When must I revise my response plan?

(a) You must review your response plan at least every 2 years and submit all resulting modifications to the Regional Supervisor. If this review does not result in modifications, you must inform the Regional Supervisor in writing that there are no changes.

(b) You must submit revisions to your plan for approval within 15 days whenever:

(1) A change occurs which significantly reduces your response capabilities;

(2) A significant change occurs in the worst case discharge scenario or in the type of oil being handled, stored, or transported at the facility;

(3) There is a change in the name(s) or capabilities of the oil spill removal organizations cited in the plan; or

(4) There is a significant change to the Area Contingency Plan(s).

(c) The Regional Supervisor may require that you resubmit your plan if the plan has become outdated or if numerous revisions have made its use difficult.

(d) The Regional Supervisor will periodically review the equipment inventories of OSRO's to ensure that sufficient spill removal equipment is available to meet the cumulative needs of the owners and operators who cite these organizations in their plans.

(e) The Regional Supervisor may require you to revise your plan if significant inadequacies are indicated by:

(1) Periodic reviews (described in paragraph (d) of this section);

(2) Information obtained during drills or actual spill responses; or

(3) Other relevant information the Regional Supervisor obtained.

Subpart C—Related Requirements for Outer Continental Shelf Facilities

§ 254.40 Records.

You must make all records of services, personnel, and equipment provided by OSRO's or cooperatives available to any authorized MMS representative upon request.

§ 254.41 Training your response personnel.

(a) You must ensure that the members of your spill-response operating team who are responsible for operating response equipment attend hands-on training classes at least annually. This training must include the deployment and operation of the response equipment they will use. Those responsible for supervising the team must be trained annually in directing the deployment and use of the response equipment.

(b) You must ensure that the spill-response management team, including the spill-response coordinator and alternates, receives annual training. This training must include instruction on:

(1) Locations, intended use, deployment strategies, and the operational and logistical requirements of response equipment;

(2) Spill reporting procedures;

(3) Oil-spill trajectory analysis and predicting spill movement; and

(4) Any other responsibilities the spill management team may have.

(c) You must ensure that the qualified individual is sufficiently trained to perform his or her duties.

(d) You must keep all training certificates and training attendance records at the location designated in your response plan for at least 2 years. They must be made available to any authorized MMS representative upon request.

§ 254.42 Exercises for your response personnel and equipment.

(a) You must exercise your entire response plan at least once every 3 years (triennial exercise). You may satisfy

this requirement by conducting separate exercises for individual parts of the plan over the 3-year period; you do not have to exercise your entire response plan at one time.

(b) In satisfying the triennial exercise requirement, you must, at a minimum, conduct:

(1) An annual spill management team tabletop exercise. The exercise must test the spill management team's organization, communication, and decision-making in managing a response. You must not reveal the spill scenario to team members before the exercise starts.

(2) An annual deployment exercise of response equipment identified in your plan that is staged at onshore locations. You must deploy and operate each type of equipment in each triennial period. However, it is not necessary to deploy and operate each individual piece of equipment.

(3) An annual notification exercise for each facility that is manned on a 24- hour basis. The exercise must test the ability of facility personnel to communicate pertinent information in a timely manner to the qualified individual.

(4) A semiannual deployment exercise of any response equipment which the MMS Regional Supervisor requires an owner or operator to maintain at the facility or on dedicated vessels. You must deploy and operate each type of this equipment at least once each year. Each type need not be deployed and operated at each exercise.

(c) During your exercises, you must simulate conditions in the area of operations, including seasonal weather variations, to the extent practicable. The exercises must cover a range of scenarios over the 3-year exercise period, simulating responses to large continuous spills, spills of short duration and limited volume, and your worst case discharge scenario.

(d) MMS will recognize and give credit for any documented exercise conducted that satisfies some part of the required triennial exercise. You will receive this credit whether the owner or operator, an OSRO, or a Government regulatory agency initiates the exercise. MMS will give you credit for an actual spill response if you evaluate the response and generate a proper record. Exercise documentation should include the following information:

(1) Type of exercise;

(2) Date and time of the exercise;

(3) Description of the exercise;

(4) Objectives met; and

(5) Lessons learned.

(e) All records of spill-response exercises must be maintained for the complete 3-year exercise cycle. Records should be maintained at the facility or at a corporate location designated in the plan. Records showing that OSRO's and oil spill removal cooperatives have deployed each type of equipment also must be maintained for the 3-year cycle.

(f) You must inform the Regional Supervisor of the date of any exercise required by paragraph (b)(1), (2), or (4) of this section at least 30 days before the exercise. This will allow MMS personnel the opportunity to witness any exercises.

(g) The Regional Supervisor periodically will initiate unannounced drills to test the spill response preparedness of owners and operators.

(h) The Regional Supervisor may require changes in the frequency or location of the required exercises, equipment to be deployed and operated, or deployment procedures or strategies. The Regional Supervisor may evaluate the results of the exercises and advise the owner or operator of any needed changes in response equipment, procedures, or strategies.

(i) Compliance with the National Preparedness for Response Exercise Program (PREP) Guidelines will satisfy the exercise requirements of this section. Copies of the PREP document may be obtained from the Regional Supervisor.

§254.43 Maintenance and periodic inspection of response equipment.

(a) You must ensure that the response equipment listed in your response plan is inspected at least monthly and is maintained, as necessary, to ensure optimal performance.

(b) You must ensure that records of the inspections and the maintenance activities are kept for at least 2 years and are made available to any authorized MMS representative upon request.

§ 254.44 Calculating response equipment effective daily recovery capacities.

(a) You are required by § 254.26(d)(1) to calculate the effective daily recovery capacity of the response equipment identified in your response plan that you would use to contain and recover your worst case discharge. You must calculate the effective daily recovery capacity of the equipment by multiplying the manufacturer's rated throughput capacity over a 24-hour period by 20 percent. This 20 percent efficiency factor takes into account the limitations of the recovery operations due to available daylight, sea state, temperature, viscosity, and emulsification of the oil being recovered. You must use this calculated rate to determine if you have sufficient recovery capacity to respond to your worst case discharge scenario.

(b) If you want to use a different efficiency factor for specific oil recovery devices, you must submit evidence to substantiate that efficiency factor. Adequate evidence includes verified performance data measured during actual spills or test data gathered according to the provisions of § 254.45 (b) and (c).

§ 254.45 Verifying the capabilities of your response equipment.

(a) The Regional Supervisor may require performance testing of any spill-response equipment listed in your response plan to verify its capabilities if the equipment:

(1) Has been modified;

(2) Has been damaged and repaired; or

(3) Has a claimed effective daily recovery capacity that is inconsistent with data otherwise available to MMS.

(b) You must conduct any required performance testing of booms in accordance with MMS-approved test criteria. You may use the document ''Test Protocol for the Evaluation of Oil-Spill Containment Booms,'' available from MMS, for guidance. Performance testing of skimmers also must be conducted in accordance with MMS approved test criteria. You may use the document ''Suggested Test Protocol for the Evaluation of Oil Spill Skimmers for the OCS,'' available from MMS, for guidance.

(c) You are responsible for any required testing of equipment performance and for the accuracy of the information submitted.

§ 254.46 Whom do I notify if an oil spill occurs?

(a) You must immediately notify the National Response Center (1–800–424–8802) if you observe:

(1) An oil spill from your facility;

(2) An oil spill from another offshore facility; or

(3) An offshore spill of unknown origin.

(b) In the event of a spill of 1 barrel or more from your facility, you must orally notify the Regional Supervisor without delay. You also must report spills from your facility of unknown size but thought to be 1 barrel or more.

(1) If a spill from your facility not originally reported to the Regional Supervisor is subsequently found to be 1 barrel or more, you must then report it without delay.

(2) You must file a written followup report for any spill from your facility of 1 barrel or more. The Regional Supervisor must receive this confirmation within 15 days after the spillage has been stopped. All reports must include the cause, location, volume, and remedial action taken. Reports of spills of more than 50 barrels must include information on the sea state, meteorological conditions, and the size and appearance of the slick. The Regional Supervisor may require additional information if it is determined that an analysis of the response is necessary.

(c) If you observe a spill resulting from operations at another offshore facility, you must immediately notify the responsible party and the Regional Supervisor.

§ 254.47 Determining the volume of oil of your worst case discharge scenario.

You must calculate the volume of oil of your worst case discharge scenario as follows:

(a) For an oil production platform facility, the size of your worst case discharge scenario is the sum of the following:

(1) The maximum capacity of all oil storage tanks and flow lines on the facility. Flow line volume may be estimated; and

(2) The volume of oil calculated to leak from a break in any pipelines connected to the facility considering shutdown time, the effect of hydrostatic pressure, gravity, frictional wall forces and other factors; and

(3) The daily production volume from an uncontrolled blowout of the highest capacity well associated with the facility. In determining the daily discharge rate, you must consider reservoir characteristics, casing/production tubing sizes, and historical production and reservoir pressure data. Your scenario must discuss how to respond to this well flowing for 30 days as required by §254.26(d)(1).

(b) For exploratory or development drilling operations, the size of your worst case discharge scenario is the daily volume possible from an uncontrolled blowout. In determining the daily discharge rate, you must consider any known reservoir characteristics. If reservoir characteristics are unknown, you must consider the characteristics of any analog reservoirs from the area and give an explanation for the selection of the reservoir(s) used. Your scenario must discuss how to respond to this well flowing for 30 days as required by §254.26(d)(1).

(c) For a pipeline facility, the size of your worst case discharge scenario is the volume possible from a pipeline break. You must calculate this volume as follows:

(1) Add the pipeline system leak detection time to the shutdown response time.

(2) Multiply the time calculated in paragraph (c)(1) of this section by the highest measured oil flow rate over the preceding 12-month period. For new pipelines, you should use the predicted oil flow rate in the calculation.

(3) Add to the volume calculated in paragraph (c)(2) of this section the total volume of oil that would leak from the pipeline after it is shut in. Calculate this volume by taking into account the effects of hydrostatic pressure, gravity, frictional wall forces, length of pipeline segment, tie-ins with other pipelines, and other factors.

(d) If your facility which stores, handles, transfers, processes, or transports oil does not fall into the categories listed in paragraph (a), (b), or (c) of this section, contact the Regional Supervisor for instructions on the calculation of the volume of your worst case discharge scenario.

Subpart D—Oil-Spill Response Requirements for Facilities Located in State Waters Seaward of the Coast Line.

§254.50 Spill response plans for facilities located in State waters seaward of the coast line.

Owners or operators of facilities located in State waters seaward of the coast line must submit a spill-response plan to MMS for approval. You may choose one of three methods to comply with this requirement. The three methods are described in §§254.51, 254.52, and 254.53.

§254.51 Modifying an existing OCS response plan.

You may modify an existing response plan covering a lease or facility on the OCS to include a lease or facility in State waters located seaward of the coast line. Since this plan would cover more than one lease or facility, it would be considered a Regional Response Plan. You should refer to §254.3 and contact the appropriate regional MMS office if you have any questions on how to prepare this Regional Response Plan.

§254.52 Following the format for an OCS response plan.

You may develop a response plan following the requirements for plans for OCS facilities found in subpart B of this part.

§254.53 Submitting a response plan developed under State requirements.

(a) You may submit a response plan to MMS for approval that you developed in accordance with the laws or regulations of the appropriate State. The plan must contain all the elements the State and OPA require and must:

(1) Be consistent with the requirements of the National Contingency

Plan and appropriate Area Contingency Plan(s).

(2) Identify a qualified individual and require immediate communication between that person and appropriate Federal officials and response personnel if there is a spill.

(3) Identify any private personnel and equipment necessary to remove, to the maximum extent practicable, a worst case discharge as defined in § 254.47. The plan must provide proof of contractual services or other evidence of a contractual agreement with any OSRO's or spill management team members who are not employees of the owner or operator.

(4) Describe the training, equipment testing, periodic unannounced drills, and response actions of personnel at the facility. These must ensure both the safety of the facility and the mitigation or prevention of a discharge or the substantial threat of a discharge.

(5) Describe the procedures you will use to periodically update and resubmit the plan for approval of each significant change.

(b) Your plan developed under State requirements also must include the following information:

(1) A list of the facilities and leases the plan covers and a map showing their location;

(2) A list of the types of oil handled, stored, or transported at the facility;

(3) Name and address of the State agency to whom the plan was submitted;

(4) Date you submitted the plan to the State;

(5) If the plan received formal approval, the name of the approving organization, the date of approval, and a copy of the State agency's approval letter if one was issued; and

(6) Identification of any regulations or standards used in preparing the plan.

§ 254.54 Spill prevention for facilities located in State waters seaward of the coast line.

In addition to your response plan, you must submit to the Regional Supervisor a description of the steps you are taking to prevent spills of oil or mitigate a substantial threat of such a discharge. You must identify all State or Federal safety or pollution prevention requirements that apply to the prevention of oil spills from your facility, and demonstrate your compliance with these requirements. You also should include a description of industry safety and pollution prevention standards your facility meets. The Regional Supervisor may prescribe additional equipment or procedures for spill prevention if it is determined that your efforts to prevent spills do not reflect good industry practices.

PART 256—LEASING OF SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF

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APPENDIX A TO PART 256—OIL AND GAS CASH BONUS BID

AUTHORITY: 43 U.S.C. 1331 *et seq.*

SOURCE: 44 FR 38276, June 29, 1979, unless otherwise noted. Redesignated at 47 FR 47006, Oct. 22, 1982.

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

§256.0 Authority for information collection.

The collections of information contained in part 256 have been approved by the Office of Management and Budget under 44 U.S.C. 3501 et seq. and assigned OMB control number 1010–0006. The information will be used to determine if the applicant filing for a lease on the Outer Continental Shelf (OCS) is qualified to hold such a lease. Response is required to obtain a benefit in accordance with 43 U.S.C. 1331 et seq. Public reporting burden for this information is estimated to average 1.8 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to the Information Collection Clearance Officer; Minerals Management Service, Mail Stop 2300; 381 Elden Street; Herndon, Virginia 22070–4817, and the Office of Management and Budget; Paperwork Reduction Project 1010–0006; Washington, DC 20503.

[58 FR 45261, Aug. 27, 1993]

§256.1 Purpose.

The purpose of these regulations is to establish the procedures under which the Secretary of the Interior will exercise the authority granted to administer a leasing program for minerals and grant rights-of-way on the submerged lands of the Outer Continental Shelf.

§256.2 Policy.

The management of Outer Continental Shelf resources is to be conducted

in accordance with the findings, purposes and policy directions provided by the Outer Continental Shelf Lands Act Amendments of 1978 (43 U.S.C. 1332, 1801, 1802), and other Executive, legislative, judicial and Departmental guidance. The Secretary of the Interior shall consider available environmental information in making decisions affecting Outer Continental Shelf resources.

§ 256.4 Authority.

The Outer Continental Shelf Lands Act as amended, (43 U.S.C. 1331 et seq.) authorizes the Secretary of the Interior to issue, on a competitive basis, leases for oil and gas, and sulphur, in submerged lands of the Outer Continental Shelf. The act authorizes the Secretary of the Interior to grant rights-of-way through the submerged lands of the Outer Continental Shelf. The Energy Policy and Conservation Act of 1975 (42 U.S.C. 6213), prohibits joint bidding by major oil and gas producers.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982 and amended at 54 FR 2049, Jan. 18, 1989]

§ 256.5 Definitions.

As used in this part, the term:

(a) *Act* refers to the Outer Continental Shelf Lands Act of August 7, 1953 (43 U.S.C. 1331 et seq.) as amended.

(b) *Director* means the Director, Minerals Management Service.

(c) *OCS* means the Outer Continental Shelf, as that term is defined in 43 U.S.C. 1331(a).

(d) *Secretary* means the Secretary of the Interior or an official authorized to act on the Secretary's behalf.

(e) *MMS* means the Minerals Management Service.

(f) *Coastal zone* means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal States, and includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches, which zone extends seaward to the outer limit of the United States territorial sea and extends inland from the shore lines to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority of section 305(b)(1) of the Coastal Zone Management Act of 1972 (16 U.S.C. 1454(b)(1));

(g) *Affected State* means, with respect to any program, plan, lease sale, or other activity, proposed, conducted, or approved pursuant to the provisions of the act, any State—

(1) The laws of which are declared, pursuant to section 4(a)(2) of the Act, to be the law of the United States for the portion of the Outer Continental Shelf on which such activity is, or is proposed to be conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or structure referred to in section 4(a)(1) of the Act;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted from the Outer Continental Shelf and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the Outer Continental Shelf; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents, to the marine or coastal environment in the event of any oilspill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities;

(h) *Marine environment* means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, conditions, and quality of the marine ecosystem, including

the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the Outer Continental Shelf;

(i) *Coastal environment* means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, conditions, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone;

(j) *Human environment* means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities occurring on the Outer Continental Shelf;

(k) *Mineral* means oil, gas, and sulphur; it includes sand and gravel and salt used to facilitate the development and production of oil, gas, or sulphur.

(l) *Authorized officer* means any person authorized by law or by delegation of authority to or within MMS to perform the duties described in this part.

[44 FR 38276, June 29, 1979. Redesignated and amended at 47 FR 47006, 47007, Oct. 22, 1982; 54 FR 2049, Jan. 18, 1989]

§ 256.7 Cross references.

(a) For Minerals Management Service regulations governing exploration, development and production on leases, see 30 CFR parts 250 and 270.

(b) For MMS regulations governing the appeal of an order or decision issued under the regulations in this part, see 30 CFR part 290.

(c) For multiple use conflicts, see the Environmental Protection Agency listing of ocean dumping sites—40 CFR part 228.

(d) For related National Oceanic and Atmospheric Administration programs see:

(1) Marine sanctuary regulations, 15 CFR part 922;

(2) Fishermen's Contingency Fund, 50 CFR part 296;

(3) Coastal Energy Impact Program, 15 CFR part 931;

(e) For Coast Guard regulations on the oil spill liability of vessels and operators, see 33 CFR parts 132, 135, and 136.

(f) For Coast Guard regulations on port access routes, see 33 CFR part 164.

(g) For compliance with the National Environmental Policy Act, see 40 CFR parts 1500 through 1508.

(h) For Department of Transportation regulations on offshore pipeline facilities, see 49 CFR part 195.

(i) For Department of Defense regulations on military activities on offshore areas, see 32 CFR part 252.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982, and amended at 54 FR 50617, Dec. 8, 1989; 55 FR 32908, Aug. 13, 1990; 62 FR 27955, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27955, May 22, 1997, § 256.7 was amended by redesignating paragraphs (b) through (h) as (c) through (i) and adding a new paragraph (b), effective Aug. 20, 1997.

§ 256.8 Leasing maps and diagrams

(a) Any area of the OCS which has been appropriately platted as provided in paragraph (b) of this section, is subject to lease for any mineral not included in a subsisting lease issued under the act or meeting the requirements of subsection (a) of section 6 of the Act. Before any lease is offered or issued an area may be (1) withdrawn from disposition pursuant to section 12(a) of the Act, or (2) designated as an area or part of an area restricted from operation under section 12(d) of the Act.

(b) The MMS shall prepare leasing maps and official protraction diagrams of areas of the OCS. The areas included in each mineral lease shall be in accordance with the appropriate leasing map or official protraction diagram.

§ 256.10 Information to States.

(a) The information covered in this section is prepared by or directly obtained by the Director. Such information is typically not considered to be proprietary or privileged, with the primary exception of specific indications of interest in an area by industry received in response to a Call for Information issued by the Secretary. This information and all other proprietary and privileged information obtained by or under the control of the Minerals Management Service may be released

only in accordance with the regulations in 30 CFR parts 250, 251, and 252.

(b) The Director shall prepare an index to OCS information (see 30 CFR 252.5). The index shall list all relevant actual or proposed programs, plans, reports, environmental impact statements, nominations information, environmental study reports, lease sale information and any similar type of relevant information including, modifications, comments and revisions, prepared by or directly obtained by the Director under the act. The index shall be sent on a regular basis to affected States and, upon request, it shall be sent to any affected local government. The public shall be informed of the availability of the index.

(c) Upon request, the Director shall transmit to affected States, local governments or the public, a copy of any information listed in the index which is subject to the control of the MMS in accordance with the requirements and subject to the limitations of the Freedom of Information Act (5 U.S.C. 552) and regulations implementing said Act, and the regulations contained in 43 CFR part 2, except as provided in paragraph (d) of this section.

(d) Upon request, the Director shall provide relative indications of interest in areas as well as any comments filed in response to a Call for Information for a proposed sale. However, no information transmitted shall identify any particular area with the name of any particular party so as not to compromise the competitive position of any participants in the process of indicating interest.

[44 FR 38276, June 29, 1979, as amended at 47 FR 25970, June 16, 1982. Redesignated and amended at 47 FR 47006, 47007, Oct. 22, 1982]

§ 256.11 Helium.

(a) Each lease issued or continued under these regulations shall be subject to a reservation by the United States, under section 12(f) of the Act, of the ownership of and the right to extract helium from all gas produced from the leased area.

(b) In case the United States elects to take the helium, the lessee shall deliver all gas containing helium, or the portion of gas desired, to the United States at any point on the leased area or at an onshore processing facility. Delivery shall be made in the manner required by the United States to such plants or reduction works as the United States may provide.

(c) The extraction of helium shall not cause a reduction in the value of the lessee's gas or any other loss for which he is not reasonably compensated, except for the value of the helium extracted. The United States shall determine the amount of reasonable compensation. The United States shall have the right to erect, maintain and operate on the leased area any and all reduction works and other equipment necessary for the extraction of helium. The extraction of helium shall not cause substantial delays in the delivery of natural gas produced to the purchaser of that gas.

§ 256.12 Supplemental sales.

(a) The Secretary may conduct a supplemental sale in accordance with the provisions of this section.

(b) Supplemental sales shall be governed by the regulations in this part, except § 256.22.

(c) Supplemental sales shall be limited to blocks falling into one or more of the following categories:

(1) Blocks for which bids were rejected during the calendar year preceding the year of the supplemental sale in which they are reoffered or blocks for which bids were rejected in the same calendar year as the supplemental sale in which they are reoffered, except that for the initial supplemental sale only blocks for which bids were rejected after October 1, 1987, may be reoffered. If, after the initial supplemental sale, a supplemental sale is not held annually for any reason, the relevant period for determining blocks eligible for a subsequent supplemental sale may be extended to include rejected bid blocks which were eligible for the supplemental sale not held.

(2) Blocks for which the high bid was forfeited during the calendar year preceding the year of the supplemental sale in which they are reoffered or blocks for which high bids were forfeited in the same calendar year as the supplemental sale in which they are reoffered, except that for the initial supplemental sale only blocks for which

high bids were forfeited after October 1, 1987, may be reoffered. If, after the initial supplemental sale, a supplemental sale is not held annually for any reason, the relevant period for determining blocks eligible for a subsequent sale may be extended to include forfeited bid blocks which were eligible for the supplemental sale not held.

(3) Development blocks. Development blocks (including blocks susceptible to drainage) are blocks which are located on the same general geologic structure as an existing lease having a well with indicated hydrocarbons; the reservoir may or may not be interpreted to extend on to the block.

(d) Supplemental sales shall not include blocks in the Central or Western Gulf of Mexico Planning Areas.

(e) The Director may disclose the classification of blocks in supplemental sales as development blocks.

[53 FR 29886, Aug. 9, 1988]

Subpart B—Oil and Gas Leasing Program

§ 256.14 Definitions.

As used in this subpart, the term—*Affected State* and *affected States* means Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Louisiana, Texas, California, Oregon, Washington, and Alaska.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.16 Receipt and consideration of nominations; public notice and participation.

(a) During preparation of a proposed 5-year leasing program, the Secretary shall invite and consider suggestions and relevant information for such program from Governors of affected States, local government, industry, other Federal agencies, including the Attorney General in consultation with the Federal Trade Commission, and all interested parties, including the general public. This request for information shall be issued as a notice in the FEDERAL REGISTER. Local governments wishing to respond to such request shall first submit their responses to the Governor of the State in which the local government is located.

(b) The Secretary shall send letters to the Governors of the affected States requesting them to identify specific laws, goals, and policies which they believe should be considered by the Secretary in connection with the leasing program. The Secretary shall also request from the Secretary of Energy information on regional and national energy markets, on OCS production goals and on transportation networks.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.17 Review by State and local governments and other persons.

(a)(1) The Secretary shall prepare a proposed leasing program. At least 60 days prior to publication of the proposed program in the FEDERAL REGISTER, a copy of the draft of the proposed program shall be forwarded to the Governor of each affected State for comment. The Governor may solicit comments from local governments in his or her State which the Governor determines will be affected by the proposed program.

(2) The Secretary shall reply in writing to any comment on the draft of the proposed program from the Governor of an affected State which is received at least 15 days prior to the submission of the proposed program to the Congress and publication in the FEDERAL REGISTER. All such correspondence between the Secretary and Governor of such State shall accompany the proposed program when it is submitted to the Congress.

(b) The proposed leasing program shall be submitted to the Governors of the affected States for review and comment at the time it is submitted to the Congress and the Attorney General and published in the FEDERAL REGISTER. The Governor of an affected State shall, upon request from any local government affected by the program, submit a copy of the proposed program to such local government. Comments and recommendations on any aspect of the proposed program may be submitted by

a State or local government or other persons to the Secretary within 90 days after the date of its publication in the FEDERAL REGISTER. Comments and recommendations from local governments shall be submitted first to the Governor of the State in which the local government is located.

(c) At least 60 days prior to approving the final leasing program and any later significant revision, the Secretary shall submit it to the President and the Congress, together with any comments. The Secretary shall indicate in such submission why any specific recommendation of the Attorney General or of a State or local government was not accepted.

[44 FR 38276, June 29, 1979, as amended at 47 FR 25970, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.19 Periodic consultation with interested parties.

The Secretary shall provide for periodic consultation with State and local governments, existing and potential oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in any activity in or on the OCS, including those involved in fish and shellfish recovery, and recreational activities. This consultation shall take place primarily through appropriate public notice as described in §§256.16 and 256.17 and through the OCS Advisory Board and its committees, on a regional and national basis. Meetings of the OCS Advisory Board shall be held on specific issues as required by the Board's charter.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.20 Consideration of coastal zone management program.

In the development of the leasing program, consideration shall be given to the coastal zone management program being developed or administered by an affected coastal State under section 305 or 306 of the Coastal Zone Management Act of 1972 as amended, (16 U.S.C. 1454, 1455). Information concerning the relationship between a State's coastal zone management program and OCS oil and gas activity shall be requested from the Governors of the affected coastal States and from the Secretary of Commerce prior to the development of the proposed leasing program at the time information is requested under § 256.16 of this part.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

Subpart C—Reports From Federal Agencies

§ 256.22 General.

For oil and gas lease sales shown in an approved leasing schedule and as the need arises for other mineral leasing, the Director shall prepare a report describing the general geology and potential mineral resources of the area under consideration. The Director may request other interested Federal Agencies to prepare reports describing, to the extent known, any other valuable resources contained within the general area and the potential effect of mineral operations upon the resources or upon the total environment or other uses of the area.

[51 FR 6107, Feb. 20, 1986]

Subpart D—Call for Information and Nominations

§ 256.23 Information on areas.

(a) The Director may receive and consider indications of interest in areas for mineral leasing.

(b) In accordance with an approved program and schedule for the leasing of OCS lands which may contain oil and gas, the Director shall issue Calls for Information and Nominations on areas for leasing of such minerals in specified areas. The Call for Information and Nominations shall be published in the FEDERAL REGISTER and may be published in other publications as desirable. Information on areas shall be addressed to the appropriate regional Minerals Manager of the Minerals Management Service with a copy to any other office which may be specified in the Call. The Director shall also request comments on areas which should receive special concern and analysis. For an oil and gas lease sale Call Area, the Director may request comments

concerning geological conditions, including bottom hazards; archaeological sites on the seabed or nearshore; multiple uses of the proposed leasing area, including navigation, recreation, and fisheries; and other socioeconomic, biological, and environmental information.

[47 FR 25970, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982 and amended at 51 FR 21345, June 12, 1986; 59 FR 53094, Oct. 21, 1994]

§ 256.25 Areas near coastal States.

(a) At the time information is solicited for leasing of areas within 3 geographical miles seaward of the seaward boundary of any coastal State, the Secretary shall provide the Governor of that State information required under section 8(g)(1) of the Act. The Director shall furnish information identifying the areas for leasing as well as all relevant available environmental data for such areas (See 30 CFR 251.14).

(b) After receipt of information on areas within the area described in paragraph (a) of this section, the Secretary shall inform the Governor of those areas that are to be given further consideration for leasing. The Secretary shall enter into consultation with the Governor to determine whether the area may contain oil or gas pools or fields underlying both the OCS and lands subject to the jurisdiction of the State.

(c) After selection for leasing of those tracts which may have oil or gas pools or fields underlying both the OCS and lands under State jurisdiction, the Secretary shall offer the Governor an opportunity to enter into an agreement for the equitable disposition of revenues from such tracts under section 8(g)(2) of the Act.

(d) If no agreement can be reached within 90 days of the Secretary's offer, the tracts may be leased and all revenues deposited in a separate Treasury account pending equitable disposition of the revenues under sections 8(g) (3) and (4) of the Act.

[44 FR 38276, June 29, 1979, as amended at 47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982]

Subpart E—Area Identification and Tract Size

§ 256.26 General.

(a) The Director, in consultation with appropriate Federal Agencies, shall recommend to the Secretary areas identified for environmental analysis and consideration for leasing. The Director, on his/her own motion, may include in the recommendation areas in which interest has not been indicated in response to a call. In making a recommendation, the Director shall consider all available environmental information, multiple-use conflicts, resource potential, industry interest and other relevant information. Comments received from States and local governments and interested parties in response to calls for information and nominations shall be considered in making recommendations. For supplemental sales provided for by § 256.12 of this part, the Director's recommendation shall be replaced by a statement describing the results of the Director's consideration of the factors specified above in this section.

(b) The Director shall evaluate fully the potential effect of leasing on the human, marine and coastal environments, and develop measures to mitigate adverse impacts, including lease stipulations. The views and recommendations of Federal agencies, State agencies, local governments, organizations, industries and the general public shall be used as appropriate. The Director may hold public hearings on the environmental analysis after appropriate notice.

(c) In general, the Director shall seek to inform the public as soon as possible of additions or deletions that occur after the identification of areas.

[47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982 and amended at 51 FR 21345, June 12, 1986; 53 FR 29886, Aug. 9, 1988]

§ 256.28 Tract size.

(a) A tract selected for oil and gas leasing shall consist of a compact area not exceeding 5,760 acres, unless the authorized officer finds that a larger area is necessary to comprise a reasonable economic production unit.

(b) The tract size for the leasing of other minerals shall be specified in the notice of sale.

[47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982]

Subpart F—Lease Sales

§ 256.29 Proposed notice of sale.

(a) The Director shall in consultation with appropriate Federal agencies develop measures, including lease stipulations and conditions, to mitigate adverse impacts on the environments. For oil and gas lease sales, appropriate proposed stipulations and conditions shall be contained or referenced in the proposed notice of lease sale.

(b) A proposed notice of lease sale shall be submitted to the Secretary for approval. All comments and recommendations received and the Director's findings or actions thereon, shall also be forwarded to the Secretary.

(c) Upon approval by the Secretary, the proposed Notice of Sale shall be sent to the Governor of any affected State and a notice of its availability shall be published in the FEDERAL REGISTER.

[44 FR 38276, June 29, 1979, as amended at 47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982, and amended at 51 FR 37178, Oct. 20, 1986]

§ 256.31 State comments.

(a) Within 60 days after notice of a proposed lease sale, a Governor of any affected State or any affected local government in such State may submit recommendations to the Secretary regarding the size, timing or location of the proposed lease sale. Prior to submitting recommendations to the Secretary, any affected local government shall forward such recommendation to the Governor.

(b) The Secretary shall accept such recommendations of the Governor and may accept recommendations of any affected local government if he determines, after having provided the opportunity for consultation, that they provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State. A determination of the national interest shall be based on the findings, purposes and policies of the Act.

(c) The Secretary shall communicate to the Governor, in writing, the reasons for his determination to accept or reject such Governor's recommendations, or to implement any alternative means identified in consultation with the Governor to provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State.

§ 256.32 Notice of sale.

(a) Upon approval of the Secretary, the Director shall publish the notice of lease sale in the FEDERAL REGISTER as the official publication, and may publish the notice in other publications. The publication in the FEDERAL REGISTER shall be at least 30 days prior to the date of the sale. The notice shall state the place and time at which bids shall be filed, and the place, date and hour at which bids shall be opened. The notice shall contain or reference a description of the areas to be offered for lease and any stipulations, terms and conditions of the sale.

(b) Tracts shall be offered for lease by competitive sealed bidding under conditions specified in the notice of lease sale and in accordance with all applicable laws and regulations. A suggested format for bidder submissions appears in appendix A of this part.

(c) The notice of lease sale shall contain a reference to the OCS lease form which shall be issued to successful bidders.

(d) With the approval of the Secretary, the Director may defer any part of the payment of the cash bonus according to a schedule announced at the time of the notice of lease sale. Payment shall be made no later than 5 years after the date of the lease sale. The schedule shall contain provisions for guaranteed payment of a deferred bonus.

(e) In order to obtain statistical information to determine which bidding alternatives best accomplish the purposes and policies of the Act, the Director may, until September 18, 1983, require each bidder to submit bids for any OCS area in accordance with more than one of the bidding systems described in section 8(a)(1) of the Act. No

more than 10 percent of the tracts offered each year shall contain such a requirement. Leases may be awarded using a bidding alternative selected at random for statistical purposes, if it is otherwise consistent with the purposes and policies of the Act.

[44 FR 38276, June 29, 1979. Redesignated and amended at 47 FR 25971, June 16, 1982. Further redesignated at 47 FR 47006, Oct. 22, 1982]

Subpart G—Issuance of Leases

§256.35 Qualifications of lessees.

(a) In accordance with section 8 of the Act, leases shall be awarded only to the highest responsible qualified bidder.

(b) Mineral leases issued pursuant to section 8 of the Act may be held only by: (1) Citizens and nationals of the United States, (2) aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20); (3) private, public or municipal corporations organized under the laws of the United States or of any State or of the District of Columbia or territory thereof, or (4) associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

§256.37 Lease term.

(a)(1) All oil and gas leases shall be issued for an initial period of 5 years, or not to exceed 10 years where the authorized officer finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions.

(2) If your oil and gas lease is in water depths between 400 and 800 meters, it will have an initial lease term of 8 years unless MMS establishes a different lease term under paragraph (a)(1) of this section.

(3) For leases issued with an initial term of 8 years, you must begin an exploratory well within the first 5 years of the term to avoid lease cancellation.

(b) An oil and gas lease shall continue after such initial period for as long as oil or gas is produced from the lease in paying quantities, or drilling or well reworking operations as approved by the Secretary are conducted. The term of an oil and gas lease is subject to further extension as provided in §256.73 of this part.

(c) Sulphur leases shall be issued for a term not to exceed 10 years and so long thereafter as sulphur is produced from the leasehold in paying quantities, or drilling, well reworking, plant construction, or other operations for the production of sulphur, as approved by the Secretary, are conducted thereon.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982 and amended at 50 FR 49043, Nov. 29, 1985; 54 FR 2049, Jan. 18, 1989; 61 FR 55889, Oct. 30, 1996]

§256.38 Joint bidding provisions.

§256.40 Definitions.

The following definitions shall be applicable to §256.38 of this part:

(a) *Single bid* means a bid submitted by one person for an oil and gas lease under section 8(a) of the Act.

(b) *Joint bid* means a bid submitted by two or more persons for an oil and gas lease under section 8(a) of the Act.

(c) *Average daily production* is the total of all production in an applicable production period which is chargeable under §256.43 of this title divided by the exact number of calendar days in the applicable production period.

(d) *Barrel* means 42 U.S. gallons.

(e) *Crude oil* means a mixture of liquid hydrocarbons including condensate that exists in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities, but does not include liquid hydrocarbons produced from tar sand, gilsonite, oil shale, or coal.

(f) *An economic interest* means any right to, or any right dependent upon, production of crude oil, natural gas, or liquefied petroleum products and shall include, but not be limited to, a royalty interest, or overriding royalty interest, whether payable in cash or in kind, a working interest, a net profits interest, a production payment, or a carried interest.

(g) *Liquefied petroleum products* means natural gas liquid products including the following: ethane, propane, butane, pentane, natural gasoline, and other

natural gas products recovered by a process of absorption, adsorption, compression, or refrigeration cycling, or a combination of such processes.

(h) *Natural gas* means a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist in the gaseous phase.

(i) *Oil and gas lease* means an oil and gas lease either offered or issued pursuant to the provisions of the Act.

(j) *Owned* means:

(1) *With respect to crude oil*—having either an economic interest in or a power of disposition over the production of crude oil;

(2) *With respect to natural gas*—having either an economic interest in or a power of disposition over the production of natural gas; and

(3) *With respect to liquefied petroleum products*—having either an economic interest in or a power of disposition over any liquefied petroleum product at the time of completion of the liquefaction process.

(k) *Prior production period* means the continuous six month period of January 1 through June 30 preceding November 1 through April 30 for joint bids submitted during the six month bidding period from November 1 through April 30, and means the continuous six month period of July 1 through December 31 preceding May 1 through October 31 for joint bids submitted during the six month bidding period from May 1 through October 31.

(l) *Production*—(1) *Of crude oil* means the volume of crude oil produced worldwide from reservoirs during the prior production period. The amount of such crude oil production shall be established by measurement of volumes delivered at the point of custody transfer (e.g., from storage tanks to pipelines, trucks, tankers, or other media for transport to refineries or terminals) with adjustments for:

(i) Net differences between opening and closing inventories, and

(ii) Basic sediment and water;

(2) *Of natural gas* means the volume of natural gas produced worldwide from natural oil and gas reservoirs during the prior production period, with adjustments, where applicable, to reflect

(i) The volume of gas returned to natural reservoirs; and

(ii) The reduction of volume resulting from the removal of natural gas liquids and nonhydrocarbon gases.

(3) *Of liquefied petroleum products* means the volume of natural gas liquids produced from reservoir gas and liquefied at surface separators, field facilities, or gas processing plants worldwide during the prior production period; these liquefied petroleum products include the following:

(i) *Condensate*—natural gas liquids recovered from gas well gas (associated and non-associated) in separators or field facilities;

(ii) *Gas plant products*—natural gas liquids recovered from natural gas in gas processing plants and from field facilities. Gas plant products shall include the following as classified according to the standards of the Natural Gas Processors Association (NGPA) or the American Society for Testing and Materials (ASTM):

(A) Ethane—C_2H_6

(B) Propane—C_3H_8

(C) Butane—C_4H_{10} including all products covered by NGPA specifications for commercial butane.

(*1*) Isobutane,

(*2*) Normal butane,

(*3*) Other butanes—all butanes not included as isobutane or normal butane;

(D) Butane-Propane Mixtures—All products covered by NGPA specifications for butane-propane mixtures;

(E) Natural Gasoline—A mixture of hydrocarbons extracted from natural gas, which meet vapor pressure, end point, and other specifications for natural gasoline set by NGPA;

(F) Plant Condensate—A natural gas plant product recovered and separated as a liquid at gas inlet separators or scrubbers in processing plants or field facilities; and

(G) Other Natural Gas Plant Products meeting refined product standards (i.e., gasoline, kerosene, distillate, etc.).

(m) *Six month bidding period* means the six month period of time

(1) From May 1 through October 31; or

(2) From November 1 through April 30, respectively.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982]

§256.41 Joint bidding requirements.

(a) Any person who submits a joint bid for any oil and gas lease during a 6-month bidding period, and who was chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products, shall have filed under oath with the Director, a Statement of Production of crude oil, natural gas and liquified petroleum products, hereinafter referred to as a Statement of Production, no later than 45 days prior to the commencement of the applicable 6-month bidding period of May 1 through October 31, and November 1 through April 30. Statements of Production shall be submitted to the Director, MMS (Attention: Offshore Leasing Management Division), Washington, DC 20240. The Statement of Production shall indicate that the person was chargeable, in accordance with §256.43 of this part, with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products for the prior production period. The Director shall publish semi-annually in the FEDERAL REGISTER a ''List of Restricted Joint Bidders'' to be effective immediately upon publication and to continue in force and effect until a subsequent list is published. The ''List of Restricted Joint Bidders'' shall consist of those persons, who in the judgment of the Director, based on information available to him, including, but not limited to, sworn Statements of Production, are chargeable under §256.43 of this part with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products for the prior production period.

(b) When a person is placed on the List of Restricted Joint Bidders the Director shall serve that person either personally or by certified mail, return receipt requested, with a copy of the Director's Order placing that person on the List of Restricted Joint Bidders. Any appeal from that Order or from an adverse effect of that Order shall be made in accordance with the provisions of 43 CFR part 4.

(c) The submission of a Statement of Production or of a detailed Report of Production under §256.46(g) of this part which misrepresents the chargeable production of the reporting person shall constitute failure to comply with these regulations and any lease awarded in reliance on that Statement or Report of Production may be canceled, pursuant to section 8(o) of the Act and regulations issued thereunder as having been obtained by fraud or misrepresention.

(d) The Secretary may exempt a person from the provisions of §§256.41(a), 256.44, 256.46(g) and 256.62(b) of this part if it is found, on the record, after an opportunity for an agency hearing, that lands being offered have extremely high cost exploration and development problems and that exploration and development will not occur on such lands unless the exemption is granted.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979, as amended at 45 FR 69174, Oct. 17, 1980; 47 FR 25971, June 16, 1982. Redesignated and amended at 47 FR 47006, 47007, Oct. 22, 1982]

§256.43 Chargeability for production.

(a) As used in this section the following definitions shall control:

(1) *Person* means a natural person or company.

(2) *Company* means a corporation, a partnership, an association, a joint-stock company, a trust, a fund, or any group of persons whether incorporated or not; it also means any receiver, trustee in bankruptcy, or similar official acting for such a company.

(3) *Subsidiary* means a company 50 percent or more of whose stock or other interest having power to vote for the election of directors, trustees, or other similar controlling body of the company is directly or indirectly owned, controlled, or held with the power to vote by another company; a subsidiary shall be deemed a subsidiary of the other company owning, controlling, or holding 50 percent or more of the stock or other voting interest.

(4) *Security or securities* means any note, stock, treasury stock, bond, debenture, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement, collateral-trust certificate, pre-organization certificate or subscription, transferable

share, investment contract, voting-trust certificate, certificate of deposit for a security, fractional undivided interest in oil, gas, or other mineral rights, or, in general, any interest or instrument commonly known as a ''security'' or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guarantee of, or warrant or right to subscribe to or purchase any of the foregoing.

(b) A person filing a Statement of Production under § 256.41 of this part shall be charged with the following production during the applicable prior production period:

(1) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products which it owned worldwide;

(2) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every subsidiary of the reporting person;

(3) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any person or persons of which the reporting person is a subsidiary; and

(4) The average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by any subsidiary, other than the reporting person, of any person or persons of which the reporting person is a subsidiary.

(c) A person filing a Statement of Production shall be charged with, in addition to the production chargeable under paragraph (b) of this section, but not in duplication thereof, its proportionate share of the average daily production in barrels of crude oil, natural gas, and liquefied petroleum products owned worldwide by every person:

(1) Which has an interest in the reporting person, and

(2) In which the reporting person has an interest, whether the interest referred to in paragraphs (c) (1) and (2) of this section is by virtue of ownership of securities or other evidence of ownership, or by participation in any contract, agreement, or understanding respecting the control of any person or of any person's production of crude oil, natural gas, or liquefied petroleum products, equal to said interest. As used in paragraph (c) of this section ''interest'' means an interest of at least 5 percent of the ownership or control of a person.

(d) All measurements of crude oil and liquefied petroleum products under this section shall be at 60° F.

(e)(1) For purposes of computing production of natural gas under § 256.41 of this part, chargeability under this section, and reporting under § 256.46(g) of this part, 5,626 cubic feet of natural gas at 14.73 pounds per square inch (msl) shall equal one barrel.

(2) For purposes of computing production of liquefied petroleum products under § 256.41 of this part, chargeability under § 256.46(g) of this part, 1.454 barrels of natural gas liquids at 60° F shall equal one barrel of crude oil.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979, as amended at 47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, 47007, Oct. 22, 1982]

§ 256.44 Bids disqualified.

The following bids for any oil and gas lease shall be disqualified and rejected in their entirety:

(a) A joint bid submitted by 2 or more persons who are on the effective List of Restricted Joint Bidders; or

(b)(1) A joint bid submitted by two or more persons when 1 or more of those persons is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products and has not filed a Statement of Production as required by § 256.41 of this part for the applicable 6-month bidding period, or

(2) Any of those persons have failed or refused to file a detailed report of production when required to do so under § 256.46(g) of this part, or

(c) A single or joint bid submitted pursuant to an agreement (whether written or oral, formal or informal, entered into or arranged prior to or simultaneously with the submission of such single or joint bid, or prior to or simultaneously with the award of the bid upon the tract) which provides:

(1) For the assignment, transfer, sale, or other conveyance of less than a 100 percent interest in the entire tract on which the bid is submitted, by a person

or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or

(2) For the assignment, sale, transfer or other conveyance of less than a 100 percent interest in any fractional interest in the entire tract (which fractional interest was originally acquired by the person making the assignment, sale, transfer or other conveyance, under the provisions of the act) by a person or persons on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to another person or persons on the same List of Restricted Joint Bidders; or

(3) For the assignment, sale, transfer, or other conveyance of any interest in a tract by a person or persons not on the List of Restricted Joint Bidders, effective on the date of submission of the bid, to 2 or more persons on the same List of Restricted Joint Bidders; or

(4) For any of the types of conveyances described in paragraphs (c) (1), (2) or (3) of this section where any party to the conveyance is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas and liquified petroleum products and has not filed a Statement of Production pursuant to §256.41 of this part for the applicable 6-month bidding period. Assignments expressly required by law, regulation, lease or stipulation to lease shall not disqualify an otherwise qualified bid; or

(d) A bid submitted by or in conjunction with a person who has filed a false, fraudulent or otherwise intentionally false or misleading detailed Report of Production.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979, as amended at 45 FR 69175, Oct. 17, 1980; 47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982]

§256.46 Submission of bids.

(a) A separate sealed bid shall be submitted for each tract unit bid upon as described in the notice of lease sale. A bid may not be submitted for less than an entire tract.

(b) Each bidder shall submit with the bid, a certified or cashier's check or bank draft on a solvent bank, or cash, or any other form of payment approved by the Secretary for one-fifth of the amount of the cash bonus, unless otherwise stated in the Notice of Sale.

(c) If the bidder is an individual a statement of citizenship shall accompany the bid.

(d) If the bidder is an association (including a partnership), the bid shall be accompanied by a certified statement indicating the State in which it is registered and that it is authorized to hold mineral leases on the OCS, or appropriate reference to statements or records previously submitted to an MMS OCS office (including material submitted in compliance with prior regulations).

(e) If the bidder is a corporation, the following information shall be submitted with the bid:

(1) A statement certified by the corporate Secretary or Assistant Secretary over the corporate seal showing the State in which it was incorporated and that it is authorized to hold mineral leases on the OCS, or appropriate reference to statements or records previously submitted to an MMS OCS office (including material submitted in compliance with prior regulations).

(2) Evidence of authority of persons signing to bind the corporation. Such evidence may be in the form of either a certified copy of the minutes of the board of directors or of the bylaws indicating that the person signing has authority to do so; or a certificate to that effect signed by the Secretary or Assistant Secretary of the corporation over the corporate seal, or appropriate reference to statements or records previously submitted to an MMS OCS office (including material submitted in compliance with prior regulations). Bidders are advised to keep their filings current.

(3) The bid shall be executed in conformance with corporate requirements.

(f) Bidders should be aware of the provisions of 18 U.S.C. 1860, prohibiting unlawful combination or intimidation of bidders.

(g) To verify the accuracy of any statement submitted pursuant to §256.41 of this part, the Director may require the person submitting such information to:

(1) Submit no later than 30 days after receipt of the request by the Director, a detailed Report of Production which shall list, in barrels, the average daily production of crude oil, natural gas and liquefied petroleum products chargeable to the reporting person in accordance with § 256.43 of this part for the prior production period, and

(2) Permit the inspection and copying by an official of the Department of the Interior of such documents, records of production of crude oil, natural gas and liquified petroleum products, analyses and other material as are necessary to demonstrate the accuracy of any statement or information contained in any Report of Production.

(h) No bid for a lease may be submitted if the Secretary finds, after notice and hearing, that the bidder is not meeting due diligence requirements on other OCS leases.

[44 FR 38276, June 29, 1979, as amended at 45 FR 69175, Oct. 17, 1980; 47 FR 25971, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982]

§ 256.47 Award of leases.

(a) Sealed bids received in response to the notice of lease sale shall be opened at the place, date and hour specified in the notice. The opening of bids is for the sole purpose of publicly announcing and recording the bids received and no bids shall be accepted or rejected at that time.

(b) The United States reserves the right to reject any and all bids received for any tract, regardless of the amount offered.

(c) In the event the highest bids are tie bids, the tie bidders (unless they would be disqualified under § 256.35(b) of this part, or disqualified under § 256.44 of this part if their bids had been joint bids) may file with the Director, within 15 days after notification, an agreement to accept the lease jointly; otherwise all bids shall be rejected.

(d) Pursuant to section 8(c) of the Act, the Attorney General may review the results of the lease sale prior to the acceptance of bids and issuance of leases.

(e)(1) The decision of the authorized officer on bids shall be the final action of the Department, subject only to reconsideration by the Secretary, pursuant to written request, of the rejection of the high bid. The delegation of review authority to the Office of Hearings and Appeals shall not be applicable to decisions on high bids for leases on the Outer Continental Shelf.

(2) The authorized officer must accept or reject the bid within 90 days. The authorized officer may extend the time period for acceptance or rejection of a bid for 15 working days or longer, if circumstances warrant. Any bid not accepted within the prescribed time period, including any extension thereof, is deemed rejected.

(3) Any high bidder whose bid is rejected by the authorized officer may, within 15 days of such rejection, file with the Secretary, with a copy to the authorized officer, a written request for reconsideration accompanied by a statement of reasons. The Secretary shall respond in writing either affirming or reversing the decision of the authorized officer.

(f) Written notice of the authorized officer's action shall be transmitted promptly to those bidders whose deposits have been held. If a bid is accepted, such notice shall transmit three copies of the lease to the successful bidder. As provided in § 218.155, the bidder shall, not later than the 11th business day after receipt of the lease, execute the lease, pay the first-year's rental, and unless deferred, pay the balance of the bonus bid. The bidder must also file a bond as required in § 256.52 of this title. Deposits and any interest accrued shall be refunded on high bids subsequently rejected.

(g) If the successful bidder fails to execute the lease within the prescribed time or otherwise comply with the applicable regulations the deposit shall be forfeited and disposed of as other receipts under the act.

(h) If, before the lease is executed on behalf of the United States, the land which would be subject to the lease is withdrawn or restricted from leasing, all deposits and any interest due shall be refunded.

(i) If the awarded lease is executed by an agent acting on behalf of the bidder, the lease shall be accompanied by evidence that the bidder authorized the agent to execute the lease. When three

copies of the lease are executed and returned to the authorized officer, the lease shall be executed on behalf of the United States, and one fully executed copy shall be transmitted to the successful bidder.

(j) No lease or permit shall be issued for any area within 15 statute miles of the boundaries of the Point Reyes Wilderness in California unless the State of California allows exploration, development or production activities in the adjacent navigable waters of the State under section 11(h) of the Act.

[44 FR 38276, June 29, 1979, as amended at 47 FR 25972, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982, and amended at 49 FR 8606, Mar. 8, 1984; 49 FR 10056, Mar. 16, 1984; 50 FR 47378, Nov. 18, 1985; 61 FR 34732, July 3, 1996; 62 FR 27955, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27955, May 22, 1997, §256.47 was amended by revising the fourth sentence in paragraph (f), effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§256.47 Award of leases.

* * * * *

(f)* * *The bidder shall also file a bond as required in §256.58 of this title.* * *

* * * * *

§256.49 Lease form.

Oil and gas leases and leases for sulphur shall be issued on forms approved by the Director. Other mineral leases shall be issued on such forms as may be prescribed by the Secretary.

[47 FR 25972, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982]

§256.50 Dating of leases.

All leases issued under the regulations in this part shall be dated and become effective as of the first day of the month following the date leases are signed on behalf of the lessor. When prior written request is made, a lease may be dated and become effective as of the first day of the month within which it is so signed.

Subpart H—Rentals and Royalties [Reserved]

Subpart I—Bonding

§256.52 Bond requirements for an oil and gas or sulphur lease.

This section establishes bond requirements for the lessee of an OCS oil and gas or sulphur lease.

(a) Before MMS will issue a new lease or approve the assignment of an existing lease to you as lessee, you or another record title owner for the lease must:

(1) Maintain with the Regional Director a $50,000 lease bond that guarantees compliance with all the terms and conditions of the lease; or

(2) Maintain a $300,000 areawide bond that guarantees compliance with all the terms and conditions of all your oil and gas and sulphur leases in the area where the lease is located; or

(3) Maintain a lease or areawide bond in the amount required in §256.53(a) or (b) of this part.

(b) For the purpose of this section, there are four areas:

(1) The Gulf of Mexico;

(2) The area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii;

(3) The area offshore the Coast of Alaska; and

(4) The area offshore the Atlantic Coast.

(c) The requirement to maintain a lease bond (or substitute security instruments) under paragraph (a)(1) of this section and §256.53 (a) and (b) is satisfied if your operator provides a lease bond in the required amount that guarantees compliance with all the terms and conditions of the lease. Your operator may not use an areawide bond under this paragraph to satisfy your bond obligation.

(d) If a surety makes payment to the United States under a bond or alternate form of security maintained under this section, the surety's remaining liability under the bond or alternate form of security is reduced by the

amount of that payment. See paragraph (e) of this section for the requirement to replace the reduced bond coverage.

(e) If the value of your surety bond or alternate security is reduced because of a default, or for any other reason, you must provide additional bond coverage sufficient to meet the security required under this subpart within 6 months, or such shorter period of time as the Regional Director may direct.

(f) You may pledge U.S. Department of the Treasury (Treasury) securities instead of a bond. The Treasury securities you pledge must be negotiable for an amount of cash equal to the value of the bond they replace.

(1) If you pledge Treasury securities under this paragraph (f), you must monitor their value. If their market value falls below the level of bond coverage required under this subpart, you must pledge additional Treasury securities to raise the value of the securities pledged to the required amount.

(2) If you pledge Treasury securities, you must include authority for the Regional Director to sell them and use the proceeds when the Regional Director determines that you fail to satisfy any lease obligation.

(g) You may pledge alternate types of security instruments instead of providing a bond if the Regional Director determines that the alternate security protects the interests of the United States to the same extent as the required bond.

(1) If you pledge an alternate type of security under this paragraph, you must monitor the security's value. If its market value falls below the level of bond coverage required under this subpart, you must pledge additional securities to raise the value of the securities pledged to the required amount.

(2) If you pledge an alternate type of security, you must include authority for the Regional Director to sell the security and use the proceeds when the Regional Director determines that you failed to satisfy any lease obligation.

(h) If you fail to replace a deficient bond or to provide additional bond coverage upon demand, the Regional Director may:

(1) Assess penalties under part 250, subpart N of this chapter;

(2) Suspend production and other operations on your leases in accordance with § 250.10 of this chapter; and

(3) Initiate action to cancel your lease.

[62 FR 27955, May 22, 1997.]

EFFECTIVE DATE NOTE: At 62 FR 27955, May 22, 1997, § 256.58 was redesignated as § 256.52 and revised, effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 256.58 Acceptable bonds/alternate security instruments.

(a) The successful bidder, prior to the issuance of an oil and gas or sulphur lease, shall furnish the authorized officer a surety bond in the amount of $50,000 conditioned on compliance with all the terms and conditions of the lease. A $50,000 lease surety bond need not be submitted and maintained if the bidder furnishes and maintains an areawide bond in the sum of $300,000 issued by a qualified surety and conditioned on compliance with all the terms and conditions of oil and gas and sulphur leases held by the bidder on the OCS for the area in which the lease to be issued in situated, furnishes and maintains an areawide bond under § 256.61 (a)(2) or (b)(2) of this part, or submits a substitute security instrument in accordance with paragraphs (f) and (g) of this section.

(b) For the purposes of this section, there are four areas:

(1) The Gulf of Mexico;

(2) The area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii;

(3) The area offshore the Coast of Alaska; and

(4) The area offshore the Atlantic Coast.

(c)(1) A lessee shall provide a separate areawide surety bond furnished and maintained pursuant to paragraph (a) of this section, or § 256.61 of this part, or a separate areawide alternate security instrument furnished pursuant to paragraphs (f) or (g) of this section, to secure the performance of lessee's obligation to comply with all the terms and conditions of leases in each of the areas identified in paragraph (b) of this section in which leases are held.

(2) An operator's bond in the same amount as the lease bond required under paragraph (a) of this section, or § 256.61 of this part, or alternate security instruments of the same amount as provided for in paragraphs (f) and (g) of this section, may be substituted at any time for the equivalent lessee's bond. The substitution of an operator's bond or alternate security instrument for a lessee's bond shall not relieve the lessee of its obligation to comply with the terms and conditions of the lease.

(d) If, as the result of a default, the surety on a Mineral Lease Bond makes payment to the United States of any indebtedness under a lease secured by the bond, the face amount of such bond and the surety's liability shall be reduced by the amount of such payment.

(e) If any bond has been reduced by any amount as the result of payment for default, the lessee must post a new bond in at least the amount of the original face value of the reduced bond within 6 months or such shorter period of time as the authorized officer may direct after a default. If the reduced bond is an individual lease bond, the lessee or operator may replace it with an areawide bond as provided in paragraph (a) of this section or § 256.61 (a)(2) or (b)(2) of this part. Failure to post such a new bond shall, at the discretion of the authorized officer, be the basis of cancellation of the lease(s) covered by the defaulted bond.

(f) U.S. Department of the Treasury (U.S. Treasury) securities (U.S. Bonds or Notes) may be submitted in lieu of a bond, provided the U.S. Treasury instrument or legal tender submitted is negotiable at the time of submission for an amount of cash equal to the value of the required bond.

(g) The authorized officer may approve the submission of alternate types of securities or collateral in lieu of the surety bonds required by this section if:

(1) The authorized officer determines that the interests of the Government are protected to the same extent that these interests would be protected by a surety bond, and

(2) The substitute security instrument is not limited in its term and is not revocable.

(h) With the approval of the Secretary, the Director may provide at the time of the notice of lease sale that (1) the successful bidder for a lease where payment of any part of the cash bonus has been deferred pursuant to 43 U.S.C. 1337(a)(2), as implemented by 30 CFR 256.32(d), shall furnish the authorized officer a corporate surety bond in the amount of the cash bonus deferred conditioned on payment of the cash bonus deferred according to the notice of lease sale; and (2) the high bidder for a lease where the decision to accept the high bid has been deferred, pursuant to 43 U.S.C. 1337(a)(1), as implemented by 30 CFR 256.47(e)(2), shall furnish the authorized officer a corporate surety bond in the amount of the bid not already remitted, conditioned on payment of the yet to be remitted amount after the bidder has been notified that his high bid has been accepted, within the time specified in the notice of lease sale.

§ 256.53 Additional bonds.

(a) This paragraph explains what bonds the lessee must provide before lease exploration activities commence.

(1)(i) You must furnish the Regional Director a $200,000 bond that guarantees compliance with all the terms and conditions of the lease by the earliest of:

(A) The date you submit a proposed Exploration Plan (EP) for approval;

(B) The date you submit a request for approval of the assignment of a lease on which an EP has been approved; or

(C) December 8, 1997, for any lease for which an EP has been approved.

(ii) The Regional Director may authorize you to submit the $200,000 lease exploration bond after you submit an EP but before he/she approves drilling activities under the EP.

(iii) You may satisfy the bond requirement of this paragraph (a) by providing a new bond or by increasing the amount of your existing bond.

(2) A $200,000 lease exploration bond pursuant to paragraph (a)(1) of this section need not be submitted and maintained if the lessee either:

(i) Furnishes and maintains an areawide bond in the sum of $1 million issued by a qualified surety and conditioned on compliance with all the terms and conditions of oil and gas and sulphur leases held by the lease on the OCS for the area in which the lessee is situated; or

(ii) Furnishes and maintains a bond pursuant to paragraph (b)(2) of this section.

(b) This paragraph explains what bonds you (the lessee) must provide before lease development and production activities commence.

(1)(i) You must furnish the Regional Director a $500,000 bond that guarantees compliance with all the terms and conditions of the lease by the earliest of:

(A) The date you submit a proposed Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD) for approval;

(B) The date you submit a request for approval of the assignment of a lease on which a DPP or DOCD has been approved; or

(C) December 8, 1997, for any lease for which a DPP or DOCD has been approved.

(ii) The Regional Director may authorize you to submit the $500,000 lease

development bond after you submit a DPP or DOCD, but before he/she approves the installation of a platform or the commencement of drilling activities under the DPP or DOCD.

(iii) You may satisfy the bond requirement of this paragraph by providing a new bond or by increasing the amount of your existing bond.

(2) The lessee need not submit and maintain a $500,000 lease development bond pursuant to paragraph (b)(1) of this section if the lessee furnishes and maintains an areawide bond in the sum of $3 million issued by a qualified surety and conditioned on compliance with all the terms and conditions of oil and gas and sulphur leases held by the lessee on the OCS for the area in which the lease is situated.

(c) When a lessee can demonstrate to the satisfaction of the authorized officer that wells and platforms can be abandoned and removed and the drilling and platform sites cleared of obstructions for less than the amount of lease bond coverage required under paragraph (b)(1) of this section, the authorized officer may accept a lease surety bond in an amount less than the prescribed amount but not less than the amount of the cost for well abandonment, platform removal, and site clearance.

(d) The Regional Director may determine that additional security (i.e., security above the amounts prescribed in §§ 256.52(a) and 256.53 (a) and (b) of this part) is necessary to ensure compliance with the obligations under your lease and the regulations in this chapter.

(1) The Regional Director's determination will be based on his/her evaluation of your ability to carry out present and future financial obligations demonstrated by:

(i) Financial capacity substantially in excess of existing and anticipated lease and other obligations, as evidenced by audited financial statements (including auditor's certificate, balance sheet, and profit and loss sheet);

(ii) Projected financial strength significantly in excess of existing and future lease obligations based on the estimated value of your existing OCS lease production and proven reserves of future production;

(iii) Business stability based on 5 years of continuous operation and production of oil and gas or sulphur in the OCS or in the onshore oil and gas industry;

(iv) Reliability in meeting obligations based on:

(A) Credit rating(s); or

(B) Trade references, including names and addresses of other lessees, drilling contractors, and suppliers with whom you have dealt; and

(v) Record of compliance with laws, regulations, and lease terms.

(2) You may satisfy the Regional Director's demand for additional security by increasing the amount of your existing bond or by providing a supplemental bond or bonds.

(e) The Regional Director will determine the amount of supplemental bond required to guarantee compliance. The Regional Director will consider potential underpayment of royalty and cumulative obligations to abandon wells, remove platforms and facilities, and clear the seafloor of obstructions in the Regional Director's case-specific analysis.

(f) If your cumulative potential obligations and liabilities either increase or decrease, the Regional Director may adjust the amount of supplemental bond required.

(1) If the Regional Director proposes an adjustment, the Regional Director will:

(i) Notify you and the surety of any proposed adjustment to the amount of bond required; and

(ii) Give you an opportunity to submit written or oral comment on the adjustment.

(2) If you request a reduction of the amount of supplemental bond required, you must submit evidence to the Regional Director demonstrating that the projected amount of royalties due the Government and the estimated costs of lease abandonment and cleanup are less than the required bond amount. If the Regional Director finds that the evidence you submit is convincing, he/she may reduce the amount of supplemental bond required.

[58 FR 45262, Aug. 27, 1993. Redesignated and amended at 62 FR 27956, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27956, May 22, 1997, § 256.61 was redesignated as § 256.53 of

subpart I; introductory texts were added to paragraphs (a) and (b); paragraphs (a)(1), (b)(1), and (d) were revised; and paragraphs (e) and (f) were added, effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 256.61 Additional bonds.

(a)(1) A surety bond in the amount of $200,000 issued by a qualified surety, and conditioned on compliance with all the terms and conditions of the lease, shall be furnished to the authorized officer with a proposed Exploration Plan (EP) or a proposed assignment of a lease with an approved EP submitted for approval on or after November 26, 1993. Approval of the EP or assignment shall be conditioned upon receipt of a lease surety bond in the amount of $200,000, unless the authorized officer, for good cause, authorizes the submission of the $200,000 lease exploration bond after the submission of the EP but prior to approval of drilling activities under the approved EP. This bond coverage may be provided by increasing the bond coverage provided pursuant to § 256.58(a) of this part.

* * * * *

(b)(1) A surety bond in the amount of $500,000 issued by a qualified surety and conditioned on compliance with all the terms and conditions of the lease shall be furnished to the authorized officer with a proposed Development and Production Plan (DPP), Development Operations Coordination Document (DOCD), or a proposed assignment of a lease with an approved DPP or DOCD submitted for approval on or after November 26, 1993. Approval of a DPP, DOCD, or assignment of a lease with an approved DPP or DOCD shall be conditioned on receipt of a lease surety bond in the amount of $500,000, unless the authorized officer, for good cause, authorizes the submission of the $500,000 lease development bond after the submission of the DPP or DOCD but prior to the approval of platform installation or drilling activities under the approved DPP or DOCD. The lessee may provide this additional bond by submission of a new bond or by increasing the lease bond coverage of $200,000 provided under paragraph (a) of this section.

* * * * *

(d) The authorized officer may require additional security (i.e., security over and above the amounts prescribed in §§ 256.58(a) and 256.61 (a), (b), and (c) of this part) in the form of a supplemental bond or bonds or increased amount of coverage of an existing surety bond if the authorized officer deems such additional security necessary to cover royalty due the Government or costs and liabilities of the lessee for regulatory compliance, e.g., abandonment of wells, removal of platforms, and clearance of equipment and facilities from the lease once production ceases and the lease expires. The authorized officer shall base the decision on an evaluation of the ability of the lessee to carry out its present and future financial obligations, as demonstrated by factors such as:

(1) Financial capacity of the lessee substantially in excess of existing and anticipated lease and other obligations (including but not limited to well abandonment, platform removal, and royalty due to the Government) as evidenced by audited financial statements including auditor's certificate, balance sheet, and profit and loss sheet;

(2) Projected financial strength as evidenced by existing OCS production and proven reserves of future production valued significantly in excess of existing and future obligations;

(3) Business stability as evidenced by years of successful operation in the OCS or in the oil and gas industry;

(4) Reliability in meeting obligations as evidenced by credit ratings and trade references (for which purpose a lessee shall upon request furnish a list of the names and addresses of lessees, drilling contractors, and suppliers with whom it has dealt); and

(5) Record of compliance with laws, regulations, and lease terms.

§ 256.54 General requirements for bonds.

(a) Any bond or other security that you, as lessee or operator, provide under this part must:

(1) Be payable upon demand to the Regional Director;

(2) Guarantee compliance with all of your obligations under the lease and regulations in this chapter; and

(3) Guarantee compliance with the obligations of all lessees, operating rights owners and operators on the lease.

(b) All bonds and pledges you furnish under this part must be on a form or in a form approved by the Associate Director for Offshore Minerals Management. Surety bonds must be issued by a surety that the Treasury certifies as an acceptable surety on Federal bonds and that is listed in the current Treasury Circular No. 570. You may obtain a copy of the current Treasury Circular No. 570 from the Surety Bond Branch, Financial Management Service, Department of the Treasury, East-West Highway, Hyattsville, MD 20782.

(c) You and a qualified surety must execute your bond. When either party is a corporation, an authorized official for the party must sign the bond and attest to it by an imprint of the corporate seal.

(d) Bonds must be noncancellable, except as provided in § 256.58 of this part. Bonds must continue in full force and effect even though an event occurs that could diminish, terminate, or cancel a surety obligation under State surety law.

(e) Lease bonds must be:

(1) A surety bond;

(2) Treasury securities as provided in § 256.52(f);

(3) Another form of security approved by the Regional Director; or

(4) A combination of these security methods.

(f) You may submit a bond to the Regional Director executed on a form approved under paragraph (b) of this section that you have reproduced or generated by use of a computer. If you do this, and if the document omits terms or conditions contained on the form approved by the Associate Director for Offshore Minerals Management the bond you submit will be deemed to contain the omitted terms and conditions.

[62 FR 27956, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27956, May 22, 1997, § 256.59 was redesignated as § 256.54 and revised, effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 256.59 Bond form.

All bonds furnished by a bidder, lessee, or operator shall be on a form, or in a form, approved by the Director. Bonds required by this part and submitted after November 26, 1993 shall be issued by a qualified surety company certified by the U.S. Treasury as an acceptable surety on Federal bonds and listed in the current U.S. Treasury Circular No. 570 which is available from Surety Bond Branch, Financial Management Service, Department of the Treasury, 401 14th Street, SW., Washington, DC 20227.

§ 256.55 Lapse of bond.

(a) If your surety becomes bankrupt, insolvent, or has its charter or license suspended or revoked, any bond coverage from that surety terminates immediately. In that event, you must promptly provide a new bond in the amount required under §§ 256.52 and 256.53 of this part to the Regional Director and advise the Regional Director of the lapse in your previous bond.

(b) You must notify the Regional Director of any action filed alleging that you, your surety, or guarantor are insolvent or bankrupt. You must notify the Regional Director within 72 hours of learning of such an action. All bonds must require the surety to provide this information to you and directly to MMS.

[62 FR 27957, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27957, May 22, 1997, § 256.55 was added, effective Aug. 20, 1997.

§ 256.56 Lease-specific abandonment accounts.

(a) The Regional Director may authorize you to establish a lease-specific abandonment account in a federally insured institution in lieu of the bond required under § 256.53(d). The account must provide that, except as provided in paragraph (a)(3) of this section, funds may not be withdrawn without the written approval of the Regional Director.

(1) Funds in a lease-specific abandonment account must be payable upon demand to MMS and pledged to meet the lessee's obligations under § 250.110 of this chapter.

(2) You must fully fund the lease-specific abandonment account to cover all the costs of lease abandonment and site clearance as estimated by MMS within the timeframe the Regional Director prescribes.

(3) You must provide binding instructions under which the institution managing the account is to purchase Treasury securities pledged to MMS under paragraph (d) of this section.

(b) Any interest paid on funds in a lease-specific abandonment account will be treated as other funds in the account unless the Regional Director authorizes in writing the payment of interest to the party who deposits the funds.

(c) The Regional Director may allow you to pledge Treasury securities that are made payable upon demand to the Regional Director to satisfy your obligation to make payments into a lease-specific abandonment account.

(d) Before the amount of funds in a lease-specific abandonment account equals the maximum insurable amount as determined by the Federal Deposit Insurance Corporation or the Federal Savings and Loan Insurance Corporation, the institution managing the account must use the funds in the account to purchase Treasury securities pledged to MMS under paragraph (c) of this section. The institution managing the lease specific-abandonment account will join with the Regional Director to establish a Federal Reserve Circular 154 account to hold these Treasury securities, unless the Regional Director authorizes the managing institution to retain the pledged Treasury securities in a separate trust account. You may obtain a copy of the current Treasury Circular No. 154 from the Surety Bond Branch, Financial Management Service, Department of the Treasury, East-West Highway, Hyattsville, MD 20782.

(e) The Regional Director may require you to create an overriding royalty or production payment obligation for the benefit of a lease-specific account pledged for the abandonment and clearance of a lease. The required obligation may be associated with oil and gas or sulphur production from a lease other than the lease bonded through the lease-specific abandonment account.

[62 FR 27957, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27957, May 22, 1997, §256.56 was added, effective Aug. 20, 1997.

§256.57 Using a third-party guarantee instead of a bond.

(a) *When the Regional Director may accept a third-party guarantee.* The Regional Director may accept a third-party guarantee instead of an additional bond under §256.53(d) if:

(1) The guarantee meets the criteria in paragraph (c) of this section;

(2) The guarantee includes the terms specified in paragraph (d) of this section;

(3) The guarantor's total outstanding and proposed guarantees do not exceed 25 percent of its unencumbered net worth in the United States; and

(4) The guarantor submits an indemnity agreement meeting the criteria in paragraph (e) of this section.

(b) *What to do if your guarantor becomes unqualified.* If, during the life of your third-party guarantee, your guarantor no longer meets the criteria of paragraphs (a)(3) and (c)(3) of this section, you must:

(1) Notify the Regional Director immediately; and

(2) Cease production until you comply with the bond coverage requirements of this subpart.

(c) *Criteria for acceptable guarantees.* If you propose to furnish a third party's guarantee, that guarantee must ensure compliance with all lessees' lease obligations, the obligations of all operating rights owners, and the obligations of all operators on the lease. The Regional Director will base acceptance of your third-party guarantee on the following criteria:

(1) The period of time that your third-party guarantor (guarantor) has been in continuous operation as a business entity where:

(i) Continuous operation is the time that your guarantor conducts business immediately before you post the guarantee; and

(ii) Continuous operation excludes periods of interruption in operations that are beyond your guarantor's control and that do not affect your guarantor's likelihood of remaining in business during exploration, development, production, abandonment, and clearance operations on your lease.

(2) Financial information available in the public record or submitted by your guarantor, on your guarantor's own initiative, in sufficient detail to show to the Regional Director's satisfaction that your guarantor is qualified based on:

(i) Your guarantor's current rating for its most recent bond issuance by either Moody's Investor Service or Standard and Poor's Corporation;

(ii) Your guarantor's net worth, taking into account liabilities under its guarantee of compliance with all the terms and conditions of your lease, the regulations in this chapter, and your guarantor's other guarantees;

(iii) Your guarantor's ratio of current assets to current liabilities, taking

into account liabilities under its guarantee of compliance with all the terms and conditions of your lease and the regulations in this chapter and your guarantor's other guarantees; and

(iv) Your guarantor's unencumbered fixed assets in the United States.

(3) When the information required by paragraph (c) of this section is not publicly available, your guarantor may submit the information in the following table. Your guarantor must update the information annually within 90 days of the end of the fiscal year or by the date prescribed by the Regional Director.

The guarantor should submit—	that—
(i) Financial statements for the most recently completed fiscal year.	Include a report by an independent certified public accountant containing the accountant's audit opinion or review opinion of the statements. The report must be prepared in conformance with generally accepted accounting principles and contain no adverse opinion.
(ii) Financial statements for completed quarters in the current fiscal year.	Your guarantor's financial officer certifies to be correct.
(iii) Additional information as requested by the Regional Director.	Your guarantor's financial officer certifies to be correct.

(d) *Provisions required in all third-party guarantees.* Your third-party guarantee must contain each of the following provisions.

(1) If you, your operator, or an operating rights owner fails to comply with any lease term or regulation, your guarantor must either:

(i) Take corrective action; or

(ii) Be liable under the indemnity agreement to provide, within 7 calendar days, sufficient funds for the Regional Director to complete corrective action.

(2) If your guarantor complies with paragraph (d)(1) of this section, this compliance will not reduce its liability.

(3) If your guarantor wishes to terminate the period of liability under its guarantee, it must:

(i) Notify you and the Regional Director at least 90 days before the proposed termination date;

(ii) Obtain the Regional Director's approval for the termination of the period of liability for all or a specified portion of your guarantor's guarantee; and

(iii) Remain liable for all work and workmanship performed during the period that your guarantor's guarantee is in effect.

(4) You must provide a suitable replacement security instrument before the termination of the period of liability under your third-party guarantee.

(e) *Required criteria for indemnity agreements.* If the Regional Director approves your third-party guarantee, the guarantor must submit an indemnity agreement.

(1) The indemnity agreement must be executed by your guarantor and all persons and parties bound by the agreement.

(2) The indemnity agreement must bind each person and party executing the agreement jointly and severally.

(3) When a person or party bound by the indemnity agreement is a corporate entity, two corporate officers who are authorized to bind the corporation must sign the indemnity agreement.

(4) Your guarantor and the other corporate entities bound by the indemnity agreement must provide the Regional Director copies of:

(i) The authorization of the signatory corporate officials to bind their respective corporations;

(ii) An affidavit certifying that the agreement is valid under all applicable laws; and

(iii) Each corporation's corporate authorization to execute the indemnity agreement.

(5) If your third-party guarantor or another party bound by the indemnity agreement is a partnership, joint venture, or syndicate, the indemnity agreement must:

(i) Bind each partner or party who has a beneficial interest in your guarantor; and

(ii) Provide that, upon demand by the Regional Director under your third-party guarantee, each partner is jointly and severally liable for compliance with all terms and conditions of your lease.

(6) When forfeiture is called for under § 256.59 of this part, the indemnity agreement must provide that your guarantor will either:

(i) Bring your lease into compliance; or

(ii) Provide, within 7 calendar days, sufficient funds to permit the Regional Director to complete corrective action.

(7) The indemnity agreement must contain a confession of judgment. It must provide that, if the Regional Director determines that you, your operator, or an operating rights owner is in default of the lease, the guarantor:

(i) Will not challenge the determination; and

(ii) Will remedy the default.

(8) Each indemnity agreement is deemed to contain all terms and conditions contained in this paragraph (e), even if the guarantor has omitted them.

[62 FR 27957, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27957, May 22, 1997, §256.57 was added, effective Aug. 20, 1997.

§256.58 Termination of the period of liability and cancellation of a bond.

This section defines the terms and conditions under which the Regional Director may terminate the period of liability of a bond or cancel a bond.

(a) When the surety under your bond requests termination of the period of liability under its bond, the Regional Director will terminate the period of liability under your bond and demand that you provide a replacement bond of equivalent amount.

(1) Termination of the period of liability under a bond does not release the surety of that bond.

(2) Your surety is responsible for all obligations and liabilities that accrue before the effective date of the Regional Director's termination of the period of liability under its bond.

(b) The Regional Director's cancellation or release of a bond may include lease obligations that accrue before the effective date of the cancellation only when:

(1) The Regional Director determines that there are no outstanding obligations; or

(2) You furnish a replacement bond:

(i) In which your new surety agrees to assume all outstanding liabilities under the bond that is to be canceled; and

(ii) That is in an amount equal to or greater than the amount of the bond that is to be canceled.

(c) The Regional Director will issue a written instrument to cancel or release your bond. This instrument will subject the bond to automatic reinstatement, as if no cancellation or release had occurred, if:

(1) A person makes a payment under the lease and the payment is rescinded or must be repaid by the recipient because the person making the payment is insolvent, bankrupt, subject to reorganization, or placed in receivership; or

(2) The responsible party represents to MMS that it has discharged its obligations under the lease and the representation is materially false when the bond is canceled, or released.

[62 FR 27958, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27958, May 22, 1997, §256.58 was added, effective Aug. 20, 1997.

§256.59 Forfeiture of bonds and/or other securities.

This section explains how a bond or other security may be forfeited.

(a) The Regional Director will call for forfeiture of all or part of the bond, other form of security, or guarantee you provide under this part if:

(1) You (the party who provided the bond) refuse, or the Regional Director determines that you are unable, to comply with any term or condition of your lease; or

(2) You default under one of the conditions under which the Regional Director accepts your bond, third-party guarantee, and/or other form of security.

(b) The Regional Director may pursue forfeiture of your bond without first making demands for performance against any lessee, operating rights owner, or other person authorized to perform lease obligations.

(c) The Regional Director will:

(1) Notify you, the surety on your bond or other form of security, and any third-party guarantor, of his/her determination to call for forfeiture of the bond, security, or guarantee under this section.

(i) This notice will be in writing and will provide the reasons for the forfeiture and the amount to be forfeited.

(ii) The Regional Director must base the amount he/she determines is forfeited upon his/her estimate of the total cost of corrective action to bring your lease into compliance.

(2) Advise you, your third-party guarantor, and any surety, that you, your guarantor, and any surety may avoid forfeiture if, within 5 working days:

(i) You agree to, and demonstrate that you will, bring your lease into compliance within the timeframe that the Regional Director prescribes;

(ii) Your third-party guarantor agrees to, and demonstrates that it will, complete the corrective action to bring your lease into compliance within the timeframe that the Regional Director prescribes; or

(iii) Your surety agrees to, and demonstrates that it will, bring your lease into compliance within the timeframe that the Regional Director prescribes, even if the cost of compliance exceeds the face amount of the bond or other surety instrument.

(d) If the Regional Director finds you are in default, he/she may cause the forfeiture of any bonds and other security deposited as your guarantee of compliance with the terms and conditions of your lease and the regulations in this chapter.

(e) If the Regional Director determines that your bond and/or other security is forfeited, the Regional Director will:

(1) Collect the forfeited amount; and

(2) Use the funds collected to bring your leases into compliance and to correct any default.

(f) If the amount the Regional Director collects under your bond and other security is insufficient to pay the full cost of corrective actions he/she may:

(1) Take or direct action to obtain full compliance with your lease and the regulations in this chapter; and

(2) Recover from you, any co-lessee, operating rights owner, and/or any third-party guarantor responsible under this subpart all costs in excess of the amount he/she collects under your forfeited bond and other security.

(g) The amount that the Regional Director collects under your forfeited bond and other security may exceed the costs of taking the corrective actions required to obtain full compliance with the terms and conditions of your lease and the regulations in this chapter. In this case, the Regional Director will return the excess funds to the party from whom they were collected.

[62 FR 27958, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27958, May 22, 1997, § 256.59 was added, effective Aug. 20, 1997.

Subpart J—Assignments, Transfers, and Extensions

§ 256.62 Assignment of lease or interest in lease.

This section explains how to assign record title and other interests in OCS oil and gas or sulphur leases.

(a) MMS may approve the assignment to you of the ownership of the record title to a lease or any undivided interest in a lease, or an officially designated subdivision of a lease, only if:

(1) You qualify to hold a lease under § 256.35(b);

(2) You provide the bond coverage required under subpart I of this part; and

(3) The Regional Director approves the assignment.

(b) An assignment shall be void if it is made pursuant to any prelease agreement described in § 256.44(c) of this part that would cause a bid to be disqualified.

(c) Any approved assignment shall be deemed to be effective on the first day of the lease month following its filing in the appropriate office of the MMS, unless at the request of the parties, an earlier date is specified in the approval.

(d) You, as assignor, are liable for all obligations that accrue under your lease before the date that the Regional Director approves your request for assignment of the record title in the lease. The Regional Director's approval of the assignment does not relieve you of accrued lease obligations that your assignee, or a subsequent assignee, fails to perform.

(e) Your assignee and each subsequent assignee are liable for all obligations that accrue under the lease after the date that the Regional Director approves the governing assignment. They must:

(1) Comply with all the terms and conditions of the lease and all regulations issued under the Act; and

(2) Remedy all existing environmental problems on the tract, properly abandon all wells, and reclaim the lease site in accordance with part 250, subpart G.

(f) If your assignee, or a subsequent assignee, fails to perform any obligation under the lease or the regulations in this chapter, the Regional Director may require you to bring the lease into compliance to the extent that the obligation accrued before the Regional Director approved the assignment of your interest in the lease.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982, and amended at 58 FR 45262, Aug. 27, 1993; 62 FR 27959, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27959, May 22, 1997, §256.62 was amended by revising the section heading, adding introductory text, revising paragraphs (a), (d), and (e), and adding paragraph (f), effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§256.62 Assignment of leases or interests therein.

(a) Subject to the approval of the authorized officer, leases, or any undivided interest therein, may be assigned in whole, or as to any officially designated subdivision, to anyone qualified under §256.35(b) of this part to hold a lease.

* * * * *

(d) The assignor shall be liable for all obligations under the lease accruing prior to the approval of the assignment.

(e) The assignee shall be liable for all obligations under the lease subsequent to the effective date of an assignment, and shall comply with all regulations issued under the act including the requirements to furnish any surety bonds as specified in OCS leases and §§256.58 and 256.61 of this part.

§256.64 How to file transfers.

This section explains how to file instruments with MMS that create and/or transfer interests in OCS oil and gas or sulphur leases.

(a) You must submit to the Regional Director for approval all instruments that create or transfer ownership of a lease interest.

(1) You must submit two copies of the instruments that create or transfer an interest. Each instrument that creates or transfers an interest must describe by officially designated subdivision the interest you propose to create or transfer.

(2) You must submit your proposal to create or transfer an interest, or create or transfer separate operating rights, subleases, and record title interests within 90 days of the last date that a party executes the transfer agreement.

(3) The transferee must meet the citizenship and other qualification criteria specified in §256.35 of this part. When you submit an instrument to create or transfer an interest as an association, you must include a statement signed by the transferee about the transferee's citizenship and qualifications to own a lease.

(4) Your instrument to create or transfer an interest must contain all of the terms and conditions to which you and the other parties agree.

(5) You do not gain a release of any nonmonetary obligation under your lease or the regulations in this chapter by creating a sublease or transferring operating rights.

(6) You do not gain a release from any accrued obligation under your lease or the regulations in this chapter by assigning your record title interest in the lease.

(7) You may create or transfer carried working interests, overriding royalty interests, or payments out of production without obtaining the Regional Director's approval. However, you must file instruments creating or transferring carried working interests, overriding royalty interests, or payments out of production with the Regional Director for record purposes.

(8) An application for approval of any instrument required to be filed shall not be accepted unless accompanied by a nonrefundable fee of $25. Any document not required to be filed by these regulations but submitted for record purposes shall be accompanied by a nonrefundable fee of $25 per lease affected. Such documents may be rejected at the discretion of the authorized officer.

(b) An attorney in fact, in behalf of the holder of a lease, operating rights or sublease, shall furnish evidence of authority to execute the assignment or

application for approval and the statement required by § 256.46 of this part.

(c) When you request approval for an assignment that assigns all your record title interest in a lease or that creates a segregated lease, your assignee must furnish a bond in the amount prescribed in §§ 256.52 and 256.53 of this part.

(d) When you request approval for an assignment that assigns less than all the record title of a lease and that does not create a separate lease, the assignee may, with the surety's consent, become a joint principal on the surety instrument that guarantees compliance with all the terms and conditions of the lease.

(e) An heir or devisee of a deceased holder of a lease, or any interest therein, shall be recognized as the lawful successor to such lease or interest, if evidence of status as an heir or devisee is furnished in the form of:

(1) A certified copy of an appropriate order or decree of the court having jurisdiction of the distribution of the estate or,

(2) If no court action is necessary, the statements of two disinterested parties having knowledge of the facts or a certified copy of the will.

(f) In addition to the requirements of paragraph (d) of this section, the heirs or devisees shall file statements that they are the persons named as successors to the estate with evidence of their qualifications as provided in § 256.46 of this part.

(g) In the event an heir or devisee is unable to qualify to hold the lease or interest, the heir or devisee shall be recognized as the lawful successor of the deceased and be entitled to hold the lease for a period of not to exceed 2 years from the date of death of the predecessor in interest.

(h) Your heirs, executors, administrators, successors, and assigns are bound to comply with each obligation under any lease and under the regulations in this chapter.

(1) You are jointly and severally liable for the performance of each nonmonetary obligation under the lease and under the regulations in this chapter with each prior lessee and with each operating rights owner holding an interest at the time the obligation accrued, unless this chapter provides otherwise.

(2) Sublessees and operating rights owners are jointly and severally liable for the performance of each nonmonetary obligation under the lease and under the regulations in this chapter to the extent that:

(i) The obligation relates to the area embraced by the sublease;

(ii) Those owners held their respective interest at the time the obligation accrued; and

(iii) This chapter does not provide otherwise.

(i) Where the proposed assignment or transfer is by a person who, at the time of acquisition of an interest in the lease, was on the List of Restricted Joint Bidders, and that assignment or transfer is of less than the entire interest of the assignor or transferor, to a person or persons on the same List of Restricted Joint Bidders, the assignor or transferor shall file a copy, prior to approval of the assignment, of all agreements applicable to the acquisition of that lease or a fractional interest.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 62 FR 27959, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27959, May 22, 1997, § 256.64 was amended by revising the section heading, adding introductory text and paragraph (a) introductory text, redesignating paragraph (a)(2) as (a)(8), adding new paragraphs (a)(2) through (a)(7), redesignating paragraphs (d) through (h) as (e) through (i), revising paragraphs (c) and redesignated paragraph (h), and adding a new paragraph (d), effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 256.64 Requirements for filing of transfers.

(a)(1) All instruments of transfer of a lease or of an interest therein as to any officially designated subdivision, including operating rights, subleases and assignments of record interest, shall be filed in triplicate for approval within 90 days from the date of final execution. They shall include a statement over the transferee's own signature with respect to citizenship and qualifications similar to that required of a lessee and shall contain all of the terms and conditions agreed upon by the parties thereto. Carried working interests, overriding royalty interests or payments out of production may be created

or transferred without requirement for filing or approval.

* * * * *

(c) Where an assignment creates a segregated lease, a bond shall be furnished in the amount prescribed in § 256.58 of this part. Where an assignment does not create separate leases, the assignee, if the assignment so provides and the surety consents, may become a joint principal on the bond with the assignor.

* * * * *

(g) Each obligation under any lease and under the regulations in this part shall inure to the heirs, executors, administrators, successors, or assignees of the lessee.

* * * * *

§ 256.65 Attorney General review.

Prior to the approval of an assignment or transfer, the Secretary shall consult with and give due consideration to the views of the Attorney General. The Secretary may act on an assignment or transfer if the Attorney General has not responded to the request for consultation within 30 days of said request.

§ 256.67 Separate filings for assignments.

A separate instrument of assignment shall be filed for each lease. When transfers to the same person, association or corporation, involving more than one lease are filed at the same time for approval, one request for approval and one showing as to the qualifications of the assignee shall be sufficient.

§ 256.68 Effect of assignment of a particular tract.

(a) When an assignment is made of all the record title to a portion of the acreage in a lease, the assigned and retained portions become segregated into separate and distinct leases. In such a case, the assignee becomes a lessee of the Government as to the segregated tract that is the subject of assignment, and is bound by the terms of the lease as though the lease had been obtained from the United States in the assignee's own name, and the assignment, after its approval, shall be the basis of a new record. Royalty, minimum royalty and rental provisions of the original lease shall apply separately to each segregated portion.

(b) For assignments of a portion of an oil and gas lease approved after the effective date of ths section, each segregated lease shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil or gas is produced from that segregated portion of the leased area in paying quantities or drillng or well reworking operations as approved by the Secretary are conducted.

(c) For those assignments approved prior to the effective date of this section, each segregated lease shall continue in full force and effect for the primary term of the original lease and so long thereafter as oil and gas may be produced from the original leased area in paying quantities or drilling or well reworking operations, as approved by the Secretary, are conducted.

§ 256.70 Extension of lease by drilling or well reworking operations.

The term of a lease shall be extended beyond the primary term so long as drilling or well reworking operations are approved by the Secretary according to the conditions set forth in 30 CFR 250.13.

[44 FR 38276, June 29, 1979, as amended at 55 FR 32908, Aug. 13, 1990]

§ 256.71 Directional drilling.

In accordance with an approved exploration plan or development and production plan, a lease may be maintained in force by directional wells drilled under the leased area from surface locations on adjacent or adjoining land not covered by the lease. In such circumstances, drilling shall be considered to have commenced on the leased area when drilling is commenced on the adjacent or adjoining land for the purpose of directional drilling under the leased area through any directional well surfaced on adjacent or adjoining land. Production, drillling or reworking of any such directional well shall be considered production or drilling or reworking operations on the leased area for all purposes of the lease.

§ 256.72 Compensatory payments as production.

If an oil and gas lessee makes compensatory payments and if the lease is not being maintained in force by other production of oil or gas in paying quantities or by other approved drilling or reworking operations, such payments shall be considered as the equivalent of production in paying quantities for all purposes of the lease.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982, and amended at 54 FR 50617, Dec. 8, 1989]

§ 256.73 Effect of suspensions on lease term.

(a) If the Regional Supervisor directs the suspension of either operations or production, or both, under the provisions of 30 CFR 250.10 (a), (b)(2) through (b)(7), or (c) with respect to any lease in its primary term, the primary term of the lease shall be extended by a period equivalent to the period of the suspension.

(b) If the Regional Supervisor orders or approves the suspension of either operations or production, or both, under the provision for 30 CFR 250.10 (a), (b)(2) through (b)(7), or (c) with respect to any lease extended beyond its primary term, the term of the lease shall not be deemed to expire so long as the suspension remains in effect.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979. Redesignated at 47 47006, Oct. 22, 1982, and amended at 54 FR 50617, Dec. 8, 1989]

Subpart K—Termination of Leases

§ 256.76 Relinquishment of leases or parts of leases.

A lease or any officially designated subdivision thereof may be surrendered by the record title holder by filing a written relinquishment, in triplicate, with the appropriate OCS office of the MMS. No filing fee is required. A relinquishment shall take effect on the date it is filed subject to the continued obligation of the lessee and the surety to make all payments due, including any accrued rentals, royalties and deferred bonuses and to abandon all wells and condition or remove all platforms and other facilities on the land to be relinquished to the satisfaction of the Director.

§ 256.77 Cancellation of leases.

(a) Any nonproducing lease issued under the act may be cancelled by the authorized officer whenever the lessee fails to comply with any provision of the act or lease or applicable regulations, if such failure to comply continues for 30 days after mailing of notice by registered or certified letter to the lease owner at the owner's record post office address. Any such cancellation is subject to judicial review as provided in section 23(b) of the Act.

(b) Producing leases issued under the Act may be cancelled by the Secretary whenever the lessee fails to comply with any provision of the Act, applicable regulations or the lease only after judicial proceedings as prescribed by section 5(d) of the Act.

(c) Any lease issued under the Act, whether producing or not, shall be canceled by the authorized officer upon proof that it was obtained by fraud or misrepresentation, and after notice and opportunity to be heard has been afforded to the lessee.

(d) Pursuant to section 5(a) of the Act, the Secretary may cancel a lease when:

(1) Continued activity pursuant to such lease would probably cause serious harm or damage to life, property, any mineral, national security or defense, or to the marine, coastal or human environment;

(2) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(3) The advantages of cancellation outweigh the advantages of continuing such lease or permit in force. Procedures and conditions contained in 30 CFR 250.12 shall apply as appropriate.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982]

Subpart L—Section 6 Leases

§ 256.79 Effect of regulations on lease.

(a) All regulations in this part, insofar as they are applicable, shall supersede the provisions of any lease which is maintained under section 6(a) of the

Act. However, the provisions of a lease relating to area, minerals, rentals, royalties (subject to sections 6(a) (8) and (9) of the Act), and term (subject to section 6(a)(10) of the Act and, as to sulfur, subject to section 6(b)(2) of the Act) shall continue in effect, and, in the event of any conflict or inconsistency, shall take precedence over these regulations.

(b) A lease maintained under section 6(a) of the Act shall also be subject to all operating and conservation regulations applicable to the OCS. In addition, the regulations relating to geophysical and geological exploratory operations and to pipeline rights-of-way are applicable, to the extent that those regulations are not contrary to or inconsistent with the lease provisions relating to area, the minerals, rentals, royalties and term. The lessee shall comply with any provision of the lease as validated, the subject matter of which is not covered in the regulations in this part.

[44 FR 38276, June 29, 1979; 44 FR 55380, Sept. 26, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982]

§ 256.80 Leases of other minerals.

The existence of a lease that meets the requirements of section 6(a) of the Act shall not preclude the issuance of other leases of the same area for deposits of other minerals. However, no other lease of minerals shall authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease. No sulphur leases shall be granted by the United States on any area while such area is included in a lease covering sulphur under section 6(b) of the Act.

Subpart M—Studies

§ 256.82 Environmental studies.

(a) The Director shall conduct a study of any area or region included in any lease sale in order to establish information needed for assessment and management of impacts on the human, marine and coastal environments which may be affected by OCS oil and gas activities in such area or region. Any study shall, to the extent practicable, be designed to predict environmental impacts of pollutants introduced into the environments and of the impacts of offshore activities on the seabed and affected coastal areas.

(b) Studies shall be planned and carried out in cooperation with the affected States and interested parties and, to the extent possible, shall not duplicate studies done under other laws. Where appropriate, the Director shall, to the maximum extent practicable, enter into agreements with the National Oceanic and Atmospheric Administration in executing the environmental studies responsibilities. By agreement, the Director may also utilize services, personnel or facilities of any Federal, State or local government agency in the conduct of such study.

(c) Any study of an area or region required by paragraph (a) of this section for a lease sale shall be commenced not later than six months prior to holding a lease sale for that area. The Director may utilize information collected in any prior study. The Director may initiate studies for areas or regions not identified in the leasing program.

(d) After the leasing and developing of any area or region, the Director shall conduct such studies as are deemed necessary to establish additional information and shall monitor the human, marine and coastal environments of such area or region in a manner designed to provide information which can be compared with the results of studies conducted prior to OCS oil and gas development. This shall be done to identify any significant changes in the quality and productivity of such environments, to establish trends in the areas studies, and to design experiments identifying the causes of such changes. Findings from such studies shall be used to recommend modifications in practices which are employed to mitigate the effects of OCS activities and to enhance the data/information base for predicting impacts which might result from a single lease sale or cumulative OCS activities.

(e) Information available or collected by the studies program shall, to the extent practicable, be provided in a form and in a timeframe that can be used in the decision-making process associated with a specific leasing action or with

longer term OCS minerals management responsibilities.

APPENDIX A TO PART 256—OIL AND GAS CASH BONUS BID

The following bid is submitted for an oil and gas lease on the area of the Outer Continental Shelf specified below:

Tract No.*	Total amount bid	Amount per acre (or per hectare)	Amount of cash submitted with bid

*Or, if tract numbers are not used, Protraction Diagram or Leasing Map and block number.

Bidder qualification No.	Proportionate interest of company(s) submitting bid	Name and address of bidding company
—— Misc. No.	.....	

_____,
Authorized signatory's name and title.

[47 FR 25972, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982]

PART 259—MINERAL LEASING: DEFINITIONS

Sec.
259.001 Purpose and scope.
259.002 Definitions.

AUTHORITY: Pub. L. 83–212, 67 Stat. 462, 43 U.S.C. 1331 *et seq.*, as amended by Pub. L. 95–372, 92 Stat. 629.

§ 259.001 Purpose and scope.

The purpose of this part 259 is to define various terms appearing in parts 260, 261 and 262 of this chapter.

[48 FR 1182, Jan. 11, 1983]

§ 259.002 Definitions.

For purposes of parts 260, 261, and 262 of this chapter:

Area or *region* means the geographic area or region over which the MMS designated official has jurisdiction, unless the context in which those words are used indicates that a different meaning is intended.

Designated official means a representative of DOI subject to the direction and supervisory authority of the Director, MMS, and the appropriate Regional Manager of the MMS authorized and empowered to supervise and direct all oil and gas operations and to perform other duties prescribed in 30 CFR part 250 (offshore).

Director means Director, MMS, DOI.

DOI means the Department of the Interior, including the Secretary of the Interior, or his or her delegate.

Federal lease means an agreement which, for any consideration, including, but not limited to, bonuses, rents or royalties conferred, and convenants to be observed, authorizes a person to explore for, or develop, or produce (or to do any or all of these) oil and gas, coal, oil shale, tar sands, and goethermal resources on lands or interests in lands under Federal jurisdiction.

Gas means natural gas as defined by the Federal Energy Regulatory Commission.

MMS means Minerals Management Service.

OCS means the Outer Continental Shelf, which includes all submerged lands (1) that lie seaward outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (Pub. L. 31–35, 67 Stat. 29, (43 U.S.C. 1301)) and (2) of which the subsoil and seabed appertain to the United States are subject to its jurisdiction and control.

OCSLA means the Outer Continental Shelf Lands Act, as amended (Act of August 7, 1953, Ch. 345, 67 Stat. 462, 43 U.S.C. 1331 *et seq.*, as amended by Pub. L. 95–372, 92 Stat. 629).

Oil means a mixture of hydrocarbons that exists in a liquid or gaseous phase in an underground reservoir and which remains or becomes liquid at atmospheric pressure after passing through surface separating facilities, including condensate recovered by means other than a manufacturing process.

[48 FR 1182, Jan. 11, 1983]

PART 260—OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Subpart A—General Provisions

Sec.
260.001 Purpose and scope.

260.002 Definitions.

Subpart B—Bidding Systems

260.101 Purpose and scope.
260.102 Definitions.
260.110 Bidding systems.
260.111 Criteria for selection of bidding systems and bidding system components.

Subpart C [Reserved]

Subpart D—Joint Bidding

260.301 Purpose.
260.302 Definitions.
260.303 Joint bidding requirements.

AUTHORITY: 43 U.S.C. 1331 and 1337.

SOURCE: 45 FR 9539, Feb. 12, 1980, unless otherwise noted. Redesignated at 48 FR 1182, Jan. 11, 1983.

Subpart A—General Provisions

§ 260.001 Purpose and scope.

The purpose of this part 260 is to implement OCSLA, 43 U.S.C. 1331 *et seq.*, as amended, by providing regulations to foster competition including, but not limited to, regulations to prohibit joint bidding for development rights by certain types of joint ventures; the implementation of alternative bidding systems (including suspension of royalties for a period, volume, or value of production); and the establishment of diligence requirements for Federal OCS leases issued under the OCSLA.

[61 FR 3804, Feb. 2, 1996]

§ 260.002 Definitions.

For purposes of this part 260:

OCSLA means the Outer Continental Shelf Lands Act, (43 U.S.C. 1331 *et seq.*), as amended.

OCS lease means a Federal lease for oil and gas issued under the OCSLA.

Person includes, in addition to a natural person, an association, a State, or a private, public, or municipal corporation.

[45 FR 9539, Feb. 12, 1980. Redesignated at 48 FR 1182, Jan. 11, 1983, as amended at 61 FR 3804, Feb. 2, 1996]

Subpart B—Bidding Systems

§ 260.101 Purpose and scope.

(a) This subpart establishes the several bidding systems that may be utilized in connection with the offering and sale of Federal leases for the exploration, development and production of oil and gas resources located on the OCS.

(b) Only bidding systems established by his subpart shall be utilized in OCS lease sales.

§ 260.102 Definitions.

For purposes of this subpart B—

Eligible lease means a lease that results from a sale held after November 28, 1995; is located in the Gulf of Mexico in water depths 200 meters or deeper; lies wholly west of 87 degrees, 30 minutes west longitude; and is offered subject to a royalty suspension volume authorized by statute.

Field means an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Highest responsible qualified bidder means a person who has met the appropriate requirements of 30 CFR part 256, subpart G and has submitted a bid higher than any other bids by qualified bidders on the same tract.

Highest royalty rate means the highest per centum rate payable to the United States, as specified in the lease, in amount or value of the production saved, removed or sold.

Lowest royalty rate means the lowest per centum rate payable to the United States, as specified in the lease, in amount or value of the production saved, removed or sold.

OCS lease sale means the DOI proceeding by which leases for certain OCS tracts are offered for sale by competitive bidding and during which bids are received, announced and recorded.

Production period means the period during which the amount of oil and gas produced from a tract, or, if the tract is unitized, the amount of oil and gas as allocated under a unitization formula, will be measured for purposes of determining the amount of royalty payable to the United States.

Qualified bidder means a person, who has met the appropriate requirements of 30 CFR part 256, subpart G.

Tract means a designation assigned solely for administrative purposes to a block or combination of blocks that are identified by a leasing map or an official protraction diagram prepared by DOI.

Value of production means the value of all oil and gas production saved, removed or sold from a tract, or, if the tract is unitized, the value of all oil and gas production saved, removed or sold and credited to the tract under a unitization formula, during a production period, which value is determined in accordance with § 260.110(b).

[45 FR 9539, Feb. 12, 1980. Redesignated at 48 FR 1182, Jan. 11, 1983, as amended at 61 FR 12027, Mar. 25, 1996]

§ 260.110 Bidding systems.

(a) A single bidding system selected from those listed in this paragraph shall be applied to each tract included in an OCS lease sale.

(1) *Cash bonus bid with a fixed royalty rate of not less than 12½ per centum in amount or value of the production saved, removed or sold and an annual rental.* (i) The royalty rate to be paid by the highest responsible qualified bidder shall be a percentage of the amount or value of the production saved, removed or sold. Such royalty rate shall not be less than 12½ per centum at the beginning of the lease period in amount or value of production and shall be specified in the notice of OCS lease sale published in the FEDERAL REGISTER.

(ii) The amount of cash bonus to be paid is determined by the qualified bidder submitting the bid. Any deferment and the schedule of payments shall be included in the notice of OCS lease sale published in the FEDERAL REGISTER.

(iii) The annual rental to be paid by the highest responsible qualified bidder and any amounts creditable against future royalties shall be specified in the notice of sale published in the FEDERAL REGISTER.

(2) *Royalty rate bid based on per centum in amount or value of the production saved, removed or sold, with a fixed cash bonus and an annual rental.* (i) The royalty rate to be paid is determined by the qualified bidder submitting the bid and shall be based on a percentage of the amount or value of the production saved, removed, or sold.

(ii) The cash bonus to be paid by the highest responsible qualified bidder shall be an amount specified in the notice of OCS lease sale published in the FEDERAL REGISTER.

(iii) Rental payment amounts must be as specified in paragraph (a)(1)(iii) of this section.

(3) *Cash bonus bid with diminishing or sliding royalty rate of not less than 12½ per centum at the beginning of the lease period in amount or value of the production saved, removed, or sold, and annual rental.* (i)(A) The royalty rate to be paid by the highest responsible qualified bidder shall be a percentage of the amount or value of the production saved, removed or sold. The royalty rate shall be calculated by utilizing either a sliding scale formula, which relates the royalty rate established thereby to the adjusted value of the oil and gas produced during the production period, or a schedule that establishes the royalty rate that will be applied to specified ranges of adjusted value of production. The description of the sliding scale formula or schedule shall include the relationship between adjusted value of production and royalty rate, and a stipulation of the lowest royalty rate and highest royalty rate. The sliding scale formula or schedule shall be included in the lease issued to the person who is the successful bidder as one of the lease terms and conditions.

(B) The royalty rate shall not be less than 12½ per centum at the beginning of the lease period in amount or value of the production saved, removed or sold and shall be specified in the notice of OCS lease sale published in the FEDERAL REGISTER.

(C) *Royalty payment calculation.* (*1*) The royalty rate utilized in the calculation of royalty payments is based on an adjusted value of production, and is established through application of a sliding scale formula or a schedule to the adjusted value of production.

(*2*) The adjusted value of production shall be determined by applying an inflation factor to the actual value of production.

(*3*) The established royalty rate is applied to the actual value of production, which results in the determination of amount in dollars to be paid to the United States by the person awarded the lease or the amount of royalty oil and gas to be taken in kind by the United States.

(*4*) The production period, inflation factor and procedures for making the inflation adjustment and for determining the value or amount of production shall be stated in the notice of sale published in the FEDERAL REGISTER.

(ii) The amount of cash bonus to be paid is determined by the qualified bidder submitting the bid. Any deferment and the schedule of payments shall be included in the notice of OCS lease sale published in the FEDERAL REGISTER.

(iii) Rental payment amounts must be as specified in paragraph (a)(1)(iii) of this section.

(4) *Cash bonus bid with a fixed share of the net profits of no less than 30 per centum to be derived from the production of oil and gas from the lease area and a fixed annual rental*—(i) *Net profit share payment calculation.* The amount of the net profit share payment to the United States by the person awarded the lease shall be determined for each month by multiplying the net profit share base times the net profit share rate, in accordance with § 220.022.

(A) *Net profit share base.* (1) The net profit share base shall be calculated in accordance with § 220.021.

(2) The capital recovery factor needed to calculate the allowance for capital recovery, in accordance with § 220.020, shall be specified in the notice of OCS lease sale published in the FEDERAL REGISTER and may vary from tract to tract.

(B) *Net profit share rate.* The net profit share rate, which determines the fixed share of the net profits owed to the United States, shall be a percentage that is specified in the notice of OCS lease sale published in the FEDERAL REGISTER. Such net profit share rate shall not be less than 30 percent of the net profit share base and may vary from tract to tract.

(ii) The amount of cash bonus to be paid is determined by the person submitting the bid. Any deferment and the schedule of payments shall be included in the notice of OCS lease sale published in the FEDERAL REGISTER.

(iii) The annual rental to be paid by the person awarded the lease shall be the amount specified in the notice of OCS lease sale published in the FEDERAL REGISTER.

(5) *Cash bonus bid with a variable royalty rate or rates during one or more production periods in amount or value of the production saved, removed or sold, and an annual rental.* MMS may suspend or defer the royalty due for a period, volume, or value of production. Such suspensions or deferrals may vary based on changes in the prices of oil and/or gas as specified in the notice of sale published in the FEDERAL REGISTER.

(i) The royalty rate due on production may be less than 12½ per centum, but greater than zero per centum, at any designated time during the lease period based on the amount or value of production saved, removed, or sold. Royalty may be suspended or deferred for a period, volume, or value of production. The applicable royalty rate(s) and suspension or deferral magnitudes or formulas shall be specified in the notice of sale published in the FEDERAL REGISTER.

(ii) The amount and the procedure for payment of a cash bonus must be as specified in paragraph (a)(1)(ii) of this section.

(iii) Rental payment amounts must be as specified in paragraph (a)(1)(iii) of this section.

(6) *Cash bonus bid with a royalty rate or rates based on formula(s) or schedule(s) during one or more production periods in amount or value of the production saved, removed or sold, and an annual rental.* Royalty may be suspended or deferred for a period, volume, or value of production. Such a suspension or deferral may vary based on changes in the prices of oil and/or gas as specified in the notice of sale published in the FEDERAL REGISTER.

(i) The royalty due on production shall be specified as a percentage of the amount or value of the production saved, removed, or sold. When the value of production is used, by unit or in aggregate, the royalty rate will be determined based on prices for oil and/or gas as specified in the notice of sale published in the FEDERAL REGISTER.

(A) The lessee must calculate the royalty due using the formula or schedule specified in the lease based on the adjusted amount or indexed value of the oil and gas produced. The formula or schedule will describe the relationship between the adjusted or actual amount of production, indexed value, or indexed price, and the royalty rate. It will stipulate the lowest and highest royalty rates.

(B) The royalty rate formula or schedule and the suspension or deferral magnitudes or formulas shall be specified in the notice of sale published in the FEDERAL REGISTER.

(C) *Royalty payment calculation.*

(*1*) The royalty rate used to calculate the royalty due on production is based on an adjusted or actual amount of production, indexed value, or indexed price and is set through application of the specified formula or schedule to the designated production period.

(*2*) The lessee will determine the adjusted amount or indexed value, or indexed price by applying an index or inflation factor specified in the lease to the actual amount or value of production, or to the adjusted price.

(*3*) The lessee must apply the royalty rate to the actual value of production. The result is the amount in dollars that the lessee must pay to the United States, or the amount of royalty oil and/or gas that the United States will take in kind.

(*4*) The production period, inflation factor and procedures for making the inflation adjustment and for determining the value or amount of production shall be stated in the notice of sale published in the FEDERAL REGISTER.

(ii) The amount and the procedure for payment of a cash bonus must be as specified in paragraph (a)(1)(ii) of this section.

(iii) Rental payment amounts must be as specified in paragraph (a)(1)(iii) of this section.

(7) *Cash bonus bid with a royalty rate of not less than 12½ per centum fixed in amount or value of the production saved, removed or sold, and with suspension of royalties for a period, volume, or value of production, and an annual rental.* Royalty may be suspended for a period, volume, or value of production. Such a suspension may vary based on changes in the prices of oil and/or gas as specified in the notice of sale published in the FEDERAL REGISTER.

(i) Except for a period of suspension, the royalty rate due on production will be specified as a percentage of the amount or value of the production saved, removed, or sold. The applicable royalty rate shall be specified in the notice of the lease sale published in the FEDERAL REGISTER. When the royalty rate is applied to the value of production, by unit or in aggregate, the royalty rate will be determined based on the prices for oil and/or gas as specified in the notice of sale published in the FEDERAL REGISTER.

(A) The lessee must calculate the royalty due using the formula or schedule specified in the lease agreement based on the adjusted amount or indexed value of the oil and gas produced. The formula or schedule will describe the relationship between adjusted or actual amount of production, indexed value, or indexed price, and the royalty rate. It will stipulate the lowest and highest royalty rates that may apply.

(B) The formula or schedule for royalty due on production and the suspension magnitudes or formulas shall be specified in the notice of sale published in the FEDERAL REGISTER.

(ii) The amount and the procedure for payment of a cash bonus must be as specified in paragraph (a)(1)(ii) of this section.

(iii) Rental payment amounts must be as specified in paragraph (a)(1)(iii) of this section.

(b) The value basis for determining the actual value of production and for purposes of computing royalty in accordance with the bidding systems established by paragraph (a) of this section shall be as described in 30 CFR 206.102, 206.152, and 206.153; *Provided, however,* That with respect to oil, the first sale of which is controlled under 10 CFR part 212, the value shall not exceed the lawful first sale price of such oil; and *Provided further,* That with respect to gas, the value shall not exceed the sale price established by the Federal Energy Regulatory Commission.

(c) MMS may, by rule, add to or modify the bidding systems listed in paragraph (a) of this section, in accordance with the procedural requirements of

OCSLA, 43 U.S.C. 1331 *et seq.*, as amended by Pub. L. 95–372, 92 Stat. 629.

(d) This paragraph explains how the royalty suspension volumes in section 304 of the Outer Continental Shelf Deep Water Royalty Relief Act, Pub. L. 104–58, apply to eligible leases. For purposes of this paragraph, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter do not count against royalty suspension volumes. Also, for the purposes of this paragraph, production includes volumes allocated to a lease under an approved unit agreement.

(1) Your eligible lease may receive a royalty suspension volume only if your lease is in a field where no current lease produced oil or gas (other than test production) before November 28, 1995. Paragraph (d) of this section applies only to eligible leases in fields meeting this condition.

(2) The Final Notice of Sale will specify the water depth for each eligible lease. Our determination of water depth for each lease is final once we issue the lease. The Notice also will specify the royalty suspension volume applicable to each water depth. The minimum royalty suspension volumes for fields are:

(i) 17.5 mmboe in 200 to 400 meters of water;

(ii) 52.5 mmboe in 400 to 800 meters of water; and

(iii) 87.5 mmboe in more than 800 meters of water.

(3) When production (other than test production) first occurs from any of the eligible leases in a field, we will determine what royalty suspension volume applies to the eligible lease(s) in that field. The determination is based on the royalty suspension volumes specified in paragraph (d)(2) of this section.

(4) If a new field consists of eligible leases in different water depth categories, the royalty suspension volume associated with the deepest eligible lease applies.

(5) If your eligible lease is the only eligible lease in a field, you do not owe royalty on the production from your lease up to the applicable royalty suspension volume.

(6) If a field consists of more than one eligible lease, payment of royalties on the eligible leases' initial production is suspended until their cumulative production equals the field's established royalty suspension volume. The royalty suspension volume for each eligible lease is equal to each lease's actual production (or production allocated under an approved unit agreement) until the field's established royalty suspension volume is reached.

(7) If an eligible lease is added to a field that has an established royalty suspension volume, the field's royalty suspension volume will not change even if the added lease is in deeper water. The additional lease may receive a royalty suspension volume only to the extent of its production before the cumulative production from all eligible leases in the field equals the field's previously established royalty suspension volume.

(8) If we reassign a well on an eligible lease to another field, the past production from that well will count toward the royalty suspension volume, if any, specified for the new field to which it is assigned. The past production will not be counted toward the suspension volume, if any, from the first field.

(9) You may receive a royalty suspension volume only if your entire lease is west of 87 degrees, 30 minutes west longitude. A field that lies on both sides of this meridian will receive a royalty suspension volume only for those eligible leases lying entirely west of the meridian.

(10) Your lease may obtain more than one royalty suspension volume. If a new field is discovered on your eligible lease that already benefits from the royalty suspension volume for another field, production from that new field receives a separate royalty suspension.

(11) You must measure natural gas production subject to the royalty suspension volume as follows: 5.62 thousand cubic feet of natural gas equals

one barrel of oil equivalent, as measured at 15.025 psi, 60 degrees Fahrenheit, and fully saturated.

[45 FR 9539, Feb. 12, 1980, as amended at 45 FR 36800, May 30, 1980; 46 FR 29689, June 2, 1981; 46 FR 35625, July 9, 1981. Redesignated at 48 FR 1182, Jan. 11, 1983, and amended at 48 FR 24874, June 3, 1983; 56 FR 23648, May 23, 1991; 61 FR 3804, Feb. 2, 1996; 61 FR 12027, Mar. 25, 1996]

§ 260.111 Criteria for selection of bidding systems and bidding system components.

(a) In analyzing the application of one of the bidding systems listed in § 260.110(a) to tracts selected for any OCS lease sale, MMS may, in its discretion, consider the following purposes and policies, recognizing that each of the purposes and policies may not be specifically applicable to the selection process for a particular bidding system and tract or may present a conflict that will have to be resolved in the process of bidding system selection, and that the order of listing does not denote a ranking:

(1) Providing fair return to the Federal Government;

(2) Increasing competition;

(3) Assuring competent and safe operations;

(4) Avoiding undue speculation;

(5) Avoiding unnecessary delays in exploration, development, and production;

(6) Discovering and recovering oil and gas;

(7) Developing new oil and gas resources in an efficient and timely manner;

(8) Limiting administrative burdens on Government and industry; and

(9) Providing an opportunity to experiment with various bidding systems to enable the identification of those that are the most appropriate for the satisfaction of the objectives of the United States in OCS lease sales.

(b) In performing the analysis referred to in paragraph (a), MMS may, in its discretion, take into account the following in relation to their impact upon the purposes and policies enumerated in paragraph (a) of this section.

(c) The bidding systems listed in § 260.110(a) (2) and (3) shall be applied to not less than 20 per centum and not more than 60 per centum of the total area offered for leasing each year during the five-year period commencing on September 18, 1978, unless DOI determines that the maximum and minimum per centum limitations set forth in this section are inconsistent with the purposes and policies of the OCSLA.

[45 FR 9539, Feb. 12, 1980. Redesignated and amended at 48 FR 1182, Jan. 11, 1983]

Subpart C [Reserved]

Subpart D—Joint Bidding

SOURCE: 45 FR 62031, Sept. 18, 1980, unless otherwise noted. Redesignated at 48 FR 1182, Jan. 11, 1983.

§ 260.301 Purpose.

The purpose of the regulations in this subpart D is to encourage participation in OCS oil and gas lease sales by limiting the requirement for filing Statements of Production to certain joint bidders.

§ 260.302 Definitions.

For purposes of this subpart D, all the terms used shall be defined as in 30 CFR 256.38.

§ 260.303 Joint bidding requirements.

(a) Any person who submits a joint bid for any OCS oil and gas lease during a six-month bidding period and who was chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products, shall have filed a Statement of Production with the Director, MMS, in accordance with the requirements of 30 CFR 256.38. The Statement of Production shall state that the person filing the Statement is chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products.

(b) No person chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products may submit a joint bid for any OCS oil and gas lease during the applicable six-

month bidding period with any other person similarly chargeable. Such bids shall be disqualified and rejected.

(c) No person may submit any bid during the applicable six-month bidding period pursuant to any agreement, the terms of which would result in two or more persons, each chargeable for the prior production period with an average daily production in excess of 1.6 million barrels of crude oil, natural gas equivalents, and liquefied petroleum products, acquiring or holding any interest in the tract for which the bid is submitted. Such bids shall be disqualified and rejected.

PART 270—NONDISCRIMINATION IN THE OUTER CONTINENTAL SHELF

Sec.

270.1 Purpose.
270.2 Application of this part.
270.3 Definitions.
270.4 Discrimination prohibited.
270.5 Complaint.
270.6 Process.
270.7 Remedies.

AUTHORITY: Sec. 604, Pub. L. 95–372, 92 Stat. 695 (43 U.S.C. 1863).

SOURCE: 50 FR 21048, May 22, 1985, unless otherwise noted.

§270.1 Purpose.

The purpose of this part is to implement the provisions of section 604 of the OCSLA of 1978 which provides that ''no person shall, on the grounds of race, creed, color, national origin, or sex, be excluded from receiving or participating in any activity, sale, or employment, conducted pursuant to the provisions of . . . the Outer Continental Shelf Lands Act.''

§270.2 Application of this part.

This part applies to any contract or subcontract entered into by a lessee or by a contractor or subcontractor of a lessee after the effective date of these regulations to provide goods, services, facilities, or property in an amount of $10,000 or more in connection with any activity related to the exploration for or development and production of oil, gas, or other minerals or materials in the OCS under the Act.

§270.3 Definitions.

As used in this part, the following terms shall have the meanings given below:

Contract means any business agreement or arrangement (in which the parties do not stand in the relationship of employer and employee) between a lessee and any person which creates an obligation to provide goods, services, facilities, or property.

Lessee means the party authorized by a lease, grant of right-of-way, or an approved assignment thereof to explore, develop, produce, or transport oil, gas, or other minerals or materials in the OCS pursuant to the Act and this part.

Person means a person or company, including but not limited to, a corporation, partnership, association, joint stock venture, trust, mutual fund, or any receiver, trustee in bankruptcy, or other official acting in a similar capacity for such company.

Subcontract means any business agreement or arrangement (in which the parties do not stand in the relationship of employer and employee) between a lessee's contractor and any person other than a lessee that is in any way related to the performance of any one or more contracts.

§270.4 Discrimination prohibited.

No contract or subcontract to which this part applies shall be denied to or withheld from any person on the grounds of race, creed, color, national origin, or sex.

§270.5 Complaint.

(a) Whenever any person believes that he or she has been denied a contract or subcontract to which this part applies on the grounds of race, creed, color, national origin, or sex, such person may complain of such denial or withholding to the Regional Director of the OCS Region in which such action is alleged to have occurred. Any complaint filed under this part must be submitted in writing to the appropriate Regional Director not later than 180 days after the date of the alleged unlawful denial of a contract or subcontract which is the basis of the complaint.

(b) The complaint referred to in paragraph (a) of this section shall be accompanied by such evidence as may be available to a person and which is relevant to the complaint including affidavits and other documents.

(c) Whenever any person files a complaint under this part, the Regional Director with whom such complaint is filed shall give written notice of such filing to all persons cited in the complaint no later than 10 days after receipt of such complaint. Such notice shall include a statement describing the alleged incident of discrimination, including the date and the names of persons involved in it.

§ 270.6 Process.

Whenever a Regional Director determines on the basis of any information, including that which may be obtained under § 270.5 of this title, that a violation of or failure to comply with any provision of this subpart probably occurred, the Regional director shall undertake to afford the complainant and the person(s) alleged to have violated the provisions of this part an opportunity to engage in informal consultations, meetings, or any other form of communications for the purpose of resolving the complaint. In the event such communications or consultations result in a mutually satisfactory resolution of the complaint, the complainant and all persons cited in the complaint shall notify the Regional Director in writing of their agreement to such resolution. If either the complainant or the person(s) alleged to have wrongfully discriminated fail to provide such written notice within a reasonable period of time, the Regional Director shall proceed in accordance with the provisions of §§ 250.70, 250.71, 250.72, and 250.80 of this title.

§ 270.7 Remedies.

In addition to the penalties available under §§ 250.81–1 and 250.80–2 of this title, the Director may invoke any other remedies available to him or her under the Act or regulations for the lessee's failure to comply with provisions of the Act, regulations, or lease.

PART 280—PROSPECTING FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR IN THE OUTER CONTINENTAL SHELF

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AUTHORITY: 43 U.S.C. 1331 *et seq.*, 42 U.S.C. 4332 *et seq.*

SOURCE: 53 FR 25256, July 5, 1988, unless otherwise noted.

§ 280.0 Authority for information collection.

The information collection requirements contained in part 280 have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* and assigned OMB clearance number 1010–0072. The information is being collected to inform the Minerals Management Service (MMS) of OCS minerals activities. The information will be used to ensure that such activities are conducted in a safe and environmentally responsible manner in compliance with governing laws and regulations. The obligation to respond is mandatory.

§ 280.1 Purpose and applicability.

Section 5(a) of the Act (43 U.S.C. 1334(a)(1)) states that the Secretary "* * * shall prescribe such rules and regulations * * * necessary to carry out * * *" the provisions of the Act. The primary purpose of the regulations

in this part is to prescribe policies, procedures, and requirements for conducting data and information-gathering activities associated with geological and geophysical (G&G) prospecting and scientific research in the OCS for minerals other than oil, gas, and sulphur. The regulations in this part do not apply to activities authorized under a mineral lease. Activities authorized under the regulations in this part do not give rise to any rights or interests in any OCS mineral discovered as a result of approved prospecting or scientific research activities.

§280.2 Definitions.

When used in this part, the following terms shall have the meaning given below:

Act means the OCS Lands Act, as amended (43 U.S.C. 1331 *et seq.)*

Adjacent State means with respect to any activity proposed, conducted, or approved under this part, any coastal State(s)—(1) That is used, or is scheduled to be used, as a support base for G&G prospecting or scientific research activities; or (2) in which there is a reasonable probability of significant effect on land or water uses from such activity.

Archaeological resource means any material remains of human life or activities that are at least 50 years of age and that are of archaeological interest.

Data means G&G facts and statistics or samples which have not been analyzed, processed, or interpreted.

Director means the Director of the MMS of the U.S. Department of the Interior or an official authorized to act on the Director's behalf.

Geological and geophysical (G&G) scientific research means any investigation conducted in the OCS for scientific research purposes which involves the gathering and analysis of G&G data and information which are made available to the public for inspection and reproduction at the earliest practicable time. This does not include scientific research related to oil, gas, and sulphur.

Geological sample means a collected portion of the seabed, the subseabed, or the overlying waters acquired while conducting prospecting or scientific research activities.

Governor means the Governor of a State or the person or entity lawfully designated to exercise the powers granted to a State Governor.

Information means G&G data that has been analyzed, processed, or interpreted.

Lease means one of the following, whichever is required by the context: Any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, specific minerals or the area covered by that authorization.

Material remains means physical evidence of human habitation, occupation, use, or activity, including the site, location, or context in which such evidence is situated.

Minerals has the same meaning as the term is defined in section 2(q) of the Act.

National Environmental Policy Act (NEPA) means the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*).

OCS minerals means any mineral found on or below the surface of the seabed but does not include oil, gas, or sulphur.

Of archaeological interest means capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics through the application of scientific or scholarly techniques, such as controlled observation, contextual measurements, controlled collection, analysis, interpretation, and explanation.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Permit means the contract or agreement, other than a lease, approved pursuant to this part under which a person acquires the right to conduct prospecting or scientific research activities.

Permittee means the person authorized by a permit issued pursuant to

this part to conduct prospecting or scientific research activities in the OCS.

Person means a citizen or national of the United States; an alien lawfully admitted for permanent residency in the United States as defined in 8 U.S.C. 1101(a)(20); a private, public, or municipal corporation organized under the laws of the United States or of any State or territory thereof; and an association of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States; or anyone operating in a manner provided for by treaty or other applicable international agreements. The term does not include Federal Agencies.

Prospecting activities means the gathering of any G&G data and information for the purpose of determining the feasibility of commercial recovery, which has as its objective the establishment and documentation of the nature, shape, concentration, location, and tenor of an OCS mineral resource. Such activities shall include (1) geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of minerals; and (2) the gathering through drilling or other means of geological samples which could be used for the purpose of discovering, characterizing, or evaluating OCS mineral deposits. Prospecting activities do not include G&G scientific research.

Secretary means the Secretary of the Interior or an official authorized to act on the Secretary's behalf.

Significant archaeological resource means those archaeological resources that meet the criteria of significance for eligibility to the National Register of Historic Places as defined in 36 CFR 60.4.

[53 FR 25256, July 5, 1988, as amended at 59 FR 53094, Oct. 21, 1994]

§ 280.3 Activities requiring a permit.

(a) No prospecting activities shall be conducted in the OCS without a permit approved by the Director pursuant to this part, unless such activities are being conducted pursuant to authority contained in a lease issued or maintained under part 256 or part 281 of this title or unless such activities are conducted by a Federal Agency.

(b) No person may conduct G&G scientific research activities in the OCS without a permit approved by the Director pursuant to this part if the proposed activities include either: (1) The drilling of a borehole to a depth greater than 300 feet below the seafloor; or (2) the use of solid or liquid explosives.

(c) Any person may conduct G&G scientific research in the OCS without obtaining a permit pursuant to this part if—

(1) The activities will not interfere with or endanger operations under any lease or right-of-way maintained or issued pursuant to the Act;

(2) The activities will not be unduly harmful to aquatic life in the area; result in pollution; create hazardous or unsafe conditions; unreasonably interfere with other uses of the area; or disturb any site, structure, or object of historical or archaeological significance; and

(3) The person conducting the activities or operating the vessel from which the activities are to be conducted has consulted and coordinated the conduct of those activities with any other users of the area.

(d) The Director may orally approve plan revisions or issue emergency permits to accommodate unforeseen or special circumstances. Oral approvals given for a written application shall be followed with a written confirmation by MMS. In the event an oral approval is given in response to an oral request, the applicant shall confirm the oral request in writing within 72 hours of the approval.

§ 280.4 Term of permit.

Permits approved under this part shall be granted for a term not to exceed 3 years. The Director may extend the term of a permit for an additional period(s) of time not to exceed a total of 2 years when the Director determines that the additional time is appropriate based upon a showing of good cause by the permittee.

§ 280.5 Application for a prospecting or scientific research permit.

(a) An application for a prospecting or scientific research permit shall be submitted to the Director at least 60 days prior to the date proposed as the

startup date for activities in the permit area.

(b)(1) An application for a prospecting permit shall be submitted in a form and manner approved by the Director. Three copies of each application shall be submitted and shall include—

(i) The name, address, and nationality of the person(s) submitting the application;

(ii) The name, address, and telephone number of the person(s) directly responsible for conducting the activities proposed;

(iii) A description and a map of the area(s) covered by the application;

(iv) The period of time to be covered by the primary term of the permit not to exceed 3 years;

(v) A narrative description in nonproprietary terms of the activities to be conducted, such as mapping, geophysical surveying, drilling, bottom sampling, and dredging;

(vi) A detailed description and schedule giving the estimated starting and completion dates for the proposed activities that are to be authorized under the permit; and

(vii) A prospecting plan.

(2) An applicant for a prospecting permit shall indicate which data and information included in the application and plan the applicant considers proprietary.

(c) Upon application submitted by a permittee pursuant to this section, the Director may approve the conversion of a permit issued under part 251 of this title to a permit issued under this part. A permit issued under part 251, which is converted to a permit issued under this part, shall be subject to all the requirements of this part.

(d) An application for a permit to conduct scientific research activities shall be submitted in a form approved by the Director. The application should be signed by an officer of the organization proposing to carry out the activity and shall state—

(1) The name of the person conducting the proposed research;

(2) The type of research activity and manner in which it will be conducted;

(3) The location designated on a map, plat, or chart where the research activity will be conducted;

(4) A schedule indicating the starting and completion dates for each proposed scientific research activity;

(5) The proposed time and manner in which the information and data resulting from the research will be made available to the public for inspection and reproduction, such time being the earliest practicable time;

(6) An agreement that the information and data resulting from the scientific research activity will not be sold or withheld for exclusive use;

(7) The name, registry number, registered owner, and port of registry of vessels used in the operation; and

(8) A scientific research plan.

(e) Within 30 days following the receipt of an application for a permit and the accompanying plan which does not require preparation of an environmental analysis the Director shall—

(1) Approve the application and plan;

(2) Require the applicant to modify the application and/or plan; or

(3) Disapprove the application and plan. If the Director disapproves an application and plan, the statement of rejection shall give the reasons for the disapproval and shall advise the applicant of the changes needed to obtain approval.

§280.6 Prospecting or scientific research plan.

(a) The applicant shall submit a plan with its application for a prospecting or scientific research permit. The plan shall include—

(1) Identification of the mineral(s) or material(s) of primary interest, if appropriate;

(2) A detailed description of the activities to be conducted;

(3) The type(s) of equipment to be used with special attention to safety and pollution prevention and control features and the name, registration, and mobile communication system of vessel(s);

(4) Maps showing location of proposed activities including drill holes, grab or basket samples, anticipated depth of penetration of drill holes, water depth, and location of proposed survey grids for each surveying method which is to be employed;

(5) A schedule indicating the starting and completion dates for each proposed activity;

(6) Anticipated environmental consequences of each proposed activity;

(7) Mitigation measures to be used to avoid or minimize adverse environmental impacts of proposed activities;

(8) For any activities which are to occur in an environmentally sensitive area, a plan for monitoring the effects of the activities on the environment;

(9) Any known archaeological resources in the area of the proposed activities; and

(10) Description of any potential conflicts with other uses or users in the permit area.

(b) If the penetration of one or more proposed drill holes will exceed 300 feet, the Director may require a drilling plan to be included as part of the plan before a permit is issued.

(c) If all needed information is not available at the time the plan is submitted, a plan shall indicate when the needed information will be obtained and submitted. In such a case, depending on the significance of the missing information, the Director may disapprove the plan, approve the plan based on the information submitted, or approve the plan with a specific condition that certain specified activities are not authorized and shall not be conducted until additional information is obtained and submitted for evaluation, and the Director gives specific approval to proceed with those activities.

§ 280.7 Obligations of persons.

(a) Activities authorized under a prospecting or scientific research permit issued under this part or research authorized pursuant to the provisions of § 280.5(c) of this part shall be conducted so as not to create conditions which will pose an unreasonable risk of—

(1) Interference with, or endangerment of, operations under any lease or permit issued or maintained pursuant to the Act;

(2) Serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life) or to the marine, coastal, or human environment;

(3) Serious, irreparable, or immediate harm or damage to property or to any mineral (in areas leased or not leased);

(4) Pollution;

(5) Disturbance of archaeological resources;

(6) Hazardous or unsafe conditions; or

(7) Interference with or serious, irreparable, or immediate harm to other uses of the area.

(b) The permittee or scientific researcher shall allow the Director to be present on any cruise.

(c) The permittee shall notify and obtain the prior approval of the Director before a substantial change from the approved plan is initiated.

§ 280.8 Reporting.

(a) The permittee shall submit a status report to the Director within 30 days of the close of each calendar quarter or more frequently if requested by the Director. The report shall include a summary of the prospecting or scientific research activities conducted prior to the end of the reporting period and the results obtained. The last quarterly report may be combined with the final report if the final report is submitted within 30 days after the end of the last quarter in which permitted activity occurs. Each permittee shall submit to the Director a final report of activities conducted under the permit within 6 months after expiration of the permit or after the completion of prospecting or scientific research activities, or 60 days prior to a planned lease offering when prospecting or scientific research activities are within the planned leasing area, whichever is sooner, provided that no report shall be required less than 30 days after completion of permitted activities. The report shall include—

(1) A description of the work performed;

(2) Charts, maps, or plats depicting the area and blocks in which any activities were conducted specifically, identifying the lines of geophysical traverses and/or the locations where geological activity was conducted;

(3) The dates on which the actual activities were performed;

(4) A narrative summary of any mineral occurrences encountered including location, environmental features, and

the nature and degree of adverse effects, if any, of the permitted activities on the environment, aquatic life, archaeological resources, or other uses of the area in which the activities were conducted;

(5) A report of the results of the environmental monitoring required in § 280.6(a)(8) of this part; and

(6) Such other descriptions of the activities conducted as may be specified by the Director.

(b) All persons shall immediately notify the Director of all serious accidents, any death or serious injury, or fire or explosion connected with any activity conducted pursuant to this part.

§ 280.9 Recordkeeping.

(a) Any permittee who acquires rock and mineral samples under a permit shall keep for 1 year after submittal of the final report a representative split of each geological sample and a quarter longitudinal segment of each core which shall be available for inspection at the convenience of the Director who may cut such core and geological samples for retention by MMS.

(b) Any permittee who acquires G&G data and information under a permit shall keep the data and information available for 3 years after submittal of the final report. The data and information shall be available for inspection and copying at a location within the appropriate OCS Region or at another location approved by the Director. The records shall include environmental data and information; G&G data and information; drill logs; analyses of cores, cuttings, and samples; and maps and navigation tapes showing the location where samples were taken and test drilling conducted.

§ 280.10 Environmental effects.

The potential of proposed prospecting or scientific research activities for adverse impact on the environment will be evaluated by MMS to determine the need for mitigation measures. The MMS anticipates that activities of the type listed below typically will not cause significant environmental impact and, in accordance with 516 DM 6, Appendix 10 to the Departmental Manual, will normally be categorically excluded from additional environmental analysis. The types of activities include—

(a) Gravity and magnetometric observations and measurements;

(b) Bottom and subbottom acoustic profiling or imaging without the use of explosives;

(c) Mineral sampling of a limited nature such as that using either test drillholes or cores to less than 300 feet below the seafloor;

(d) Water and biotic sampling, if the sampling does not adversely affect shellfish beds, marine mammals, or an endangered species or if permitted by the National Marine Fisheries Service or another Federal Agency;

(e) Meteorological observations and measurements, including the setting of instruments;

(f) Hydrographic and oceanographic observations and measurements, including the setting of instruments;

(g) Sampling by box core or grab sampler to determine seabed geological or geotechnical properties;

(h) Television and still photographic observation and measurements;

(i) Shipboard mineral assaying and analysis; and

(j) Placement of positioning systems, including bottom transponders and surface and subsurface buoys reported in Notices to Mariners.

§ 280.11 Notification.

(a) The Governor(s) of adjacent State(s) shall be notified by the Director with a copy of the application for a permit with the accompanying plan immediately upon the submission of an application for approval.

(b) In cases where an environmental assessment is to be prepared, the Director will invite the Governor(s) of adjacent States(s) to review and provide comments regarding the proposed activities. The Director's invitation to provide comments shall allow the Governor a specified period of time to comment.

(c) The Director shall notify Federal Agencies, as appropriate, with a copy of the application for a permit with the accompanying plan immediately upon the submission of the application for approval.

§ 280.12 Disclosure of information to the public.

(a) The Director shall make data, information, and samples available in accordance with the requirements and subject to the limitations of the Act, the Freedom of Information Act (5 U.S.C. 552), and the implementing regulations.

(b) For geological data, information, and samples and geophysical information submitted under a permit and retained by MMS, the Director shall make such data, information, and samples available to the public 25 years after the date of submission of the data and information or such earlier time as may be agreed to by the permittee who provides the data or information. Geophysical data submitted under a permit and retained by MMS shall be made available to the public by the Director 50 years after the date of submission to MMS unless an earlier date is agreed to by the permittee who submits the data.

(c) The Director reserves the right to disclose any data, information, or samples submitted by a permittee to an independent contractor or agent for the purpose of reproducing, processing, reprocessing, or interpreting the data or information. Such contractor or agent shall be subject to the same limitations on disclosure of data, information, and samples as those applicable to the Director under paragraph (b) of this section.

§ 280.13 Disclosure of data and information to the adjacent States.

(a) Proprietary data, information, and samples submitted to MMS by permittees shall be made available to adjacent State(s) upon request by the Governor(s) in accordance with paragraphs (b), (c), and (d) of this section.

(b) Disclosure shall occur only after the Governor has entered into an agreement with the Secretary providing that—

(1) The confidentiality of the information shall be maintained;

(2) In any action commenced against the Federal Government or the State for the failure to protect the confidentiality of proprietary information, the Federal Government or the State, as the case may be, may not raise as a defense any claim of sovereign immunity or any claim that the employee who revealed the proprietary information, which is the basis of the suit, was acting outside the scope of the person's employment in revealing the information;

(3) The State agrees to hold the United States harmless for any violation by the State or its employees or contractors of the agreement to protect the confidentiality of proprietary data and information and samples; and

(4) The materials containing the proprietary data, information, and samples shall remain the property of the United States.

(c) The data, information, and samples available to the State(s) pursuant to an agreement shall be related to leased lands.

(d) The materials containing the proprietary data, information, and samples shall be returned to MMS when they are no longer needed by the State or when requested by the Director.

§ 280.14 Suspension or temporary prohibition of activities.

The Director may suspend or temporarily prohibit the conduct of G&G prospecting or scientific research activities by notifying the person conducting the activity, either orally or in writing, when the Director determines that there is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral (in areas leased or not leased), the national security or defense, or the marine, coastal, or human environment; or there is a failure to comply with a provision of the Act or of any applicable law, the provisions of the permit, or provisions of these and other applicable regulations. Such suspension or temporary prohibition shall be effective immediately upon receipt of the notice. Suspensions or temporary prohibitions issued orally shall be followed by a written notice confirming the action, and all written notices will be sent by certified or registered mail. A suspension or temporary prohibition shall remain in effect until the basis for the suspension or temporary prohibition has been corrected to the satisfaction of the Director.

§280.15 Cancellation or relinquishment.

The Director may cancel or a permittee may relinquish, in whole or in part, a permit to conduct prospecting or scientific research activities at any time by sending a notice of cancellation or a notice of relinquishment. Such notices shall state the reason for the cancellation or relinquishment and shall be sent by certified or registered mail to the other party at least 30 days in advance of the date that the cancellation or relinquishment will be effective.

§280.16 Remedies and penalties.

Persons conducting activities in the OCS pursuant to this part shall be subject to the remedies and penalties provisions of section 24 of the Act and the applicable civil penalty procedures contained in part 250 of this title for noncompliance with any provision of the Act, permit, regulation, or order issued under the Act. The remedies or penalties prescribed in this section shall be in addition to any other penalty afforded by any other law or regulation.

§280.17 Appeals.

Orders or decisions issued under the regulations in this part may be appealed as provided in part 290 of this title.

PART 281—LEASING OF MINERALS OTHER THAN OIL, GAS, AND SULPHUR IN THE OUTER CONTINENTAL SHELF

Subpart A—General

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AUTHORITY: 43 U.S.C. 1331 *et seq.*

SOURCE: 54 FR 2049, Jan. 18, 1989, unless otherwise noted.

Subpart A—General

§281.0 Authority for information collection.

The information collection requirements contained in part 281 have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1010–0082. The information is being collected to determine if the applicant for a lease on the Outer Continental Shelf (OCS) is qualified to hold such a lease or to determine if a requested action is warranted. The information will be used to make those determinations. The obligation to respond is mandatory.

§ 281.1 Purpose and applicability.

The purpose of these regulations is to establish procedures under which the Secretary of the Interior (Secretary) will exercise the authority granted to administer a leasing program for minerals other than oil, gas, and sulphur in the OCS. The rules in this part apply exclusively to leasing activities for minerals other than oil, gas, and sulphur in the OCS pursuant to the Act.

§ 281.2 Authority.

The Act authorizes the Secretary to grant leases for any mineral other than oil, gas, and sulphur in any area of the OCS to the qualified persons offering the highest cash bonuses on the basis of competitive bidding upon such royalty, rental, and other terms and conditions as the Secretary may prescribe at the time of offering the area for lease (43 U.S.C. 1337(k)). The Secretary is to administer the leasing provisions of the Act and prescribe the rules and regulations necessary to carry out those provisions (43 U.S.C. 1334(a)).

§ 281.3 Definitions.

When used in this part, the following terms shall have the meaning given below:

Act means the OCS Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

Adjacent State means with respect to any activity proposed, conducted, or approved under this part, any coastal State—

(1) That is, or is proposed to be, receiving for processing, refining, or transshipping OCS mineral resources commercially recovered from the seabed;

(2) That is used, or is scheduled to be used, as a support base for prospecting, exploration, testing, and mining activities; or

(3) In which there is a reasonable probability of significant effect on land or water uses from such activity.

Director means the Director of the Minerals Management Service (MMS) of the U.S. Department of the Interior or an official authorized to act on the Director's behalf.

Governor means the Governor of a State or the person or entity designated by, or pursuant to, State law to exercise the powers granted to such Governor pursuant to the Act.

Lease means any form of authorization which is issued under section 8 of the Act and which authorizes exploration for, and development and production of, minerals, or the area covered by that authorization, whichever is required by the context.

Lessee means the person authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in this chapter. The term includes all persons holding that authority by or through the lessee.

OCS mineral means a mineral deposit or accretion found on or below the surface of the seabed but does not include oil, gas, sulphur; salt or sand and gravel intended for use in association with the development of oil, gas, or sulphur; or source materials essential to production of fissionable materials which are reserved to the United States pursuant to section 12(e) of the Act.

Outer Continental Shelf means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Overriding royalty means a royalty created out of the lessee's interest which is over and above the royalty reserved to the lessor in the original lease.

Person means a citizen or national of the United States; an alien lawfully admitted for permanent residency in the United States as defined in 8 U.S.C. 1101(a)(20); a private, public, or municipal corporation organized under the laws of the United States or of any State or territory thereof; an association of such citizens, nationals, resident aliens or private, public, or municipal corporations, States, or political subdivisions of States; or anyone operating in a manner provided for by treaty or other applicable international agreements. The term does not include Federal Agencies.

Secretary means the Secretary of the Interior or an official authorized to act on the Secretary's behalf.

§281.4 Qualifications of lessees.

(a) In accordance with section 8(k) of the Act, leases shall be awarded only to qualified persons offering the highest cash bonus bid.

(b) Mineral leases issued pursuant to section 8 of the Act may be held only by:

(1) Citizens and nationals of the United States;

(2) Aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20);

(3) Private, public, or municipal corporations organized under the laws of the United States or of any State or of the District of Columbia or territory thereof; or

(4) Associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

§281.5 False statements.

Under the provisions of 18 U.S.C. 1001, it is a crime punishable by up to 5 years imprisonment or a fine of $10,000, or both, for anyone knowingly and willfully to submit or cause to be submitted to any Agency of the United States any false or fraudulent statement(s) to any matters within the Agency's jurisdiction.

§281.6 Appeals.

Any party adversely affected by a decision of an MMS official made pursuant to the provisions of this part shall have the right of appeal pursuant to part 290 of this title, except as provided otherwise in §281.21 of this part.

§281.7 Disclosure of information to the public.

The Secretary shall make data and information available to the public in accordance with the requirements and subject to the limitations of the Act, the Freedom of Information Act (5 U.S.C. 552), and the implementing regulations (30 CFR parts 280 and 282 and 43 CFR part 2).

§281.8 Rights to minerals.

(a) Unless otherwise specified in the leasing notice, a lease for OCS minerals shall include rights to all minerals within the leased area except the following;

(1) Minerals subject to rights granted by existing leases;

(2) Oil;

(3) Gas;

(4) Sulphur;

(5) Minerals produced in direct association with oil, gas, or sulphur;

(6) Salt deposits which are identified in the leasing notice as being reserved;

(7) Sand and gravel deposits which are identified in the leasing notice as being reserved; and

(8) Source materials essential to production of fissionable materials which are reserved pursuant to section 12(a) of the Act.

(b) When an OCS mineral lease issued uner this part limits the minerals to which rights are granted, such lease shall include rights to minerals produced in direct association with the OCS mineral specified in the lease but not the rights to minerals specifically reserved.

(c) The existence of an OCS mineral, oil and gas, or sulphur lease shall not preclude the issuance of a lease(s) for other OCS minerals in the same area. However, no OCS mineral lease shall authorize or permit the lessee thereunder to unreasonably interfere with or endanger operations under an existing OCS mineral, oil and gas, or sulphur lease.

§281.9 Jurisdictional controversies.

In the event of a controversy between the United States and a State as to whether certain lands are subject to Federal or State jurisdiction (43 U.S.C. 1336), either the Governor or the Secretary may initiate negotiations in an attempt to settle the jurisdictional controversy. With the concurrence of the Attorney General, the Secretary may enter into an agreement with a State with respect to OCS mineral activities under the Act or under State authority and to payment and impounding of rents, royalties, and other sums and with respect to the offering of lands for lease pending settlement of the controversy.

Subpart B—Leasing Procedures

§ 281.11 Unsolicited request for a lease sale.

(a) Any person may at any time request that OCS minerals be offered for lease. A request that OCS minerals be offered for lease shall be submitted to the Director and shall contain the following information:

(1) The area to be offered for lease.

(2) The OCS minerals of primary interest.

(3) The available OCS mineral resource and environmental information pertaining to the area of interest to be offered for lease which supports the request.

(b) Within 45 days after receipt of a request submitted under paragraph (a) of this section, the Director shall either initiate steps leading to the offer of OCS minerals for lease and notify the applicant of the action taken or inform the applicant of the reasons for not initiating steps leading to the offer of OCS minerals for lease.

(c) Any interested party may at any time submit information to the Director concerning the scheduling of proposed lease sales of OCS minerals in any area of the OCS. Such information may include but not be limited to any of the following:

(1) Benefits of conducting a lease sale in an area.

(2) Costs of conducting a lease sale in an area.

(3) Geohazards which could be encountered in an area.

(4) Geological information about an area and mineral resource potential.

(5) Environmental information about an area.

(6) Information about known archaeological resources in an area.

§ 281.12 Request for OCS mineral information and interest.

(a) When considering whether to offer OCS minerals for lease, the Secretary, upon the Department of the Interior's own initiative or as a result of a submission under § 281.11, may request indications of interest in the leasing of a specific OCS mineral, a group of OCS minerals, or all OCS minerals in the area being considered for lease. Requests for information and interest shall be published in the FEDERAL REGISTER and may be published elsewhere.

(b) States and local governments, industry, other Federal Agencies, and all interested parties (including the public) may respond to a request for information and interest. All information provided to the Secretary will be considered in the decision whether to proceed with additional steps leading to the offering of OCS minerals for lease.

(c) The Secretary may request specific information concerning the offering of a specific OCS mineral, a group of OCS minerals, or all OCS minerals in a broad area for lease or the offering of one or more discrete tracts which represent a minable orebody. The Secretary's request may ask for comments on OCS areas which have been determined to warrant special consideration and analysis. Requests may be for comments concerning geological conditions or archaeological resources on the seabed; multiple uses of the area proposed for leasing, including navigation, recreation and fisheries; and other socioeconomic, biological, and environmental information relating to the area proposed for leasing.

[54 FR 2049, Jan. 18, 1989, as amended at 59 FR 53094, Oct. 21, 1994]

§ 281.13 Joint State/Federal coordination.

(a) The Secretary may invite the adjacent State Governor(s) to join in, or the adjacent State Governor(s) may request that the Secretary join in, the establishment of a State/Federal task force or some other joint planning or coordination arrangement when industry interest exists for OCS mineral leasing or geological information appears to support the leasing of OCS minerals in specific areas. Participation in joint State/Federal task forces or other arrangements will afford the adjacent State Governor(s) opportunity for access to available data and information about the area; knowledge of progress made in the leasing process and of the results of subsequent exploration and development activities; facilitate the resolution of issues of mutual interest; and provide a mechanism for planning, coordination, consultation, and other activities which the Secretary and the Governor(s) may

identify as contributing to the leasing process.

(b) State/Federal task forces or other such arrangement are to be constituted pursuant to such terms and conditions (consistent with Federal law and these regulations) as the Secretary and the adjacent State Governor(s) may agree.

(c) State/Federal task forces or other such arrangements will provide a forum which the Secretary and adjacent State Governor(s) may use for planning, consultation, and coordination on concerns associated with the offering of OCS minerals other than oil, gas, or sulphur for lease.

(d) With respect to the activities authorized under these regulations each State/Federal task force may make recommendations to the Secretary and adjacent State Governor(s) concerning:

(1) The identification of areas in which OCS minerals might be offered for lease;

(2) The potential for conflicts between the exploration and development of OCS mineral resources, other users and uses of the area, and means for resolution or mitigation of these conflicts;

(3) The economic feasibility of developing OCS mineral resources in the area proposed for leasing;

(4) Potential environmental problems and measures that might be taken to mitigate these problems;

(5) Development of guidelines and procedures for safe, environmentally responsible exploration and development practices; and

(6) Other issues of concern to the Secretary and adjacent State Governor(s).

(e) State/Federal task forces or other such arrangements might also be used to conduct or oversee research, studies, or reports (e.g., Environmental Impact Statements).

§281.14 OCS mining area identification.

The Secretary, after considering the available OCS mineral resources and environmental data and information, the recommendation of any joint State/Federal task force established pursuant to §281.13 of this part, and the comments received from interested parties, shall select the tracts to be considered for offering for lease. The selected tracts will be considered in the environmental analysis conducted for the proposed lease offering.

§281.15 Tract size.

The size of the tracts to be offered for lease shall be as determined by the Secretary and specified in the leasing notice. It is intended that tracts offered for lease be sufficiently large to include potentially minable OCS mineral orebodies. When the presence of any minable orebody is unknown and additional prospecting is needed to discover and delineate OCS minerals, the size of tracts specified in the leasing notice may be relatively large.

§281.16 Proposed leasing notice.

(a) Prior to offering OCS minerals in an area for lease, the Director shall assess the available information including recommendations of any joint State/Federal task force established pursuant to §281.13 of this part to determine lease sale procedures to be prescribed and to develop a proposed leasing notice which sets out the proposed primary term of the OCS mineral leases to be offered; lease stipulations including measures to mitigate potentially adverse impacts on the environment; and such rental, royalty, and other terms and conditions as the Secretary may prescribe in the leasing notice.

(b) The proposed leasing notice shall be sent to the Governor(s) of any adjacent State(s), and a Notice of its availability shall be published in the FEDERAL REGISTER at least 60 days prior to the publication of the leasing notice.

(c) Written comments of the adjacent State Governor(s) submitted within 60 days after publication of the Notice of Availability of the proposed leasing notice shall be considered by the Secretary.

(d) Prior to publication of the leasing notice, the Secretary shall respond in writing to the comments of the adjacent State Governor(s) stating the reasons for accepting or rejecting the Governor's recommendations, or for implementing any alternative mutually acceptable approach identified in consultation with the Governor(s) as a means to provide a reasonable balance between the national interest and the

well being of the citizens of the adjacent State.

§ 281.17 Leasing notice.

(a) The Director shall publish the leasing notice in the FEDERAL REGISTER at least 30 days prior to the date that OCS minerals will be offered for lease. The leasing notice shall state whether oral or sealed bids or a combination thereof will be used; the place, date, and time at which sealed bids shall be filed; and the place, date, and time at which sealed bids shall be opened and/or oral bids received. The leasing notice shall contain or reference a description of the tract(s) to be offered for lease; specify the mineral(s) to be offered for lease (if less than all OCS minerals are being offered); specify the period of time the primary term of the lease shall cover; and any stipulation(s), term(s), and condition(s) of the offer to lease (43 U.S.C. 1337(k)).

(b) The leasing notice shall contain a reference to the OCS minerals lease form which shall be issued to successful bidders.

(c) The leasing notice shall specify the terms and conditions governing the payment of the winning bid.

§ 281.18 Bidding system.

(a) The OCS minerals shall be offered by competitive, cash bonus bidding under terms and conditions specified in the leasing notice and in accordance with all applicable laws and regulations.

(b)(1) When the leasing notice specifies the use of sealed bids, such bids received in response to the leasing notice shall be opened at the place, date, and time specified in the leasing notice. The sole purpose of opening bids is to publicly announce and record the bids received, and no bids shall be accepted or rejected at that time.

(2) The Secretary reserves the right to reject any and all sealed bids received for any tract, regardless of the amount offered.

(3) In the event the highest bids are tie bids when using sealed bidding procedures, the tied bidders may be permitted to submit oral bids to determine the highest cash bonus bidder.

(c)(1) When the leasing notice specifies the use of oral bids, oral bids shall be received at the place, time, and date and in accordance with the procedures specified in the leasing notice.

(2) The Secretary reserves the right to reject all oral bids received for any tract, regardless of the amount offered.

(d) When the leasing notice specifies the use of deferred cash bonus bidding, bids shall be received in accordance with paragraph (b) or (c) of this section, as appropriate. The high bid will be determined based upon the net present value of each total bid. The appropriate discount rate will be specified in the leasing notice. High bidders using the deferred bonus option shall pay a minimum of 20 percent of the cash bonus bid prior to lease issuance. At least a total of 60 percent of the cash bonus bid shall be due on or before the 5th anniversary of the lease, and payment of the remainder of the cash bonus bid shall be due on the 10th anniversary of the lease. The lessee shall submit a bond guaranteeing payment of the deferred portion of the bonus, in accordance with § 281.33.

§ 281.19 Lease term.

An OCS mineral lease for OCS minerals other than sand and gravel shall be for a primary term of not less than 20 years as stipulated in the leasing notice. The primary lease term for each OCS mineral shall be determined based on exploration and development requirements for the OCS minerals being offered by the Secretary. An OCS mineral lease for sand and gravel shall be for a primary term of 10 years unless otherwise stipulated in the leasing notice. A lease will continue beyond the specified primary term for so long thereafter as leased OCS minerals are being produced in accordance with an approved mining operation or the lessee is otherwise in compliance with provisions of the lease and the regulations in this chapter under which a lessee can earn continuance of the OCS mineral lease in effect.

§ 281.20 Submission of bids.

(a) If the bidder is an individual, a statement of citizenship shall accompany the bid.

(b) If the bidder is an association (including a partnership), the bid shall be accompanied by a certified statement indicating the State in which it is registered and that the association is authorized to hold mineral leases on the OCS, or appropriate reference to statements or records previously submitted to an MMS OCS office (including material submitted in compliance with prior regulations).

(c) If the bidder is a corporation, the bid shall be accompanied by the following information:

(1) Either a statement certified by the corporate Secretary or Assistant Secretary over the corporate seal showing the State in which it was incorporated and that it is authorized to hold mineral leases on the OCS or appropriate reference to statements or record previously submitted to an MMS OCS office (including material submitted in compliance with prior regulations).

(2) Evidence of authority of persons signing to bind the corporation. Such evidence may be in the form of a certified copy of either the minutes of the board of directors or of the bylaws indicating that the person signing has authority to do so, or a certificate to that effect signed by the Secretary or Assistant Secretary of the corporation over the corporate seal, or appropriate reference to statements or records previously submitted to an MMS OCS office (including material submitted in compliance with prior regulations). Bidders are advised to keep their filings current.

(3) The bid shall be executed in conformance with corporate requirements.

(d) Bidders should be aware of the provisions of 18 U.S.C. 1860, which prohibits unlawful combination or intimidation of bidders.

(e) When sealed bidding is specified in the leasing notice, a separate sealed bid shall be submitted for each bid unit that is bid upon as described in the leasing notice. A bid may not be submitted for less than a bidding unit identified in the leasing notice.

(f) When oral bidding is specified in the leasing notice, information which must accompany a bid pursuant to paragraph (a), (b), or (c) of this section, shall be presented to MMS at the lease sale prior to the offering of an oral bid.

§ 281.21 Award of leases.

(a)(1) The decision of the Director on bids shall be the final action of the Department, subject only to reconsideration by the Secretary, pursuant to a written request in accordance with paragraph (a)(2) of this section. The delegation of review authority to the Office of Hearings and Appeals shall not be applicable to decisions on high bids for leases in the OCS.

(2) Any bidder whose bid is rejected by the Director may file a written request for reconsideration with the Secretary within 15 days of notice of rejection, accompanied by a statement of reasons with a copy to the Director. The Secretary shall respond in writing either affirming or reversing the decision.

(b) Written notice of the Director's action in accepting or rejecting bids shall be transmitted promptly to those bidders whose deposits have been held. If a bid is accepted, such notice shall transmit three copies of the lease form to the successful bidder. As provided in § 281.26 of this part, the bidder shall, not later than the 10th business day after receipt of the lease, execute the lease, pay the first year's rental, and unless payment of a portion of the bid is deferred, pay the balance of the bonus bid. When payment of a portion of the bid is deferred, the successful bidder shall also file a bond to guarantee payment of the deferred portion as required in § 281.33. Deposits shall be refunded on high bids subsequently rejected. When three copies of the lease have been executed by the successful bidder and returned to the Director, the lease shall be executed on behalf of the United States; and one fully executed copy shall be transmitted to the successful bidder.

(c) If the successful bidder fails to execute the lease within the prescribed time or to otherwise comply with the applicable regulations, the successful bidder's deposit shall be forfeited and disposed of in the same manner as other receipts under the Act.

(d) If, before the lease is executed on behalf of the United States, the land which would be subject to the lease is

withdrawn or restricted from leasing, the deposit shall be refunded.

(e) If the awarded lease is executed by an agent acting on behalf of the bidder, the bidder shall submit with the executed lease, evidence that the agent is authorized to act on behalf of the bidder.

§ 281.22 Lease form.

The OCS mineral leases shall be issued on the lease form prescribed by the Secretary in the leasing notice.

§ 281.23 Effective date of leases.

Leases issued under the regulations in this part shall be dated and become effective as of the first day of the month following the date leases are signed on behalf of the lessor except that, upon written request, a lease may be dated and become effective as of the first day of the month within which it is signed on behalf of the lessor.

Subpart C—Financial Considerations

§ 281.26 Payments.

(a) For sealed bids, a bonus bid deposit of a specified percentage of the total amount bid is required to be submitted with the bid. The percentage of bonus bid required to be deposited will be specified in the leasing notice. The remittance may be made in cash or by Federal Reserve check, commerical check, bank draft, money order, certified check, or cashier's check made payable to ''Department of the Interior—MMS.'' Payment of this portion of the bonus bid may not be made by Electronic Funds Transfer.

(b) For oral bids, a bonus bid deposit of a specified percentage of the total amount bid must be submitted to the official designated in the leasing notice following the completion of the oral bidding. The percentage of bonus bid required to be deposited will be specified in the leasing notice. Payment of this portion of the bonus bid shall be made by Electronic Fund Transfer within the timeframe specified in the leasing notice.

(c) The deposit received from high bidders will be placed in a Treasury account pending acceptance or rejection of the bid. Other bids submitted under paragraph (a) of this section will be returned to the bidders. If the high bid is subsequently rejected, an amount equal to that deposited with the high bid will be returned according to applicable regulations.

(d) The balance of the winning bonus bid and all rentals and royalties must be paid in accordance with the terms and conditions of this part, the Leasing Notice, and Subchapter A of this chapter.

(e) For each lease issued pursuant to this subpart, there shall be one person identified who shall be solely responsible for all payments due and payable under the provisions of the lease. The single responsible person shall be designated as the payor for the lease and shall be so identified on the Solid Minerals Payor Information Form (MMS–4030) in accordance with § 210.201 of this title. The designated person shall be responsible for all bonus, rental, and royalty payments.

(f) Royalty shall be computed at the rate specified in the leasing notice, and paid in value unless the Secretary elects to have the royalty delivered in kind.

(g) For leases which provide for minimum royalty payments, each lessee shall pay the minimum royalty specified in the lease at the end of each lease year beginning with the lease year in which production royalty is paid (whether the full amount specified in the lease or ½ the amount specified in the lease pursuant to § 281.28(b) on this part) of OCS minerals produced (sold, transferred, used, or otherwise disposed of) from the leasehold.

(h) Unless stated otherwise in the lease, product valuation will be in accordance with the regulations of this chapter. The value used in the computation of royalty shall be determined by the Director. The value, for royalty purposes, shall be the gross proceeds received by the lessee for produced substances at the point the product is produced and placed in its first marketable condition, consistent with prevailing practices in the industry. In establishing the value, the Director shall consider, in this order: (1) The price received by the lessee; (2) commodity and spot market transactions; (3) any other

valuation method proposed by the lessee and approved by the Director; and (4) value or cost netback. For non-arm's length transactions, the first benchmark will only be accepted if it is not less than the second benchmark.

(i) All payors must submit payments and payment information forms and maintain auditable records in accordance with the following Royalty Management regulations of this title:

Section 210.200—Required recordkeeping.
Section 210.201—Solid minerals payor information form.
Section 210.202—Report of sales and royalty remittance—solid minerals.
Section 210.203—Special forms and reports.
Section 212.200—Maintenance of and access to records.
Section 217.250—Audits.
Section 218.40—Assessments for incorrect or late reports and failure to report.
Section 218.50—Timing of payment.
Section 218.51—Method of payment.
Section 218.52—Designated payor.
Section 218.56—Definitions.
Section 218.150—Royalties, net profit shares, and rental payments.
Section 218.151—Rentals.
Section 218.155—Method of payment.
Section 218.202—Late payment or underpayment charges.
Section 241.20—Civil penalties authorized by statutes other than the Federal Oil and Gas Royalty Management Act of 1982.

§ 281.27 Annual rental.

(a) The annual lease rental shall be due and payable in accordance with the provisions of this section. No rental shall be due or payable under a lease commencing with the first lease anniversary date following the commencement of royalty payments on leasehold production computed on the basis of the royalty rate specified in the lease except that annual rental shall be due for any year in which production from the leasehold is not subject to royalty pursuant to § 281.28.

(b) Unless otherwise specified in the leasing notice and subsequently issued lease, no annual rental payment shall be due during the first 5 years in the life of a lease.

(c) The leasee shall pay an annual rental in the amount specified in the leasing notice and subsequently issued lease not later than the last day prior to the commencement of the rental year.

(d) A rental adjustment schedule and amount may be specified in a leasing notice and subsequently issued lease when a variance is warranted by geologic, geographic, technical, or economic conditions.

§ 281.28 Royalty.

(a) The royalty due the lessor on OCS minerals produced (i.e., sold, transferred, used, or otherwise disposed of) from a lease shall be set out in a separate schedule attached to and made a part of each lease and shall be as specified in the leasing notice. The royalty due on production shall be based on a percentage of the value or amount of the OCS mineral(s) produced, a sum assessed per unit of product, or other such method as the Secretary may prescribe in the leasing notice. When the royalty specified is a sum assessed per unit of product, the amount of the royalty shall be subject to an annual adjustment based on changes in the appropriate price index, when specified in the leasing notice. When the royalty is specified as a percentage of the value or amount of the OCS minerals produced, the Secretary will notify the lessee when and where royalty is to be delivered in kind.

(b) When prescribed in the leasing notice and subsequently issued lease, royalty due on OCS minerals produced from a leasehold will be reduced for up to any 5 consecutive years, as specified by the lessee prior to the commencement of production, during the 1st through 15th year in the life of the lease. No royalty shall be due in any year of the specified 5-year period that occurs during the 1st through 10th years in the life of the lease, and a royalty of one-half the amount specified in the lease shall be due in any year of the specified 5-year period that occurs in the 11th through 15th year in the life of the lease. The lessee shall pay the amount specified in the lease rental for any royalty free year. The minimum royalty specified in the lease shall apply during any year of reduced royalty.

§ 281.29 Royalty valuation.

The method of valuing the product from a leasehold shall be in accordance with regulations of this chapter and

procedures prescribed in the leasing notice and subsequently issued lease.

§ 281.30 Minimum royalty.

Unless otherwise specified in the leasing notice, each lease issued pursuant to the regulations in this part shall require the payment of a specified minimum annual royalty beginning with the year in which OCS minerals are produced (sold, transferred, used, or otherwise disposed of) from the leasehold except that the annual rentals shall apply during any year that royalty free production is in effect pursuant to § 281.28(b). Minimum royalty payments shall be offset by royalty paid on production during the lease year. Minimum royalty payments are due at the beginning of the lease year and payable by the end of the month following the end of the lease year for which they are due.

§ 281.31 Overriding royalties.

(a) Subject to the approval of the Secretary, an overriding royalty interest may be created by an assignment pursuant to section 8(e) of the Act. The Secretary may deny approval of an assignment which creates an overriding royalty on a lease whenever that denial is determined to be in the interest of conservation, necessary to prevent premature abandonment of a producing mine, or to make possible the mining of economically marginal or low-grade ore deposits. In any case, the total of applicable overriding royalties may not exceed 2.5 percent or one-half the base royalty due the Federal Government, whichever is less.

(b) No transfer or agreement may be made which creates an overriding royalty interest unless the owner of that interest files an agreement in writing that such interest is subject to the limitations provided in § 281.30 of this part, paragraph (a) of this section, and § 281.32 of this part.

§ 281.32 Waiver, suspension, or reduction of rental, minimum royalty or production royalty.

(a) The Secretary may waive, suspend, or reduce the rental, minimum royalty, and/or production royalty prescribed in a lease for a specified time period when the Secretary determines that it is in the national interest, it will result in the conservation of natural resources of the OCS, it will promote development, or the mine cannot be successfully operated under existing conditions.

(b) An application for waiver, suspension, or reduction of rental, minimum royalty, or production royalty under paragraph (a) of this section shall be filed in duplicate with the Director. The application shall contain the serial number(s) of the lease(s), the name of the lessee(s) of record, and the operator(s) if applicable. The application shall either:

(1)(i) Show the location and extent of all mining operations and a tabulated statement of the minerals mined and subject to royalty for each of the last 12 months immediately prior to filing the application:

(ii) Contain a detailed statement of expenses and costs of operating the lease, the income from the sale of any lease products, and the amount of all overriding royalties and payments out of production paid to others than the United States; and

(iii) All facts showing whether or not the mine(s) can be successfully operated under the royalty fixed in the lease; or

(2) If no production has occurred from the lease, show that the lease cannot be successfully operated under the rental, royalty, and other conditions specified in the lease.

(c) The applicant for a waiver, suspension, or reduction under this section shall file documentation that the lessee and the royalty holders agree to a reduction of all other royalties from the lease so that the aggregate of all other royalties does not exceed one-half the amount of the reduced royalties that would be paid to the United States.

§ 281.33 Bonds and bonding requirements.

(a) When the leasing notice specifies that payment of a portion of the bonus bid can be deferred, the lessee shall be required to submit a surety or personal bond to guarantee payment of a deferred portion of the bid. Upon the payment of the full amount of the cash

bonus bid, the lessee's bond will be released.

(b) All bonds to guarantee payment of the deferred portion of the high cash bonus bid furnished by the lessee must be in a form or on a form approved by the Associate Director for Offshore Minerals Management. A single copy of the required form is to be executed by the principal or, in the case of surety bonds, by both the principal and an acceptable surety.

(1) Only those surety bonds issued by qualified surety companies approved by the Department of the Treasury shall be accepted. (See Department of the Treasury Circular No. 570 and any supplemental or replacement circulars.)

(2) Personal bonds shall be accompanied by a cashier's check, certified check, or negotiable U.S. Treasury bonds of an equal value to the amount specified in the bond. Negotiable Treasury bonds shall be accompanied by a proper conveyance of full authority to the Director to sell such securities in case of default in the performance of the terms and conditions of the lease.

(c) Prior to the commencement of any activity on a lease(s), the lessee shall submit a surety or personal bond as described in § 282.40 of this title. Prior to the approval of a Delineation, Testing, or Mining Plan, the bond amount shall be adjusted, if appropriate, to cover the operations and activities described in the proposed plan.

[54 FR 2049, Jan. 18, 1989, as amended at 62 FR 27960, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27960, May 22, 1997, § 281.33 was amended by revising the first sentence of the introductory text of paragraph (b), effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 281.33 Bonds and bonding requirements.

* * * * *

(b) All bonds to guarantee payment of the deferred portion of the high cash bonus bid furnished by a lessee shall be in a form or on a form approved by the Director.* * *

* * * * *

Subpart D—Assignments and Lease Extensions

§ 281.40 Assignment of leases or interests therein.

(a) Subject to the approval of the Secretary, a lease may be assigned, in whole or in part, pursuant to section 8(e) of the Act to anyone qualified to hold a lease.

(b) Any approved assignment shall be deemed to be effective on the first day of the lease month following the date that it is submitted to the Director for approval unless by written request the parties request that the effective date be the first of the month in which the Director approves the assignment.

(c) The assignor shall be liable for all obligations under the lease occurring prior to the effective date of an assignment.

(d) The assignee shall be liable for all obligations under the lease occurring on or after the effective date of an assignment and shall comply with all terms and conditions of the lease and applicable regulations issued under the Act.

§ 281.41 Requirements for filing for transfers.

(a)(1) All instruments of transfer of a lease or of an interest therein including subleases and assignments of record interest shall be filed in triplicate for approval within 90 days from the date of final execution. They shall include a statement over the transferee's own signature with respect to citizenship and qualifications similar to that required of a lessee and shall contain all of the terms and conditions agreed upon by the parties thereto.

(2) An application for approval of any instrument required to be filed shall not be accepted unless accompanied by a nonrefundable fee of $50. Any document not required to be filed by these regulations but submitted for record purposes shall be accompanied by a nonrefundable fee of $50 per lease affected. Such documents may be rejected at the discretion of the authorized officer.

(b) An attorney in fact signing on behalf of the holder of a lease or sublease, shall furnish evidence of authority to execute the assignment or application

for approval and the statement required by § 281.20 of this part.

(c) Where an assignment creates separate leases, a bond shall be furnished for each of the resulting leases in the amount prescribed in § 282.40 of this title. Where an assignment does not create separate leases, the assignee, if the assignment so provides and the surety consents, may become a joint principal on the bond with the assignor.

(d) An heir or devisee of a deceased holder of a lease or any interest therein shall be recognized as the lawful successor to such lease or interest if evidence of status as an heir or devisee is furnished in the form of:

(1) A certified copy of an appropriate order or decree of the court having jurisdiction over the distribution of the estate, or

(2) If no court action is necessary, the statement of two disinterested persons having knowledge of the fact or a certified copy of the will.

(e) The heirs or devisee shall file statements that they are the persons named as successors to the estate with evidence of their qualifications to hold such lease or interest therein.

(f) In the event an heir or devisee is unable to qualify to hold the lease or interest, the heir or devisee shall be recognized as the lawful successor of the deceased and be entitled to hold the lease for a period not to exceed 2 years from the date of death of the predecessor in interest.

(g) Each obligation under any lease and under the regulations in this part shall inure to the heirs, executors, administrators, successors, or assignees of the lease.

§ 281.42 Effect of assignment on particular lease.

(a) When an assignment is made of all the record title to a portion of the acreage in a lease, the assigned and retained portions of the lease area become segregated into separate and distinct leases. In such a case, the assignee becomes a lessee of the Government as to the segregated tract that is the subject of the assignment and is bound by the terms of the lease as though the lease had been obtained from the United States in the assignee's own name, and the assignment, after its approval, shall be the basis of a new record. Royalty, minimum royalty, and annual rental provisions of the lease shall apply separately to each segregated portion.

(b) Each lease of an OCS mineral created by the segregation of a lease under paragraph (a) of this section shall continue in full force and effect for the remainder of the primary term of the original lease and so long thereafter as minerals are produced from the portion of the lease created by segregation in accordance with operations approved by the Director or the lessee is otherwise in compliance with provisions of the lease or regulations for earning the continuation of the lease in effect.

§ 281.43 Effect of suspensions on lease term.

(a) If the Director orders the suspension of either operations or production, or both, with respect to any lease in its primary term, the primary term of the lease shall be extended by a period of time equivalent to the period of the directed suspension.

(b) If the Director orders or approves the suspension of either operations or production, or both, with respect to any lease that is in force beyond its primary term, the term of the lease shall not be deemed to expire so long as the suspension remains in effect.

Subpart E—Termination of Leases

§ 281.46 Relinquishment of leases or parts of leases.

(a) A lease or any part thereof may be surrendered by the record title holder by filing a written relinquishment with the Director. A relinquishment shall take effect on the date it is filed subject to the continued obligation of the lessee and the surety to:

(1) Make all payments due, including any accrued rentals and royalties; and

(2) Abandon all operations, remove all facilities, and clear the land to be relinquished to the satisfaction of the Director.

(b) Upon relinquishment of a lease, the data and information submitted under the lease will no longer be held confidential and will be available to the public.

§ 281.47 Cancellation of leases.

(a) Whenever the owner of a nonproducing lease fails to comply with any of the provisions of the Act, the lease, or the regulations issued under the Act, and the default continues for a period of 30 days after mailing of notice by registered or certified letter to the lease owner at the owner's record post office address, the Secretary may cancel the lease pursuant to section 5(c) of the Act, and the lessee shall not be entitled to compensation. Any such cancellation is subject to judicial review as provided by section 23(b) of the Act.

(b) Whenever the owner of any producing lease fails to comply with any of the provisions of the Act, the lease, or the regulations issued under the Act, the Secretary may cancel the lease only after judicial proceedings pursuant to section 5(d) of the Act, and the lessee shall not be entitled to compensation.

(c) Any lease issued under the Act, whether producing or not, may be canceled by the Secretary upon proof that it was obtained by fraud or misrepresentation and after notice and opportunity to be heard has been afforded to the lessee.

(d) The Secretary may cancel a lease in accordance with the following:

(1) Cancellation may occur at any time if the Secretary determines after a hearing that:

(i) Continued activity pursuant to such lease would probably cause serious harm or damage to life (including fish and other aquatic life), to property, to any mineral (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment;

(ii) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(iii) The advantages of cancellation outweigh the advantages of continuing such lease in force;

(2) Cancellation shall not occur unless and until operations under such lease shall have been under suspension or temporary prohibition by the Secretary, with due extension of any lease term continuously for a period of 5 years, or for a lesser period upon request of the lessee; and

(3) Cancellation shall entitle the lessee to receive such compensation as is shown to the Secretary as being equal to the lesser of:

(i) The fair value of the canceled rights as of the date of cancellation, taking into account both anticipated revenues from the lease and anticipated costs, including costs of compliance with all applicable regulations and operating orders, liability for cleanup costs or damages, or both, and all other costs reasonably anticipated on the lease, or

(ii) The excess, if any, over the lessee's revenues from the lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for the lease and all direct expenditures made by the lessee after the date of issuance of such lease and in connection with exploration or development, or both, pursuant to the lease (plus interest on such consideration and such expenditures from date of payment to date of reimbursement), except that in the case of joint leases which are canceled due to the failure of one or more partners to exercise due diligence, the innocent parties shall have the right to seek damages for such loss from the responsible party or parties and the right to acquire the interests of the negligent party or parties and be issued the lease in question.

(iii) The lessee shall not be entitled to compensation where one of the following circumstances exists when a lease is canceled:

(A) A producing lease is forfeited or is canceled pursuant to section (5)(d) of the Act;

(B) A Testing Plan or Mining Plan is disapproved because of the lessee's failure to demonstrate compliance with the requirements of applicable Federal Law; or

(C) The lessee(s) of a nonproducing lease fails to comply with a provision of the Act, the lease, or regulations issued under the Act, and the noncompliance continues for a period of 30 days or more after the mailing of a notice of noncompliance by registered or certified letter to the lessee(s).

PART 282—OPERATIONS IN THE OUTER CONTINENTAL SHELF FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR

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AUTHORITY: 43 U.S.C. 1331 *et seq.*

SOURCE: 54 FR 2067, Jan. 18, 1989, unless otherwise noted.

Subpart A—General

§ 282.0 Authority for information collection.

The information collection requirements in this part have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1010–0081. The information is being collected to inform the Minerals Management Service (MMS) of general mining operations in the Outer Continental Shalf (OCS). The information will be used to ensure that operations are conducted in a safe and environmentally responsible manner in compliance with governing laws and regulations. The requirement to respond is mandatory.

§ 282.1 Purpose and authority.

(a) The Act authorizes the Secretary to prescribe such rules and regulations as may be necessary to carry out the provisions of the Act (43 U.S.C. 1334). The Secretary is authorized to prescribe and amend regulations that the Secretary determines to be necessary and proper in order to provide for the prevention of waste, conservation of the natural resources of the OCS, and the protection of correlative rights therein. In the enforcement of safety, environmental, and conservation laws and regulations, the Secretary is authorized to cooperate with adjacent States and other Departments and Agencies of the Federal Government.

(b) Subject to the supervisory authority of the Secretary, and unless otherwise specified, the regulations in this part shall be administered by the Director of the MMS.

§ 282.2 Scope.

The rules and regulations in this part apply as of their effective date to all operations conducted under a mineral lease for OCS minerals other than oil, gas, or sulphur issued under the provisions of section 8(k) of the Act.

§ 282.3 Definitions.

When used in this part, the following terms shall have the meaning given below:

Act means the OCS Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

Adjacent State means with respect to any activity proposed, conducted, or approved under this part, any coastal State—

(1) That is, or is proposed to be, receiving for processing, refining, or transshipment OCS mineral resources commercially recovered from the seabed;

(2) That is used, or is scheduled to be used, as a support base for prospecting, exploration, testing, or mining activities; or

(3) In which there is a reasonable probability of significant effect on land or water uses from such activity.

Contingency Plan means a plan for action to be taken in emergency situations.

Data means geological and geophysical (G&G) facts and statistics or samples which have not been analyzed, processed, or interpreted.

Development means those activities which take place following the discovery of minerals in paying quantities including geophysical activities, drilling, construction of offshore facilities, and operation of all onshore support facilities, which are for the purpose of ultimately producing the minerals discovered.

Director means the Director of MMS of the U.S. Department of the Interior or an official authorized to act on the Director's behalf.

Exploration means the process of searching for minerals on a lease including:

(1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of minerals;

(2) Any drilling including the drilling of a borehole in which the discovery of a mineral other than oil, gas, or sulphur is made and the drilling of any additional boreholes needed to delineate any mineral deposits; and

(3) The taking of sample portions of a mineral deposit to enable the lessee to determine whether to proceed with development and production.

Geological sample means a collected portion of the seabed, the subseabed, or the overylying waters (when obtained for geochemical analysis) acquired while conducting postlease mining activities.

Governor means the Governor of a State or the person or entity designated by, or pursuant to, State law to exercise the power granted to a Governor.

Information means G&G data that have been analyzed, processed, or interpreted.

Lease means one of the following, whichever is required by the context: Any form of authorization which is issued under section 8 or maintained under section 6 of the Acts and which authorizes exploration for, and development and production of, specific minerals; or the area covered by that authorization.

Lessee means the person authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in this chapter. The term includes all parties holding that authority by or through the lessee.

Major Federal action means any action or proposal by the Secretary which is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act (NEPA) (i.e., an action which will have a significant impact on the quality of the human environment requiring preparation of an Environmental Impact Statement (EIS) pursuant to section 102(2)(C) of NEPA).

Marine environment means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the OCS.

Minerals includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals which are authorized by an Act of Congress to be produced from ''public lands'' as defined in section 103 of the Federal Land Policy and Management Act of 1976.

OCS mineral means any mineral deposit or accretion found on or below the surface of the seabed but does not include oil, gas, or sulphur; salt or sand

and gravel intended for use in association with the development of oil, gas, or sulphur; or source materials essential to production of fissionable materials which are reserved to the United States pursuant to section 12(e) of the Act.

Operator means the individual, partnership, firm, or corporation having control or management of operations on the lease or a portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an approved operating agreement.

Outer Continental Shelf means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means a citizen or national of the United States; an alien lawfully admitted for permanent residency in the United States as defined in 8 U.S.C. 1101(a)(20); a private, public, or municipal corporation organized under the laws of the United States or of any State or territory thereof; an association of such citizens, nationals, resident aliens or private, public, or municipal corporations, States, or political subdivisions of States; or anyone operating in a manner provided for by treaty or other applicable international agreements. The term does not include Federal Agencies.

Secretary means the Secretary of the Interior or an official authorized to act on the Secretary's behalf.

Testing means removing bulk samples for processing tests and feasibility studies and/or the testing of mining equipment to obtain information needed to develop a detailed Mining Plan.

§ 282.4 Opportunities for review and comment.

(a) In carrying out MMS's responsibilities under the Act and regulations in this part, the Director shall provide opportunities for Governors of adjacent States, State/Federal task forces, lessees and operators, other Federal Agencies, and other interested parties to review proposed activities described in a Delineation, Testing, or Mining Plan together with an analysis of potential impacts on the environment and to provide comments and recommendations for the disposition of the proposed plan.

(b)(1) For Delineation Plans, the adjacent State Governor(s) shall be notified by the Director within 15 days following the submission of a request for approval of a Delineation Plan. Notification shall include a copy of the proposed Delineation Plan and the accompanying environmental information. The adjacent State Governor(s) who wishes to comment on a proposed Delineation Plan may do so within 30 days of the receipt of the proposed plan and the accompanying information.

(2) In cases where an Environmental Assessment is to be prepared, the Director's invitation to provide comments may allow the adjacent State Governor(s) more than 30 days following receipt of the proposed plan to provide comments.

(3) The Director shall notify Federal Agencies, as appropriate, with a copy of the proposed Delineation Plan and the accompanying environmental information within 15 days following the submission of the request. Agencies that wish to comment on a proposed Delineation Plan shall do so within 30 days following receipt of the plan and the accompanying information.

(c)(1) For Testing Plans, the adjacent State Governor(s) shall be notified by the Director within 20 days following submission of a request for approval of a proposed Testing Plan. Notification shall include a copy of the proposed Testing Plan and the accompanying environmental information. The adjacent State Governor(s) who wishes to comment on a proposed Testing Plan may do so within 60 days of the receipt of a plan and the accompanying information.

(2) In cases where an EIS is to be prepared, the Director's invitation to provide comments may allow the adjacent State Governor(s) more than 60 days following receipt of the proposed plan to provide comments.

(3) The Director shall notify Federal Agencies, as appropriate, with a copy of the proposed Testing Plan and the

accompanying environmental information within 20 days following the submission of the request. Agencies that wish to comment on a proposed Testing Plan shall do so within 60 days following receipt of the plan and the accompanying information.

(d)(1) For Mining Plans, the adjacent State Governor(s) shall be notified by the Director within 20 days following the submission of a request for approval of a proposed Mining Plan. Notification shall include a copy of the proposed Mining Plan and the accompanying environmental information. The adjacent State Governor(s) who wishes to comment on a proposed Mining Plan may do so within 60 days of the receipt of a plan and the accompanying information.

(2) In cases where an EIS is to be prepared, the Director's invitation to provide comments may allow the adjacent State Governor(s) more than 60 days following receipt of the proposed plan to provide comments.

(3) The Director shall notify Federal Agencies, as appropriate, with a copy of the proposed Mining Plan and the accompanying environmental information within 20 days following the submission of the request. Agencies that wish to comment on a proposed Mining Plan shall do so within 60 days following receipt of the plan and the accompanying information.

(e) When an adjacent State Governor(s) has provided comments pursuant to paragraphs (b), (c), and (d) of this section, the Governor(s) shall be given, in writing, a list of recommendations which are adopted and the reasons for rejecting any of the recommendations of the Governor(s) or for implementing any alternative means identified during consultations with the Governor(s).

§282.5 Disclosure of data and information to the public.

(a) The Director shall make data, information, and samples available in accordance with the requirements and subject to the limitations of the Act, the Freedom of Information Act (5 U.S.C. 552), and the implementing regulations (43 CFR part 2).

(b) Geophysical data, processed G&G information, interpreted G&G information, and other data and information submitted pursuant to the requirements of this part shall not be available for public inspection without the consent of the lessee so long as the lease remains in effect, unless the Director determines that earlier limited release of such information is necessary for the unitization of operations on two or more leases, to ensure proper Mining Plans for a common orebody, or to promote operational safety. When the Director determines that early limited release of data and information is necessary, the data and information shall be shown only to persons with a direct interest in the affected lease(s), unitization agreement, or joint Mining Plan.

(c) Geophysical data, processed geophysical information and interpreted geophysical information collected on a lease with high resolution systems (including, but not limited to, bathymetry, side-scan sonar, subbottom profiler, and magnetometer) in compliance with stipulations or orders concerning protection of environmental aspects of the lease may be made available to the public 60 days after submittal to the Director, unless the lessee can demonstrate to the satisfaction of the Director that release of the information or data would unduly damage the lessee's competitive position.

§282.6 Disclosure of data and information to an adjacent State.

(a) Proprietary data, information, and samples submitted to MMS pursuant to the requirements of this part shall be made available for inspection by representatives of adjacent State(s) upon request by the Governor(s) in accordance with paragraphs (b), (c), and (d) of this section.

(b) Disclosure shall occur only after the Governor has entered into an agreement with the Secretary providing that:

(1) The confidentiality of the information shall be maintained;

(2) In any action commenced against the Federal Government or the State for failure to protect the confidentiality of proprietary information, the Federal Government or the State, as the case may be, may not raise as a defense any claim of sovereign immunity

or any claim that the employee who revealed the proprietary information, which is the basis of the suit, was acting outside the scope of the person's employment in revealing the information;

(3) The State agrees to hold the United States harmless for any violation by the State or its employees or contractors of the agreement to protect the confidentiality of proprietary data, information, and samples; and

(c) The data, information, and samples available for inspection by representatives of adjacent State(s) pursuant to an agreement shall be related to leased lands.

§ 282.7 Jurisdictional controversies.

In the event of a controversy between the United States and a State as to whether certain lands are subject to Federal or State jurisdiction, either the Governor of the State or the Secretary may initiate negotiations in an attempt to settle the jurisdictional controversy. With the concurrence of the Attorney General, the Secretary may enter into an agreement with a State with respect to OCS mineral activities and to payment and impounding of rents, royalties, and other sums and with respect to the issuance or nonissuance of new leases pending settlement of the controversy.

Subpart B—Jurisdiction and Responsibilities of Director

§ 282.10 Jurisdiction and responsibilities of Director.

Subject to the authority of the Secretary, the following activities are subject to the regulations in this part and are under the jurisdiction of the Director: Exploration, testing, and mining operations together with the associated environmental protection measures needed to permit those activities to be conducted in an environmentally responsible manner; handling, measurement, and transportation of OCS minerals; and other operations and activities conducted pursuant to a lease issued under part 281 of this chapter, or pursuant to a right of use and easement granted under this part, by or on behalf of a lessee or the holder of a right of use and easement.

§ 282.11 Director's authority.

(a) In the exercise of jurisdiction under § 282.10, the Director is authorized and directed to act upon the requests, applications, and notices submitted under the regulations in this part; to issue either written or oral orders to govern lease operations; and to require compliance with applicable laws, regulations, and lease terms so that all operations conform to sound conservation practices and are conducted in a manner which is consistent with the following:

(1) Make such OCS minerals available to meet the nation's needs in a timely manner;

(2) Balance OCS mineral resource development with protection of the human, marine, and coastal environments;

(3) Ensure the public a fair and equitable return on OCS minerals leased on the OCS; and

(4) Foster and encourage private enterprise.

(b)(1) The Director is to be provided ready access to all OCS mineral resource data and all environmental data acquired by the lessee or holder of a right of use and easement in the course of operations on a lease or right of use and easement and may require a lessee or holder to obtain additional environmental data when deemed necessary to assure adequate protection of the human, marine, and coastal environments.

(2) The Director is to be provided an opportunity to inspect, cut, and remove representative portions of all samples acquired by a lessee in the course of operations on the lease.

(c) In addition to the rights and privileges granted to a lessee under any lease issued or maintained under the Act, on request, the Director may grant a lessee, subject to such conditions as the Director may prescribe, a right of use and easement to construct and maintain platforms, artificial islands, and/or other installations and devices which are permanently or temporarily attached to the seabed and which are needed for the conduct of leasehold exploration, testing, development, production, and processing activities or other leasehold related operations whether on or off the lease.

(d)(1) The Director may approve the consolidation of two or more OCS mineral leases or portions of two or more OCS mineral leases into a single mining unit requested by lessees, or the Director may require such consolidation when the operation of those leases or portions of leases as a single mining unit is in the interest of conservation of the natural resources of the OCS or the prevention of waste. A mining unit may also include all or portions of one or more OCS mineral leases with all or portions of one or more adjacent State leases for minerals in a common orebody. A single unit operator shall be responsible for submission of required Delineation, Testing, and Mining Plans covering OCS mineral operations for an approved mining unit.

(2) Operations such as exploration, testing, and mining activities conducted in accordance with an approved plan on any lease or portion of a lease which is subject to an approved mining unit shall be considered operations on each of the leases that is made subject to the approved mining unit.

(3) Minimum royalty paid pursuant to a Federal lease, which is subject to an approved mining unit, is creditable against the production royalties allocated to that Federal lease during the lease year for which the minimum royalty is paid.

(4) Any OCS minerals produced from State and Federal leases which are subject to an approved mining unit shall be accounted for separately unless a method of allocating production between State and Federal leases has been approved by the Director and the appropriate State official.

§ 282.12 Director's responsibilities.

(a) The Director is responsible for the regulation of activities to assure that all operations conducted under a lease or right of use and easement are conducted in a manner that protects the environment and promotes orderly development of OCS mineral resources. Those activities are to be designed to prevent serious harm or damage to, or waste of, any natural resource (including OCS mineral deposits and oil, gas, and sulphur resources in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

(b)(1) In the evaluation of a Delineation Plan, the Director shall consider whether the plan is consistent with:

(i) The provisions of the lease;

(ii) The provisions of the Act;

(iii) The provisions of the regulations prescribed under the Act;

(iv) Other applicable Federal law; and

(v) Requirements for the protection of the environment, health, and safety.

(2) Within 30 days following the completion of an environmental assessment or other NEPA document prepared pursuant to the regulations implementing NEPA or within 30 days following the comment period provided in § 282.4(b) of this part, the Director shall:

(i) Approve any Delineation Plan which is consistent with the criteria in paragraph (b)(1) of this section;

(ii) Require the lessee to modify any Delineation Plan that is inconsistent with the criteria in paragraph (b)(1) of this section; or

(iii) Disapprove a Delineation Plan when it is determined that an activity proposed in the plan would probably cause serious harm or damage to life (including fish and other aquatic life); to property; to natural resources of the OCS including mineral deposits (in areas leased or not leased); or to the marine, coastal, or human environment, and the proposed activity cannot be modified to avoid the conditions.

(3) The Director shall notify the lessee in writing of the reasons for disapproving a Delineation Plan or for requiring modification of a plan and the conditions that must be met for plan approval.

(c)(1) In the evaluation of a Testing Plan, the Director shall consider whether the plan is consistent with:

(i) The provisions of the lease;

(ii) The provisions of the Act;

(iii) The provisions of the regulations prescribed under the Act;

(iv) Other applicable Federal law;

(v) Environmental, safety, and health requirements; and

(vi) The statutory requirement to protect property, natural resources of the OCS, including mineral deposits (in areas leased or not leased), and the national security or defense.

(2) Within 60 days following the release of a final EIS prepared pursuant to NEPA or within 60 days following the comment period provided in § 282.4(c) of this part, the Director shall:

(i) Approve any Testing Plan which is consistent with the criteria in paragraph (c)(1) of this section;

(ii) Require the lessee to modify any Testing Plan which is inconsistent with the criteria in paragraph (c)(1) of this section; or

(iii) Disapprove any Testing Plan when the Director determines the existence of exceptional geological conditions in the lease area, exceptional resource values in the marine or coastal environment, or other exceptional circumstances and that (A) implementation of the activities described in the plan would probably cause serious harm and damage to life (including fish and other aquatic life), to property, to any mineral deposit (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environments; (B) that the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and (C) the advantages of disapproving the Testing Plan outweigh the advantages of development and production of the OCS mineral resources.

(3) The Director shall notify the lessee in writing of the reason(s) for disapproving a Testing Plan or for requiring modification of a Testing Plan and the conditions that must be met for approval of the plan.

(d)(1) In the evaluation of a Mining Plan, the Director shall consider whether the plan is consistent with:

(i) The provisions of the lease;

(ii) The provisions of the Act;

(iii) The provisions of the regulations prescribed under the Act;

(iv) Other applicable Federal law;

(v) Environmental, safety, and health requirements; and

(vi) The statutory requirements to protect property, natural resources of the OCS, including mineral deposits (in areas leased or not leased), and the national security or defense.

(2) Within 60 days following the release of a final EIS prepared pursuant to NEPA or within 60 days following the comment period provided in § 282.4(d) of this part, the Director shall:

(i) Approve any Mining Plan which is consistent with the criteria in paragraph (d)(1) of this section;

(ii) Require the lessee to modify any Mining Plan which is inconsistent with the criteria in paragraph (d)(1) of this section; or

(iii) Disapprove any Mining Plan when the Director determines the existence of exceptional geological conditions in the lease area, exceptional resource values in the marine or coastal environment, or other exceptional circumstances, and that—

(A) Implementation of the activities described in the plan would probably cause serious harm and damage to life (including fish and other aquatic life), to property, to any mineral deposit (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environments;

(B) That the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(C) The advantages of disapproving the Mining Plan outweigh the advantages of development and production of the OCS mineral resources.

(3) The Director shall notify the lessee in writing of the reason(s) for disapproving a Mining Plan or for requiring modification of a Mining Plan and the conditions that must be met for approval of the plan.

(e) The Director shall assure that a scheduled onsite compliance inspection of each facility which is subject to regulations in this part is conducted at least once a year. The inspection shall be to determine that the lessee is in compliance with the requirements of the law; provisions of the lease; the approved Delineation, Testing, or Mining Plan; and the regulations in this part. Additional unscheduled onsite inspections shall be conducted without advance notice to the lessee to assure compliance with the provisions of applicable law; the lease; the approved Delineation, Testing, or Mining Plan; and the regulations in this part.

(f)(1) The Director shall, after completion of the technical and environmental evaluations, approve, disapprove, or require modification of the lessee's requests, applications, plans, and notices submitted pursuant to the provisions of this part; issue orders to govern lease operations; and require compliance with applicable provisions of the law, the regulations, the lease, and the approved Delineation, Testing, or Mining Plans. The Director may give oral orders or approvals whenever prior approval is required before the commencement of an operation or activity. Oral orders or approvals given in response to a written request shall be confirmed in writing within 3 working days after issuance of the order or granting of the oral approval.

(2) The Director shall, after completion of the technical and environmental evaluations, approve, disapprove, or require modification, as appropriate, of the design plan, fabrication plan, and installation plan for platforms, artificial islands, and other installations and devices permanently or temporarily attached to the seabed. The approval, disapproval, or requirement to modify such plans may take the form of a condition of granting a right of use and easement under paragraph (a) of this section or as authorized under any lease issued or maintained under the Act.

(g) The Director shall establish practices and procedures to govern the collection of all rents, royalties, and other payments due the Federal Government in accordance with terms of the leasing notice, the lease, and the applicable Royalty Management regulations listed in §281.26(i) of this chapter.

(h) The Director may prescribe or approve, in writing or orally, departures from the operating requirements of the regulations of this part when such departures are necessary to facilitate the proper development of a lease; to conserve natural resources; or to protect life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

§282.13 Suspension of production or other operations.

(a) The Director may direct the suspension or temporary prohibition of production or any other operation or activity on all or any part of a lease when it has been determined that such suspension or temporary prohibition is in the national interest to:

(1) Facilitate proper development of a lease including a reasonable time to develop a mine and construct necessary support facilities, or

(2) Allow for the construction or negotiation for use of transportation facilities.

(b) The Director may also direct or, at the request of the lessee, approve a suspension or temporary prohibition of production or any other operation or activity, if:

(1) The lessee failed to comply with a provision of applicable law, regulation, order, or the lease;

(2) There is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment;

(3) The suspension or temporary prohibition is in the interest of national security or defense;

(4) The suspension or temporary prohibition is necessary for the initiation and conduct of an environmental evaluation to define mitigation measures to avoid or minimize adverse environmental impacts.

(5) The suspension or temporary prohibition is necessary to facilitate the installation of equipment necessary for safety of operations and protection of the environment;

(6) The suspension or temporary prohibition is necessary to allow for undue delays encountered by the lessee in obtaining required permits or consents, including administrative or judicial challenges or appeals;

(7) The Director determines that continued operations would result in premature abandonment of a producing mine, resulting in the loss of otherwise recoverable OCS minerals;

(8) The Director determines that the lessee cannot successfully operate a producing mine due to market conditions that are either temporary in nature or require temporary shutdown and reinvestment in order for the lessee to adapt to the conditions; or

(9) The suspension or temporary prohibition is necessary to comply with judicial decrees prohibiting production or any other operation or activity, or the permitting of those activities, effective the date set by the court for that prohibition.

(c) When the Director orders or approves a suspension or a temporary prohibition of operation or activity including production on all of a lease pursuant to paragraph (a) or (b) of this section, the term of the lease shall be extended for a period of time equal to the period of time that the suspension or temporary prohibition is in effect, except that no lease shall be so extended when the suspension or temporary prohibition is the result of the lessee's gross negligence or willful violation of a provision of the lease or governing regulations.

(d) The Director may, at any time within the period prescribed for a suspension or temporary prohibition issued pursuant to paragraph (b)(2) of this section, require the lessee to submit a Delineation, Testing, or Mining Plan for approval in accordance with the requirements for the approval of such plans in this part.

(e)(1) When the Director orders or issues a suspension or a temporary prohibition pursuant to paragraph (b)(2) of this section, the Director may require the lessee to conduct site-specific studies to identify and evaluate the cause(s) of the hazard(s) generating the suspension or temporary prohibition, the potential for damage from the hazard(s), and the measures available for mitigating the hazard(s). The nature, scope, and content of any study shall be subject to approval by the Director. The lessee shall furnish copies and all results of any such study to the Director. The cost of the study shall be borne by the lessee unless the Director arranges for the cost of the study to be borne by a party other than the lessee. The Director shall make results of any such study available to interested parties and to the public as soon as practicable after the completion of the study and submission of the results thereof.

(2) When the Director determines that measures are necessary, on the basis of the results of the studies conducted in accordance with paragraph (e)(1) of this section and other information available to and identified by the Director, the lessee shall be required to take appropriate measures to mitigate, avoid, or minimize the damage or potential damage on which the suspension or temporary prohibition is based. When deemed appropriate by the Director, the lessee shall submit a revised Delineation, Testing, or Mining Plan to incorporate the mitigation measures required by the Director. In choosing between alternative mitigation measures, the Director shall balance the cost of the required measures against the reduction or potential reduction in damage or threat of damage or harm to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment.

(f)(1) If under the provisions of paragraphs (b) (2), (3), and (4) of this section, the Director, with respect to any lease, directs the suspension of production or other operations on the entire leasehold, no payment of rental or minimum royalty shall be due for or during the period of the directed suspension and the time for the lessee specify royalty free period of a period of reduced royalty pursuant to § 281.28(b) of this subchapter will be extended for the period of directed suspension. If under the provisions of paragraphs (b) (2), (3), and (4) of this section the Director, with respect to a lease on which there has been no production, directs the suspension of operations on the entire leasehold, no payment of rental shall be due during the period of the directed suspension.

(2) If under the provisions of this section, the Director grants the request of a lessee for a suspension of production or other operations, the lessee's obligations to pay rental, minimum royalty, or royalty shall continue to apply during the period of the approved suspension, unless the Director's approval of the lessee's request for suspension authorizes the payment of a lesser amount during the period of approved suspension. If under the provision of

this section, the Director grants a lessee's request for a suspension of production or other operations for a lease which includes provisions for a time period which the lessee may specify during which production from the leasehold would be royalty free or subject to a reduced royalty obligation pursuant to § 281.28(b) of this subchapter, the time during which production from a leasehold may be royalty free or subject to a reduced royalty obligation shall not be extended unless the Director's approval of the suspension specifies otherwise.

(3) If the lease anniversary date falls within a period of suspension for which no rental or minimum royalty payments are required under paragraph (a) of this section, the prorated rentals or minimum royalties are due and payable as of the date the suspension period terminates. These amounts shall be computed and notice thereof given the lessee. The lessee shall pay the amount due within 30 days after receipt of such notice. The anniversary date of a lease shall not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.

§ 282.14 Noncompliance, remedies, and penalties.

(a)(1) If the Director determines that a lessee has failed to comply with applicable provisions of law; the regulations in this part; other applicable regulations; the lease; the approved Delineation, Testing, or Mining Plan; or the Director's orders or instructions, and the Director determines that such noncompliance poses a threat of immediate, serious, or irreparable damage to the environment, the mine or the deposit being mined, or other valuable mineral deposits or other resources, the Director shall order the lessee to take immediate and appropriate remedial action to alleviate the threat. Any oral orders shall be followed up by service of a notice of noncompliance upon the lessee by delivery in person to the lessee or agent, or by certified or registered mail addressed to the lessee at the last known address.

(2) If the Director determines that the lessee has failed to comply with applicable provisions of law; the regulations in this part; other applicable regulations; the lease; the requirements of an approved Delineation, Testing, or Mining Plan; or the Director's orders or instructions, and such noncompliance does not pose a threat of immediate, serious, or irreparable damage to the environment, the mine or the deposit being mined, or other valuable mineral deposits or other resources, the Director shall serve a notice of noncompliance upon the lessee by delivery in person to the lessee or agent or by certified or registered mail addressed to the lessee at the last known address.

(b) A notice of noncompliance shall specify in what respect(s) the lessee has failed to comply with the provisions of applicable law; regulations; the lease; the requirements of an approved Delineation, Testing, or Mining Plan; or the Director's orders or instructions, and shall specify the action(s) which must be taken to correct the noncompliance and the time limits within which such action must be taken.

(c) Failure of a lessee to take the actions specified in the notice of noncompliance within the time limit specified shall be grounds for a suspension of operations and other appropriate actions, including but not limited to the assessment of a civil penalty of up to $10,000 per day for each violation that is not corrected within the time period specified (43 U.S.C. 1350(b)).

(d) Whenever the Director determines that a violation of or failure to comply with any provision of the Act; or any provision of a lease, license, or permit issued pursuant to the Act; or any provision of any regulation promulgated under the Act probably occurred and that such apparent violation continued beyond notice of the violation and the expiration of the reasonable time period allowed for corrective action, the Director shall follow the procedures concerning remedies and penalties in subpart N, Remedies and Penalties, of part 250 of this title to determine and assess an appropriate penalty.

(e) The remedies and penalties prescribed in this section shall be concurrent and cumulative, and the exercise of one shall not preclude the exercise of the other. Further, the remedies and

penalties prescribed in this section shall be in addition to any other remedies and penalties afforded by any other law or regulation (43 U.S.C. 1350(e)).

§ 282.15 Cancellation of leases.

(a) Whenever the owner of a nonproducing lease fails to comply with any of the provisions of the Act, the lease, or the regulations issued under the Act, and the default continues for a period of 30 days after mailing of notice by registered or certified letter to the lease owner at the owner's record post office address, the Secretary may cancel the lease pursuant to section 5(c) of the Act, and the lessee shall not be entitled to compensation. Any such cancellation is subject to judicial review as provided by section 23(b) of the Act.

(b) Whenever the owner of any producing lease fails to comply with any of the provisions of the Act, the lease, or the regulations issued under the Act, the Secretary may cancel the lease only after judicial proceedings pursuant to section 5(d) of the Act, and the lessee shall not be entitled to compensation.

(c) Any lease issued under the Act, whether producing or not, may be canceled by the Secretary upon proof that it was obtained by fraud or misrepresentation and after notice and opportunity to be heard has been afforded to the lessee.

(d) The Secretary may cancel a lease in accordance with the following:

(1) Cancellation may occur at any time if the Secretary determines after a hearing that—

(i) Continued activity pursuant to such lease would probably cause serious harm or damage to life (including fish and other aquatic life), to property, to any mineral (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment;

(ii) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(iii) The advantages of cancellation outweigh the advantages of continuing such lease in force.

(2) Cancellation shall not occur unless and until operations under such lease shall have been under suspension or temporary prohibition by the Secretary, with due extension of any lease term continuously for a period of 5 years or for a lesser period upon request of the lessee;

(3) Cancellation shall entitle the lessee to receive such compensation as is shown to the Secretary as being equal to the lesser of—

(i) The fair value of the canceled rights as of the date of cancellation, taking account of both anticipated revenues from the lease and anticipated costs, including costs of compliance with all applicable regulations and operating orders, liability for cleanup costs or damages, or both, and all other costs reasonably anticipated on the lease, or

(ii) The excess, if any, over the lessee's revenue from the lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for the lease and all direct expenditures made by the lessee after the date of issuance of such lease and in connection with exploration or development, or both, pursuant to the lease (plus interest on such consideration and such expenditures from date of payment to date of reimbursement), except that in the case of joint leases which are canceled due to the failure of one or more partners to exercise due diligence, the innocent parties shall have the right to seek damages for such loss from the responsible party or parties and the right to acquire the interests of the negligent party or parties and be issued the lease in question.

(iii) The lessee shall not be entitled to compensation where one of the following circumstances exists when a lease is canceled:

(A) A producing lease is forfeited or is canceled pursuant to section (5)(d) of the Act;

(B) A Testing Plan or Mining Plan is disapproved because the lessee's failure to demonstrate compliance with the requirements of applicable Federal law; or

(C) The lessee of a nonproducing lease fails to comply with a provision of the Act, the lease, or regulations issued under the Act, and the noncompliance continues for a period of 30 days or more after the mailing of a notice of

noncompliance by registered or certified letter to the lessee.

Subpart C—Obligations and Responsibilities of Lessees

§ 282.20 Obligations and responsibilities of lessees.

(a) The lessee shall comply with the provisions of applicable laws; regulations; the lease; the requirements of the approved Delineation, Testing, or Mining Plans; and other written or oral orders or instructions issued by the Director when performing exploration, testing, development, and production activities pursuant to a lease issued under part 281 of this title. The lessee shall take all necessary precautions to prevent waste and damage to oil, gas, sulphur, and other OCS mineral-bearing formations and shall conduct operations in such manner that does not cause or threaten to cause harm or damage to life (including fish and other aquatic life); to property; to the national security or defense; or to the marine, coastal, or human environment (including onshore air quality). The lessee shall make all mineral resource data and information and all environmental data and information acquired by the lessee in the course of exploration, testing, development, and production operations on the lease available to the Director for examination and copying at the lease site or an onshore location convenient to the Director.

(b) In all cases where there is more than one lease owner of record, one person shall be designated payor for the lease. The payor shall be responsible for making all rental, minimum royalty, and royalty payments.

(c) In all cases where lease operations are not conducted by the sole lessee, a ''designation of operator'' shall be submitted to and accepted by the Director prior to the commencement of leasehold operations. This designation when accepted will be recognized as authority for the designee to act on behalf of the lessees and to fulfill the lessees' obligations under the Act, the lease, and the regulations of this part. All changes of address and any termination of a designation of operator shall be reported immediately, in writing, to the Director. In the case of a termination of a designation of operator or in the event of a controversy between the lessee and the designated operator, both the lessee and the designated operator will be responsible for the protection of the interests of the lessor.

(d) When required by the Director or at the option of the lessee, the lessee shall submit to the Director the designation of a local representative empowered to receive notices, provide access to OCS mineral and environmental data and information, and comply with orders issued pursuant to the regulations of this part. If there is a change in the designated representative, the Director shall be notified immediately.

(e) Before beginning operations, the lessee shall inform the Director in writing of any designation of a local representative under paragraph (d) of this section and the address of the mine office responsible for the exploration, testing, development, or production activities; the lessee's temporary and permanent addresses; or the name and address of the designated operator who will be responsible for the operations, and who will act as the local representative of the lessee. The Director shall also be informed of each change thereafter in the address of the mine office or in the name or address of the local representative.

(f) The holder of a right of use and easement shall exercise its rights under the right of use and easement in accordance with the regulations of this part.

(g) A lessee shall submit reports and maintain records in accordance with § 282.29 of this part.

(h) When an oral approval is given by MMS in response to an oral request under these regulations, the oral request shall be confirmed in writing by the lessee or holder of a right of use and easement within 72 hours.

(i) The lessee is responsible for obtaining all permits and approvals from MMS or other Agencies needed to carry out exploration, testing, development, and production activities under a lease issued under part 281 of this title.

§ 282.21 Plans, general.

(a) No exploration, testing, development, or production activities, except preliminary activities, shall be commenced or conducted on any lease except in accordance with a plan submitted by the lessee and approved by the Director. Plans will not be approved before completion of comprehensive technical and environmental evaluations to assure that the activities described will be carried out in a safe and environmentally responsible manner. Prior to the approval of a plan, the Director will assure that the lessee is prepared to take adequate measures to prevent waste; conserve natural resources of the OCS; and protect the environment, human life, and correlative rights. The lessee shall demonstrate to the satisfaction of the Director that the lease is in good standing, the lessee is authorized and capable of conducting the activities described in the plan, and that an acceptable bond has been provided.

(b) Plans shall be submitted to the Director for approval. The lessee shall submit the number of copies prescribed by the Director. Such plans shall describe in detail the activities that are to be conducted and shall demonstrate that the proposed exploration, testing, development, and production activities will be conducted in an operationally safe and environmentally responsible manner that is consistent with the provisions of the lease, applicable laws, and regulations. The Governor of an affected State and other Federal Agencies shall be provided an opportunity to review and provide comments on proposed Delineation, Testing, and Mining Plans and any proposal for a significant modification to an approved plan. Following review, including the technical and environmental evaluations, the Director shall either approve, disapprove, or require the lessee to modify its proposed plan.

(c) Lessees are not required to submit a Delineation or Testing Plan prior to submittal of a proposed Testing or Mining Plan if the lessee has sufficient data and information on which to base a Testing or Mining Plan without carrying out postlease exploration and/or testing activities. A Mining Plan may include proposed exploration or testing activities where those activities are needed to obtain additional data and information on which to base plans for future mining activities. A Testing Plan may include exploration activities when those activities are needed to obtain additional data or information on which to base plans for future testing or mining activities.

(d) Preliminary activities are bathymetric, geological, geophysical, mapping, and other surveys necessary to develop a comprehensive Delineation, Testing, or Mining Plan. Such activities are those which have no significant adverse impact on the natural resources of the OCS. The lessee shall give notice to the Director at least 30 days prior to initiating the proposed preliminary activities on the lease. The notice shall describe in detail those activities that are to be conducted and the time schedule for conducting those activities.

(e) Leasehold activities shall be carried out with due regard to conservation of resources, paying particular attention to the wise management of OCS mineral resources, minimizing waste of the leased resource(s) in mining and processing, and preventing damage to unmined parts of the mineral deposit and other resources of the OCS.

§ 282.22 Delineation Plan.

All exploration activities shall be conducted in accordance with a Delineation Plan submitted by the lessee and approved by the Director. The Delineation Plan shall describe the proposed activities necessary to locate leased OCS minerals, characterize the quantity and quality of the minerals, and generate other information needed for the development of a comprehensive Testing or Mining Plan. A Delineation Plan at a minimum shall include the following:

(a) The OCS mineral(s) or primary interest.

(b) A brief narrative description of the activities to be conducted and how the activities will lead to the discovery and evaluation of a commercially minable deposit on the lease.

(c) The name, registration, and type of equipment to be used, including vessel types as well as their navigation

and mobile communication systems, and transportation corridors to be used between the lease and shore.

(d) Information showing that the equipment to be used (including the vessel) is capable of performing the intended operation in the environment which will be encountered.

(e) Maps showing the proposed locations of test drill holes, the anticipated depth of penetration of test drill holes, the locations where surficial sample were taken, and the location of proposed geophysical survey lines for each surveying method being employed.

(f) A description of measures to be taken to avoid, minimize, or otherwise mitigate air, land, and water pollution and damage to aquatic and wildlife species and their habitats; any unique or special features in the lease area; aquifers; other natural resources of the OCS; and hazards to public health, safety, and navigation.

(g) A schedule indicating the starting and completion dates for each proposed exploration activity.

(h) A list of any known archaeological resources on the lease and measures to assure that the proposed exploration activities do not damage those resources.

(i) A description of any potential conflicts with other uses and users of the area.

(j) A description of measures to be taken to monitor the effects of the proposed exploration activities on the environment in accordance with § 282.28(c) of this part.

(k) A detailed description of practices and procedures to effect the abandonment of exploration activities, e.g., plugging of test drill holes. The proposed procedures shall indicate the steps to be taken to assure that test drill holes and other testing procedures which penetrate the seafloor to a significant depth are properly sealed and that the seafloor is left free of obstructions or structures that may present a hazard to other uses or users of the OCS such as navigation or commercial fishing.

(l) A detailed description of the cycle of all materials, the method for discharge and disposal of waste and refuse, and the chemical and physical characteristics of waste and refuse.

(m) A description of the potential environmental impacts of the proposed exploration activities including the following:

(1) The location of associated port, transport, processing, and waste disposal facilities and affected environment (e.g., maps, land use, and layout);

(2) A description of the nature and degree of environmental impacts and the domestic socioeconomic effects of construction and operation of the associated facilities, including waste characteristics and toxicity;

(3) Any proposed mitigation measures to avoid or minimize adverse impacts on the environment;

(4) A certificate of consistency with the federally approved State coastal zone management program, where applicable; and

(5) Alternative sites and technologies considered by the lessee and the reasons why they were not chosen.

(n) Any other information needed for technical evaluation of the planned activity, such as sample analyses to be conducted at sea, and the evaluation of potential environmental impacts.

§ 282.23 Testing Plan.

All testing activities shall be conducted in accordance with a Testing Plan submitted by the lessee and approved by the Director. Where a lessee needs more information to develop a detailed Mining Plan than is obtainable under an approved Delineation Plan, to prepare feasibility studies, to carry out a pilot program to evaluate processing techniques or technology or mining equipment, or to determine environmental effects by a pilot test mining operation, the lessee shall submit a comprehensive Testing Plan for the Director's approval. Any OCS minerals acquired during activities conducted under an approved Testing Plan will be subject to the payment of royalty pursuant to the governing lease terms. A Testing Plan at a minimum shall include the following:

(a) The nature and purpose of the proposed testing program.

(b) A comprehensive description of the activities to be performed including descriptions of the proposed methods for analysis of samples taken.

(c) A narrative description and maps showing water depths and the locations of the proposed pilot mining or other testing activities.

(d) A comprehensive description of the method and manner in which testing activities will be conducted and the results the lessee expects to obtain as a result of those activities.

(e) The name, registration, and type of equipment to be used, including vessel types together with their navigation and mobile communication systems, and transportation corridors to be used between the lease and shore.

(f) Information showing that the equipment to be used (including the vessel) is capable of performing the intended operation in the environment which will be encountered.

(g) A schedule specifying the starting and completion dates for each of the testing activities.

(h) A list of known archaeological resources on the lease and measures to be used to assure that the proposed testing activities do not damage those resources.

(i) A description of any potential conflicts with other uses and users of the area.

(j) A description of measures to be taken to avoid, minimize, or otherwise mitigate air, land, and water pollution and damage to aquatic and wildlife species and their habitat; any unique or special features in the lease area, other natural resources of the OCS; and hazards to public health, safety, and navigation.

(k) A description of the measures to be taken to monitor the impacts of the proposed testing activities in accordance with § 282.28(c) of this part.

(l) A detailed description of the cycle of all materials including samples and wastes, the method for discharge and disposal of waste and refuse, and the chemical and physical characteristics of such waste and refuse.

(m) A detailed description of practices and procedures to effect the abandonment of testing activities, e.g., abandonment of a pilot mining facility. The proposed procedures shall indicate the steps to be taken to assure that mined areas do not pose a threat to the environment and that the seafloor is left free of obstructions and structures that may present a hazard to other uses or users of the OCS such as navigation or commercial fishing.

(n) A description of potential environmental impacts of testing activities including the following:

(1) The location of associated port, transport, processing, and waste disposal facilities and affected environment (e.g., maps, land use, and layout);

(2) A description of the nature and degree of potential environmental impacts of the proposed testing activities and the domestic socioeconomic effects of construction and operation of the proposed testing facilities, including waste characteristics and toxicity;

(3) Any proposed mitigation measures to avoid or minimize adverse impacts on the environment;

(4) A certificate of consistency with the federally approved State coastal zone management program, where applicable; and

(5) Alternate sites and technologies considered by the lessee and the reasons why they were not selected.

(o) Any other information needed for technical evaluation of the planned activities and for evaluation of the impact of those activities on the human, marine, and coastal environments.

§ 282.24 Mining Plan.

All OCS mineral development and production activities shall be conducted in accordance with a Mining Plan submitted by the lessee and approved by the Director. A Mining Plan shall include comprehensive detailed descriptions, illustrations, and explanations of the proposed OCS mineral development, production, and processing activities and accurately present the lessee's proposed plan of operation. A Mining Plan at a minimum shall include the following:

(a) A narrative description of the mining activities including:

(1) The OCS mineral(s) or material(s) to be recovered;

(2) Estimates of the number of tons and grade(s) of ore to be recovered;

(3) Anticipated annual production;

(4) Volume of ocean bottom expected to be disturbed (area and depth of disruption) each year; and

(5) All activities of the mining cycle from extraction through processing and waste disposal.

(b) Maps of the lease showing water depths, the outline of the mineral deposit(s) to be mined with cross sections showing thickness, and the area(s) anticipated to be mined each year.

(c) The name, registration, and type of equipment to be used, including vessel types as well as their navigation and mobile communication systems, and transportation corridors to be used between the lease and shore.

(d) Information showing that the equipment to be used (including the vessel) is capable of performing the intended operation in the environment which will be encountered.

(e) A description of equipment to be used in mining, processing, and transporting of the ore.

(f) A schedule indicating the anticipated starting and completion dates for each activity described in the plan.

(g) For onshore processing, a description of how OCS minerals are to be processed and how the produced OCS minerals will be weighed, assayed, and royalty determinations made.

(h) For at-sea processing, additional information including type and size of installation or structures and the method of tailings disposal.

(i) A list of known archaeological resources on the lease and the measures to be taken to assure that the proposed mining activities do not damage those resources.

(j) Description of any potential conflicts with other uses and users of the area.

(k) A detailed description of the nature and occurrence of the OCS mineral deposit(s) in the leased area with adequate maps and sections.

(l) A detailed description of development and mining methods to be used, the proposed sequence of mining or development, the expected production rate, the method and location of the proposed processing operation, and the method of measuring production.

(m) A detailed description of the method of transporting the produced OCS minerals from the lease to shore and adequate maps showing the locations of pipelines, conveyors, and other transportation facilities and corridors.

(n) A detailed description of the cycle of all materials including samples and wastes, the method of discharge and disposal of waste and refuse, and the chemical and physical characteristics of the waste and refuse.

(o) A description of measures to be taken to avoid, minimize, or otherwise mitigate air, land, and water pollution and damage to aquatic and wildlife species and their habitats; any unique or special features in the lease area, aquifers, or other natural resources of the OCS; and hazards to public health, safety, and navigation.

(p) A detailed description of measures to be taken to monitor the impacts of the proposed mining and processing activities on the environment in accordance with § 282.28(c) of this part.

(q) A detailed description of practices and procedures to effect the abandonment of mining and processing activities. The proposed procedures shall indicate the steps to be taken to assure that mined areas on tailing deposits do not pose a threat to the environment and that the seafloor is left free of obstructions and structures that present a hazard to other users or uses of the OCS such as navigation or commercial fishing.

(r) A description of potential environmental impacts of mining activities including the following:

(1) The location of associated port, transport, processing, and waste disposal facilities and the affected environment (e.g., maps, land use, and layout);

(2) A description of the nature and degree of potential environmental impacts of the proposed mining activities and the domestic socioeconomic effects of construction and operation of the associated facilities, including waste characteristics and toxicity;

(3) Any proposed mitigation measures to avoid or minimize adverse impacts on the environment;

(4) A certificate of consistency with the federally approved State coastal zone management program, where applicable; and

(5) Alternative sites and technologies considered by the lessee and the reasons why they were not chosen.

(s) Any other information needed for technical evaluation of the proposed

activities and for the evaluation of potential impacts on the environment.

§ 282.25 Plan modification.

Approved Delineation, Testing, and Mining Plans may be modified upon the Director's approval of the changes proposed. When circumstances warrant, the Director may direct the lessee to modify an approved plan to adjust to changed conditions. If the lessee requests the change, the lessee shall submit a detailed, written statement of the proposed modifications, potential, impacts, and the justification for the proposed changes. Revision of an approved plan whether initiated by the lessee or ordered by the Director shall be submitted to the Director for approval. When the Director determines that a proposed revision could result in significant change in the impacts previously identified and evaluated or requires additional permits, the proposed plan revision shall be subject to the applicable review and approval procedures of §§ 282.21, 282.22, 282.23, and 282.24 of this part.

§ 282.26 Contingency Plan.

(a) When required by the Director, a lessee shall include a Contingency Plan as part of its request for approval of a Delineation, Testing, or Mining Plan. The Contingency Plan shall comply with the requirements of § 282.28(e) of this part.

(b) The Director may order or the lessee may request the Director's approval of a modification of the Contingency Plan when such a change is necessary to reflect any new information concerning the nature, magnitude, and significance of potential equipment or procedural failures or the effectiveness of the corrective actions described in the Contingency Plan.

§ 282.27 Conduct of operations.

(a) The lessee shall conduct all exploration, testing, development, and production activities and other operations in a safe and workmanlike manner and shall maintain equipment in a manner which assures the protection of the lease and its improvements, the health and safety of all persons, and the conservation of property, and the environment.

(b) Nothing in this part shall preclude the use of new or alternative technologies, techniques, procedures, equipment, or activities, other than those prescribed in the regulations of this part, if such other technologies, techniques, procedures, equipment, or activities afford a degree of protection, safety, and performance equal to or better than that intended to be achieved by the regulations of this part, provided the lessee obtains the written approval of the Director prior to the use of such new or alternative technologies, techniques, procedures, equipment, or activities.

(c) The lessee shall immediately notify the Director when there is a death or serious injury; fire, explosion, or other hazardous event which threatens damage to life, a mineral deposit, or equipment; spills of oil, chemical reagents, or other liquid pollutants which could cause pollution; or damage to aquatic life or the environment associated with operations on the lease. As soon as practical, the lessee shall file a detailed report on the event and action(s) taken to control the situation and to mitigate any further damage.

(d)(1) Lessees shall provide means, at all reasonable hours either day or night, for the Director to inspect or investigate the conditions of the operation and to determine whether applicable regulations; terms and conditions of the lease; and the requirements of the approved Delineation, Testing, or Mining Plan are being met.

(2) A lessee shall, on request by the Director, furnish food, quarters, and transportation for MMS representatives to inspect its facilities. Upon request, the lessee will be reimbursed by the United States for the actual costs which it incurs as a result of its providing food, quarters, and transportation for an MMS representative's stay of more than 10 hours. Request for reimbursement must be submitted within 60 days following the cost being incurred.

(e) Mining and processing vessels, platforms, structures, artificial islands, and mobile drilling units which have helicopter landing facilities shall be identified with at least one sign using letters and figures not less than

12 inches in height. Signs for structures without helicopter landing facilities shall be identified with at least one sign using letters and figures not less than 3 inches in height. Signs shall be affixed at a location that is visible to approaching traffic and shall contain the following information which may be abbreviated:

(1) Name of the lease operator;

(2) The area designation based on Official OCS Protraction Diagrams;

(3) The block number in which the facility is located; and

(4) Vessel, platform, structure, or rig name.

(f)(1) Drilling.

(i) When drilling on lands valuable or potentially valuable for oil and gas or geopressured or geothermal resources, drilling equipment shall be equipped with blowout prevention and control devices acceptable to the Director before penetrating more than 500 feet unless a different depth is specified in advance by the Director.

(ii) In cases where the Director determines that there is sufficient liklihood of encountering pressurized hydrocarbons, the Director may require that the lessee comply with all or portions of the requirements in part 250, subpart D, of this title.

(iii) Before drilling any hole which may penetrate an aquifer, the lessee shall follow the procedures included in the approved plan for the penetration and isolation of the aquifer during the drilling operation, during use of the hole, and for subsequent abandonment of the hole.

(iv) Cuttings from holes drilled on the lease shall be disposed of and monitored in accordance with the approved plan.

(v) The use of muds in drilling holes on the lease and their subsequent disposition shall be according to the approved plan.

(2) All drill holes which are susceptible to logging shall be logged, and the lessee shall prepare a detailed lithologic log of each drill hole. Drill holes which are drilled deeper than 500 feet shall be drilled in a manner which permits logging. Copies of logs of cores and cuttings and all in-hole surveys such as electronic logs, gamma ray logs, neutron density logs, and sonic logs shall be provided to the Director.

(3) Drill holes for exploration, testing, development, or production shall be properly plugged and abandoned to the satisfaction of the Director in accordance with the approved plan and in such a manner as to protect the surface and not endanger any operation; any freshwater aquifer; or deposit of oil, gas, or other mineral substance.

(g) The use of explosives on the lease shall be in accordance with the approved plan.

(h)(1) Any equipment placed on the seabed shall be designed to allow its recovery and removal upon abandonment of leasehold activities.

(2) Disposal of equipment, cables, chains, containers, or other materials into the ocean is prohibited.

(3) Materials, equipment, tools, containers, and other items used on the OCS which are of such shape or configuration that they are likely to snag or damage fishing devices shall be handled and marked as follows:

(i) All loose materials, small tools, and other small objects shall be kept in a suitable storage area or a marked container when not in use or in a marked container before transport over OCS waters;

(ii) All cable, chain, or wire segments shall be recovered after use and securely stored;

(iii) Skid-mounted equipment, portable containers, spools or reels, and drums shall be marked with the owner's name prior to use or transport over OCS waters; and

(iv) All markings must clearly identify the owner and must be durable enough to resist the effects of the environmental conditions to which they are exposed.

(4) Any equipment or material described in paragraphs (h)(2), (h)(3)(ii), and (h)(3)(iii) of this section that is lost overboard shall be recorded on the daily operations report of the facility and reported to the Director and to the U.S. Coast Guard.

(i) Any bulk sampling or testing that is necessary to be conducted prior to submission of a Mining Plan shall be in accordance with an approved Testing Plan. The sale of any OCS minerals acquired under an approved Testing Plan

shall be subject to the payment of the royalty specified in the lease to the United States.

(j) Installations and structures.

(1) The lessee shall design, fabricate, install, use, inspect, and maintain all installations and structures, including platforms on the OCS, to assure the structural integrity of all installations and structures for the safe conduct of exploration, testing, mining, and processing activities considering the specific environmental conditions at the location of the installation or structure.

(2) All fixed or bottom-founded platforms or other structures, e.g., artificial islands shall be designed, fabricated, installed, inspected, and maintained in accordance with the provisions of part 250, subpart I, of this title.

(k) The lessee shall not produce any OCS mineral until the method of measurement and the procedures for product valuation have been instituted in accordance with the approved Testing or Mining Plan. The lessee shall enter the weight or quantity and quality of each mineral produced in accordance with § 282.29 of this title.

(l) The lessee shall conduct OCS mineral processing operations in accordance with the approved Testing or Mining Plan and use due diligence in the reduction, concentration, or separation of mineral substances by mechanical or chemical processes, by evaporation, or other means, so that the percentage of concentrates or other mineral substances are recovered in accordance with the practices approved in the Testing or Mining Plan.

(m) No material shall be discharged or disposed of except in accordance with the approved disposal practice and procedures contained in the approved Delineation, Testing, or Mining Plan.

§ 282.28 Environmental protection measures.

(a) Exploration, testing, development, production, and processing activities proposed to be conducted under a lease will only be approved by the Director upon the determination that the adverse impacts of the proposed activities can be avoided, minimized, or otherwise mitigated. The Director shall take into account the information contained in the sale-specific environmental evaluation prepared in association with the lease offering as well as the site- and operational-specific environmental evaluations prepared in association with the review and evaluation of the approved Delineation, Testing, or Mining Plan. The Director's review of the air quality consequences of proposed OCS activities will follow the practices and procedures specified in §§ 250.26, 250.33(b)(19), 250.34(b)(12), and 250.45 of this title.

(b) If the baseline data available are judged by the Director to be inadequate to support an environmental evaluation of a proposed Delineation, Testing, or Mining Plan, the Director may require the lessee to collect additional environmental baseline data prior to the approval of the activities proposed.

(c)(1) The lessee shall monitor activities in a manner that develops the data and information necessary to enable the Director to assess the impacts of exploration, testing, mining, and processing activities on the environment on and off the lease; develop and evaluate methods for mitigating adverse environmental effects; validate assessments made in previous environmental evaluations; and ensure compliance with lease and other requirements for the protection of the environment.

(2) Monitoring of environmental effects shall include determination of the spatial and temporal environmental changes induced by the exploration, testing, development, production, and processing activities on the flora and fauna of the sea surface, the water column, and/or the seafloor.

(3) The Director may place observers onboard exploration, testing, mining, and processing vessels; installations; or structures to ensure that the provisions of the lease, the approved plan, and these regulations are followed and to evaluate the effectiveness of the approved monitoring and mitigation practices and procedures in protecting the environment.

(4) The Director may order or the lessee may request a modification of the approved monitoring program prior to the startup of testing activities or commercial-scale recovery, and at other appropriate times as necessary,

to reflect accurately the proposed operations or to incorporate the results of recent research or improved monitoring techniques.

(5) When prototype test mining is proposed, the lessee shall include a monitoring strategy for assessing the impacts of the testing activities and for developing a strategy for monitoring commercial-scale recovery and mitigating the impacts of commercial-scale recovery more effectively. At a minimum, the proposed monitoring activities shall address specific concerns expressed in the lease-sale environmental analysis.

(6) When required, the monitoring plan shall specify:

(i) The sampling techniques and procedures to be used to acquire the needed data and information;

(ii) The format to be used in analysis and presentation of the data and information;

(iii) The equipment, techniques, and procedures to be used in carrying out the monitoring program; and

(iv) The name and qualifications of person(s) designated to be responsible for carrying out the environmental monitoring.

(d) Lessees shall develop and conduct their operations in a manner designed to avoid, minimize, or otherwise mitigate environmental impacts and to demonstrate the effectiveness of efforts to that end. Based upon results of the monitoring program, the Director may specify particular procedures for mitigating environmental impacts.

(e) In the event that equipment or procedural failure might result in significant additional damage to the environment, the lessee shall submit a Contingency Plan which specifies the procedures to be followed to institute corrective actions in response to such a failure and to minimize adverse impacts on the environment. Such procedures shall be designed for the site and mining activities described in the approved Delineation, Testing, or Mining Plan.

§ 282.29 Reports and records.

(a) A report of the amount and value of each OCS mineral produced from each lease shall be made by the payor for the lease for each calendar month, beginning with the month in which approved testing, development, or production activities are initiated and shall be filed in duplicate with the Director on or before the 20th day of the succeeding month, unless an extension of time for the filing of such report is granted by the Director. The report shall disclose accurately and in detail all operations conducted during each month and present a general summary of the status of leasehold activities. The report shall be submitted each month until the lease is terminated or relinquished unless the Director authorizes omission of the report during an approved suspension of production. The report shall show for each calendar month the location of each mining and processing activity; the number of days operations were conducted; the identity, quantity, quality, and value of each OCS mineral produced, sold, transferred, used or otherwise disposed of; identity, quantity, and quality of an inventory maintained prior to the point of royalty determination; and other information as may be required by the Director.

(b) The lessee shall submit a status report on exploration and/or testing activities under an approved Delineation or Testing Plan to the Director within 30 days of the close of each calendar quarter which shall include:

(1) A summary of activities conducted;

(2) A listing of all geophysical and geochemical data acquired and developed such as acoustic or seismic profiling records;

(3) A map showing location of holes drilled and where bottom samples were taken; and

(4) Identification of samples analyzed.

(c) Each lessee shall submit to the Director a report of exploration and/or testing activities within 3 months after the completion of operations. The final report of exploration and/or testing activities conducted on the lease shall include:

(1) A description of work performed;

(2) Charts, maps, or plats depicting the area and leases in which activities were conducted specifically identifying the lines of geophysical traverses and/

or the locations where geological activity was conducted and/or the locations of other exploration and testing activities;

(3) The dates on which the actual operations were performed;

(4) A narrative summary of any mineral occurrences; environmental hazards; and effects of the activities on the environment, aquatic life, archaeological resources, or other uses and users of the area in which the activities were conducted;

(5) Such other descriptions of the activities conducted as may be specified by the Director; and

(6) Records of all samples from core drilling or other tests made on the lease. The records shall be in such form that the location and direction of the samples can be accurately located on a map. The records shall include logs of all strata penetrated and conditions encountered, such as minerals, water, gas, or unusual conditions, and copies of analyses of all samples analyzed.

(d) The lessee shall report the results of environmental monitoring activities required in § 282.28 of this part and shall submit such other environmental data as the Director may require to conform with the requirements of these regulations.

(e)(1) All maps shall be appropriately marked with reference to official lease boundaries and elevations marked with reference to sea level. When required by the Director, vertical projections and cross sections shall accompany plan views. The maps shall be kept current and submitted to the Director annually, or more often when required by the Director. The accuracy of maps furnished shall be certified by a professional engineer or land surveyor.

(2) The lessee shall prepare such maps of the leased lands as are necessary to show the geological conditions as determined from G&G surveys, bottom sampling, drill holes, trenching, dredging, or mining. All excavations shall be shown in such manner that the volume of OCS minerals produced during a royalty period can be accurately ascertained.

(f) Any lessee who acquires rock, mineral, and core samples under a lease shall keep a representative split of each geological sample and a quarter longitudinal segment of each core for 5 years during which time the samples shall be available for inspection at the convenience of the Director who may take cuts of such cores, cuttings, and samples.

(g)(1) The lessee shall keep all original data and information available for inspection or duplication, by the Director at the expense of the lessor, as long as the lease continues in force. Should the lessee choose to dispose of original data and information once the lease has expired, said data and information shall be offered to the lessor free of costs and shall, if accepted, become the property of the lessor.

(2) Navigation tapes showing the location(s) where samples were taken and test drilling conducted shall be retained for as long as the lease continues in force.

(h) Lessees shall maintain records in which will be kept an accurate account of all ore and rock mined; all ore put through a mill; all mineral products produced; all ore and mineral products sold, transferred, used, or otherwise disposed of and to whom sold or transferred, and the inventory weight, assay value, moisture content, base sales price, dates, penalties, and price received. The percentage of each of the mineral products recovered and the percentages lost shall be shown. The records associated with activities on a lease shall be available to the Director for auditing.

(i) When special forms or reports other than those referred to in the regulations in this part may be necessary, instructions for the filing of such forms or reports will be given by the Director.

§ 282.30 Right of use and easement.

(a) A right of use and easement that includes any area subject to a lease issued or maintained under the Act shall be granted only after the lessee has been notified by the requestor and afforded the opportunity to comment on the request. A holder of a right under a right of use and easement shall exercise that right in accordance with the requirements of the regulations in this part. A right of use and easement shall be exercised only in a manner which

does not interfere unreasonably with operations of any lessee on its lease.

(b) Once a right of use and easement has been exercised, the right shall continue, beyond the termination of any lease on which it may be situated, as long as it is demonstrated to the Director that the right of use and easement is being exercised by the holder of the right and that the right of use and easement continues to serve the purpose specified in the grant. If the right of use and easement extends beyond the termination of any lease on which the right may be situated or if it is situated on an unleased portion of the OCS, the rights of all subsequent lessees shall be subject to such right. Upon termination of a right of use and easement, the holder of the right shall abandon the premises in the same manner that a lessee abandons activities on a lease to the satisfaction of the Director.

§ 282.31 Suspension of production or other operations.

A lessee may submit a request for a suspension of production or other operations. The request shall include justification for granting the requested suspension, a schedule of work leading to the initiation or restoration of production or other operations, and any other information the Director may require.

Subpart D—Payments

§ 282.40 Bonds.

(a) Pursuant to the requirements for a bond in § 281.33 of this title, prior to the commencement of any activity on a lease, the lessee shall submit a surety or personal bond to cover the lessee's royalty and other obligations under the lease as specified in this section.

(b) All bonds furnished by a lessee or operator must be in a form approved by the Associate Director for Offshore Minerals Management. A single copy of the required form is to be executed by the principal or, in the case of surety bonds, by both the principal and an acceptable surety.

(c) Only those surety bonds issued by qualified surety companies approved by the Department of the Treasury shall be accepted. (See Department of Treasury Circular No. 570 and any supplemental or replacement circulars.)

(d) Personal bonds shall be accompanied by a cashier's check, certified check, or negotiable U.S. Treasury bonds of an equal value to the amount specified in the bond. Negotiable Treasury bonds shall be accompanied by a proper conveyance of full authority to the Director to sell such securities in case of default in the performance of the terms and conditions of the lease.

(e) A bond in the minimum amount of $50,000 to cover the lessee's obligations under the lease shall be submitted prior to the commencement of any activity on a leasehold. A $50,000 bond shall not be required on a lease if the lessee already maintains or furnishes a $300,000 bond conditioned on compliance with the terms of leases for OCS minerals other than oil, gas, and sulphur held by the lessee on the OCS for the area in which the lease is located. A bond submitted pursuant to § 256.58(a) of this chapter may be amended to include the aforementioned condition for compliance. Prior to approval of a Delineation, Testing, or Mining Plan, the bond amount shall be adjusted, if appropriate, to cover the operations and activities described in the proposed plan.

(f) For the purposes of this section there are four areas:

(1) The Gulf of Mexico;

(2) The area offshore the Pacific Coast States of California, Oregon,Washington, and Hawaii;

(3) The area offshore the coast of Alaska; and

(4) The area offshore the Atlantic coast.

(g) A separate bond shall be required for each area. An operator's bond may be submitted for a specific lease(s) in the same amount as the lessee's bond(s) applicable to the lease(s) involved.

(h) Where, upon a default, the surety makes a payment to the United States of an obligation incurred under a lease, the face amount of the surety bond and the surety's liability thereunder shall be reduced by the amount of such payment.

(i) After default, the principal shall, within 6 months after notice or within such shorter period as may be fixed by

the Director, either post a new bond or increase the existing bond to the amount previously held. In lieu thereof, the principal may, within that time, file separate or substitute bonds for each lease. Failure to meet these requirements may result in a suspension of operations including production on leases covered by such bonds.

(j) The Director shall not consent to termination of the period of liability of any bond unless an acceptable alternative bond has been filed or until all the terms and conditions of the lease covered by the bond have been met.

[54 FR 2067, Jan. 18, 1989, as amended at 62 FR 27960, May 22, 1997]

EFFECTIVE DATE NOTE: At 62 FR 27960, May 22, 1997, § 282.40 was amended by revising the first sentence of paragraph (b), effective Aug. 20, 1997. For the convenience of the user, the superseded text is set forth as follows:

§ 282.40 Bonds.

* * * * *

(b) All bonds furnished by a lessee or operator shall be in a form or on a form approved by the Director.* * *

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§ 282.41 Method of royalty calculation.

In the event that the provisions of royalty management regulations do not apply to the specific commodities produced under regulations in this part, the lessee shall comply with procedures specified in the leasing notice.

§ 282.42 Payments.

Rentals, royalties, and other payments due the Federal Government on leases for OCS minerals shall be paid and reports submitted by the payor for a lease in accordance with § 281.26 of this title.

Subpart E—Appeals

§ 282.50 Appeals.

Orders or decisions issued under the regulations in this part may be appealed in accordance with the provisions of part 290 of this title. The filing of an appeal with the Director shall not suspend the requirement for compliance with an order or decision other than the payment of a civil penalty.

SUBCHAPTER C—APPEALS

PART 290—APPEALS PROCEDURES

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290.1 Scope.
290.2 Who may appeal.
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290.4 Oral argument.
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290.6 Appeals to the Commissioner of Indian Affairs.
290.7 Appeals to the Board of Land Appeals.

AUTHORITY: R.S. 463, 25 U.S.C. 2; R.S. 465, 25 U.S.C. 9; sec. 32, 41 Stat. 450, 30 U.S.C. 189; sec. 5, 44 Stat. 1058, 30 U.S.C. 285; sec. 10, 61 Stat. 915, 30 U.S.C. 359; sec. 5, 6, 67 Stat. 464, 465, 43 U.S.C. 1334, 1335; sec. 24, 84 Stat. 1573, 30 U.S.C. 1023; 30 U.S.C. 1751.

SOURCE: 38 FR 10001, Apr. 23, 1973, unless otherwise noted.

§290.1 Scope.

The rules and procedures set forth herein apply to appeals to the Director, Minerals Management Service (and the Commissioner of Indian Affairs when Indian lands are involved) from final orders or decisions of officers of the Minerals Management Service, issued under authority of the regulations in chapter II of this title, 43 CFR part 23, 43 CFR subtitle B, chapter II, and 25 CFR part 177. This part also provides for the further right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary, from adverse decisions of the Director (and the Commissioner of Indian Affairs when Indian lands are involved) rendered under this part.

[38 FR 10001, Apr. 23, 1973, as amended at 47 FR 28370, June 30, 1982]

§290.2 Who may appeal.

Any party to a case adversely affected by a final order or decision of an officer of the Minerals Management Service shall have a right to appeal to the Director, Minerals Management Service, unless the decision was approved by the Secretary or the Director prior to promulgation.

[38 FR 10001, Apr. 23, 1973, as amended at 47 FR 28370, June 30, 1982]

§290.3 Appeals to Director.

(a)(1) An appeal to the Director, Minerals Management Service, may be taken by filing a notice of appeal in the office of the official issuing the order or decision within 30 days from service of the order or decision. The notice of appeal shall incorporate or be accompanied by such written showing and argument on the facts and laws as the appellant may deem adequate to justify reversal or modification of the order or decision. Within the same 30-day period, the appellant will be permitted to file in the office of the official issuing the order or decision additional statements of reasons and written arguments or briefs.

(2) No extension of time will be granted for filing the notice of appeal. If the notice is filed after the grace period provided in §290.5(b) of this title and the delay in filing is not waived, as provided by that section, the notice of appeal will not be considered and the case will be closed.

(b) The officer with whom the appeal is filed shall transmit the appeal and accompanying papers to the Director, Minerals Management Service, with a full report and his recommendation on the appeal.

(c) The Director will review the record and render a decision in the case.

[38 FR 10001, Apr. 23, 1973, as amended at 54 FR 52797, Dec. 22, 1989]

§290.4 Oral argument.

Oral argument in any case pending before the Director, Minerals Management Service, will be allowed on motion in the discretion of such officer and at a time to be fixed by him.

§290.5 Time limitations.

(a) With the exception of the time fixed for filing a notice of appeal, the time for filing any document in connection with an appeal may be extended by the Director, Minerals Management Service. A request for an extension of time must be filed within

the time allowed for filing of the document and must be filed in the same office in which the document in connection with which the extension is requested must be filed.

(b) A notice of appeal must be filed within the time provided in § 290.3 of this title. If the notice of appeal is not received in the proper office within that time, the delay in filing will be waived if the notice of appeal is filed not later than 10 days after it was required to be filed and it is determined that the notice of appeal was transmitted to the proper office before the end of the time required for filing in § 290.3(a)(1) of this title. Determinations under this paragraph shall be made by the officer with whom the notice of appeal is required to be filed.

[38 FR 10001, Apr. 23, 1973, as amended at 54 FR 52797, Dec. 22, 1989]

§ 290.6 Appeals to the Commissioner of Indian Affairs.

The procedure for appeals under this part shall be followed for permits and leases on Indian land except that with respect to such permits and leases, the Commissioner of Indian Affairs will exercise the functions vested in the Director, Minerals Management Service.

§ 290.7 Appeals to the Board of Land Appeals.

Any party to a case adversely affected by a final decision of the Director, Minerals Management Service, or the Commissioner of Indian Affairs under this part shall have a right of appeal to the Board of Land Appeals in the Office of Hearings and Appeals, Office of the Secretary, in accordance with the procedures provided in 43 CFR part 4, ''Department Hearings and Appeals Procedures.''

CHAPTER III—BOARD OF SURFACE MINING AND RECLAMATION APPEALS, DEPARTMENT OF THE INTERIOR

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PART 301—PROCEDURES UNDER SURFACE MINING CONTROL AND RECLAMATION ACT OF 1977

AUTHORITY: Sec. 201, Pub. L. 95–87, 91 Stat. 445, 30 U.S.C. 1201 et seq.

§ 301.1 Cross reference.

For special rules applicable to hearings, appeals, and other review procedures relating to surface mining control and reclamation within the jurisdiction of administrative law judges and the Interior Board of Surface Mining and Reclamation Appeals, Office of Hearings and Appeals, see Subpart L of part 4 of subtitle A—Office of the Secretary of the Interior, of title 43 CFR. Subpart A of part 4 and all of the general rules in subpart B of part 4 not inconsistent with the special rules in subpart L of part 4 are also applicable to such hearings, appeals and other review proceedings.

[43 FR 41974, Sept. 19, 1978]

CHAPTER IV—GEOLOGICAL SURVEY, DEPARTMENT OF THE INTERIOR

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PART 401—STATE WATER RESEARCH INSTITUTE PROGRAM

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401.26 Evaluation of institutes.

AUTHORITY: 42 U.S.C. 10303.

SOURCE: 50 FR 23114, May 31, 1985, unless otherwise noted.

Subpart A—General

§ 401.1 Purpose.

The regulations in this part are issued pursuant to title I of the Water Research Act of 1984 (Pub. L. 98–242, 98 Stat. 97) which authorizes appropriations to, and confers authority upon, the Secretary of the Interior to promote a national program of water-resources research.

§ 401.2 Delegation of authority.

The State Water Research Institute Program, as authorized by section 104 of the Act, has been established as a component of the U.S. Geological Survey (USGS). Secretary of the Interior has delegated to the Director of the USGS authority to take the actions and make the determinations that, under the Act, are the responsibility of the Secretary.

§ 401.3 Definitions.

Act means the Water Resources Research Act of 1984 (Pub. L. 98–242, 98 Stat. 97).

Fiscal year means a 12-month period ending on September 30.

Director means the Director of the USGS or a designee.

Grant means the funds made available to an institute in a particular fiscal year pursuant to section 104 of the Act and the regulations in this chapter.

Grantee means the college or university at which an institute is established.

Granting agency means the USGS.

Institute means a water resources research institute, center, or equivalent agency established in accordance with Title I of the Act.

Region means any grouping of two or more institutes mutually chosen by themselves to reflect a commonality of water-resources problems.

Scientists means individuals engaged in any professional discipline, including the life, physical or social sciences, and engineers.

Secretary means the Secretary of the Interior or a designee.

State means each of the 50 States, the Commonwealth of Puerto Rico, the Virgin Islands, the District of Columbia, Guam, American Samoa, the Commonwealth of the Mariana Islands, and the Federated States of Micronesia.

[50 FR 23114, May 31, 1985, as amended at 58 FR 27204, May 7, 1993]

§ 401.4 Information collection.

(a) The information collection requirements contained in sections 401.11 and 401.19 have been approved by the Office of Management and Budget under 44 U.S.C. 3501 et seq. and assigned clearance number 1028–0044. The information will be used to support water related research and provide performance reports on accomplishments achieved under Pub. L. 98–242, 98 Stat. 97 (42 U.S.C. 10303). This information allows the agency to determine compliance with the objectives and criteria of the grant programs. Response is mandatory in accordance with 30 CFR 401.11 and 401.19.

(b) Public reporting burden for the collection of information is estimated to average 84 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate, or any other suggestions for reducing the burden, to Paperwork Management Officer, U.S. Geological Survey, Paperwork Management Section MS 208, Reston, Virginia 22092 and the Office of Management and Budget, Paperwork Reduction Project (1028–0044), Washington, DC 20503.

[58 FR 27204, May 7, 1993]

§ 401.5 [Reserved]

Subpart B—Designation of Institutes; Institute Programs

§ 401.6 Designation of institutes.

(a) As a condition of recognition as an established institute under the provisions of this chapter, each institute shall provide to the Director written evidence that it conforms to the requirements of subsection 104(a) of the Act, in that:

(1) The institute is established at the college or university in the State that was established in accordance with the Act of July 21, 1862 (12 Stat. 503; 7 U.S.C. 301ff), *i.e.*, a ''land-grant'' institution, or;

(2) If established at some other institution, the institute is at a college or university that has been designated by act of the legislature for the purposes of the Act, or;

(3) If there is more than one ''land-grant'' institution in the State, and no designation has been made according to paragraph (a)(2) of this section, the institute has been established at the one such institution designated by the Governor of the State to participate in the program, or;

(4) The institute has been designated as an interstate or regional institute by two or more cooperating States as provided in the Act.

(b) The certification of designation made pursuant to paragraph (a) of this section shall originate following the issuance of these regulations, be signed by the highest ranking officer of the college or university at which the institute is established and be submitted to the Director within 90 days of the effective date of these regulations. It shall be accompanied either by the evidence of establishment under the provisions of 30 CFR part 401 or by new evidence of establishment made pursuant to these regulations.

(c) Any institute not previously established under the provisions of the Water Resources Act of 1964 (Pub. L. 88–379, 78 Stat. 331) or the Water Research and Development Act of 1978 (Pub. L. 95–467, 92 Stat. 1305) shall also, in addition to the annual program application specified in § 401.11 of this chapter, submit to the Director the following information:

(1) Evidence of the appointment by the governing authority of the college or university of an officer to receive and account for all funds paid under the provisions of the Act and to make annual reports to the granting agency on work accomplished; and

(2) A management plan for meeting the requirements of the evaluation mandated by § 401.26.

[50 FR 23114, May 31, 1985, as amended at 58 FR 27204, May 7, 1993]

§ 401.7 Programs of institutes.

(a) Release of grant funds to participating institutes is conditioned on the ability of each receiving institute to plan, conduct, or otherwise arrange for:

(1) Competent research, investigations, and experiments of either a basic or practical nature, or both, in relation to water resources;

(2) Promotion of the dissemination and application of the results of these efforts; and

(3) Assistance in the training of scientists in relevant fields of endeavor to water resources through the research, investigations, and experiments.

(b) Such research, investigations, experiments and training may include:

(1) Aspects of the hydrologic cycle;

(2) Supply and demand;

(3) Demineralization of saline and other impaired waters;

(4) Conservation and best use of available supplies of water and methods of increasing such supplies;

(5) Water reuse;

(6) Depletion and degradation of ground-water supplies;

(7) Improvements in the productivity of water when used for agricultural, municipal, and commercial purposes;

(8) The economic, legal, engineering, social, recreational, biological, geographical, ecological, or other aspects of water problems;

(9) Scientific information dissemination activities, including identifying, assembling, and interpreting the results of scientific research on water resources problems, and ;

(10) Providing means for improved communication of research results, having due regard for the varying conditions and needs of the respective States and regions.

(c) An institute shall cooperate closely with other colleges and universities in the State that have demonstrated capabilities for research, information dissemination and graduate training in the development of its program. For purposes of financial management, reporting and other research program management and administration activities, the institutes shall be responsible for performance of the activities of other participating institutions.

(d) Each institute shall cooperate closely with other institutes and other research organizations in the region to increase the effectiveness of the institutes, to coordinate their activities, and to avoid undue duplication of effort.

§§ 401.8–401.10 [Reserved]

Subpart C—Application and Management Procedures

§ 401.11 Applications for grants.

(a) Subject to the availability of appropriated funds, but not to exceed a total of $10 million, an equal amount of dollars will be available to each qualified institute in each fiscal year to assist it in carrying out the purposes of the Act. If the full amount of the appropriated funds is not obligated by the close of the fiscal year for which they were appropriated, the remaining funds shall be made available in the succeeding fiscal year to support competitively selected research projects under the terms of section 104(g) of the Act. Selection and approval of such projects shall be based on criteria to be determined by the Director. Announcement of such criteria shall be made by notice in the FEDERAL REGISTER. The granting agency may retain an amount up to 15 percent of the total appropriation for administrative costs.

(b) The granting agency will annually make available to qualified institutes instructions for the submittal of applications for grants. The instructions will include information pertinent only to a single fiscal year, such as the closing date for applications and the amount of funds initially available to each institute. They also will include notification of the provisions and assurances necessary to ensure that administration of the grant will be conducted in compliance with this chapter and other Federal laws and regulations applicable to grants to institutions of higher learning.

(c) In making its application for funds to which it is entitled under the Act, each institute shall use and follow the standard form for Federal assistance (SF 424, Federal Assistance). No preapplication is required. The institute shall include in section IV of Standard Form 424 evidence that its application was:

(1) Developed in close consultation and collaboration with senior personnel of the State's department of water resources or similar agencies, other leading water resources officials within the State, and interested members of the public;

(2) Coordinated with other institutes in the region for the purposes of avoiding duplication of effort and encouraging regional cooperation in research areas of water management, development, and conservation that have a regional or national character; and

(3) Reviewed for technical merit of its research components by qualified scientists.

(d) Each application shall further include:

(1) A financial plan relating expenditures to scheduled activity and rate of effort to be expended and indicating the times at which there will be need for specified amounts of Federal funds; and

(2) A description of the institute's arrangements for development, administration, and technical oversight of the research program.

(e) Each annual program application is to include separately identifiable proposals for conduct of research to meet the needs of the State and region. Such proposals must set forth for each project:

(1) The nature, scope and objectives of the project to be undertaken;

(2) Its importance to the State, region, or Nation; its relation to other known research projects already completed or in progress; and the anticipated applicability of the research results;

(3) The period during which it will be pursued;

(4) The names and qualifications of the senior professional personnel who will direct and conduct the project;

(5) Its estimated costs, with a breakdown of the costs per year; and

(6) The extent of which it will provide opportunity for the training of scientists.

(f) Each program application shall contain a plan for disseminating information on the results of research and promoting their application. Plans which require the use of grant funds shall contain:

(1) Definition of the topics for dissemination;

(2) Identification of the target audiences for dissemination;

(3) Strategies for accomplishing the dissemination;

(4) Duties and qualifications of the personnel to be involved;

(5) Estimated costs of each identifiable element of the plan; and

(6) Identification of cooperating entities.

(g) The application shall provide assurance that non-Federal dollars will be available to share the costs of the proposed program. The Federal funds are to be matched on a basis of no less than two non-Federal dollars for each Federal dollar, unless this matching requirement has been waived.

(h) The granting agency will evaluate the proposals for consistency with the provisions of its instructions and this chapter and within no more than 90 days request any revisions and additions necessary for such consistency.

[50 FR 23114, May 31, 1985, as amended at 58 FR 27204, May 7, 1993]

§ 401.12 Program management.

(a) Upon approval of each fiscal year's proposed program, the granting agency will transmit to the grantee an award which will incorporate the application and assurances.

(b) The grant is effective and constitutes an obligation of Federal funds in the amount and for the purpose stated in the award document at the time of the Director's signature.

(c)(1) Acceptance of the award document certifies the grantee's assurance that the grant will be administered in compliance with OMB regulations, policies, guidelines, and requirements as described in:

(i) Circular No. A–21, revised, Cost Principles of Educational Institutions;

(ii) Memorandum No. M–92–01, Coordination of Water Resources Information;

(iii) Circular No. A–88, revised, Indirect Cost Rates, Audit and Audit Follow-up at Educational Institutions;

(iv) Circular No. A–110, Uniform Administrative Requirements for Grants and Agreements with Institutions of Higher Education, Hospitals and other Nonprofit Organizations; and

(v) Circular No. A–124, Patents—Small Business Firms and Nonprofit Organizations.

(2) Copies of the documents listed in paragraph (c)(1) of this section shall be available from the granting agency.

[50 FR 23114, May 31, 1985, as amended at 58 FR 27204, May 7, 1993]

§§ 401.13–401.18 [Reserved]

Subpart D—Reporting

§ 401.19 Reporting procedures.

(a) The institutes are encouraged to publish, as technical reports or in the professional literature, the findings, results, and conclusions relating to separately identifiable research projects undertaken pursuant to the Act.

(b) Each institute shall submit to the granting agency, by a date to be specified in the award document, an annual program report which provides:

(1) A statement concerning the relationship of the institute's program to the water problems and issues of the State;

(2) A synopsis of the objectives, methods, and conclusions of each project completed within the period covered;

(3) A progress report on each project continuing into the subsequent fiscal year;

(4) Citations of all reports, papers, publications or other communicable products resulting from each project completed or in progress;

(5) A description of all activities undertaken for the purpose of promoting the application of research results;

(6) A description of cooperative arrangements with other educational institutions, State agencies, and others.

(c) One manuscript of reproducible quality and two copies of the annual program report shall be furnished to the granting agency. One copy of a complete report on the objectives, methods, and conclusions of each research project shall be maintained by the institute and open to inspection.

(d) Appropriate acknowledgment shall be given by institutes to the granting agency's participation in financing activities carried out under provisions of the Act. Such acknowledgment shall be included in all reports, publications, news releases, and other information media developed by institutes and others to publicize, describe, or report upon accomplishments and activities of the program.

(e) An original and two copies of the final ''Financial Status Report,'' SF 269, shall be furnished to the granting agency within 90 days of completion of the grant period.

§§ 401.20–401.25 [Reserved]

Subpart E—Evaluation

§ 401.26 Evaluation of institutes.

(a) Within 2 years of the date of its certification according to the provisions of § 401.6, each institute will be evaluated for the purpose of determining whether the national interest warrants its continued support under the provisions of the Act. That determination shall be based on:

(1) The quality and relevance of its water resources research as funded under the Act;

(2) Its effectiveness as an institution for planning, conducting, or arranging for research;

(3) Its demonstrated performance in making research results available to users in the State and elsewhere; and

(4) Its demonstrated record in providing for the training of scientists through student involvement in its research program.

(b) An evaluation team, selected by the granting agency on the basis of the members' knowledge of water research and administration, shall evaluate each institute, and may with the concurrence of the granting agency, visit such institutes as it considers necessary. The team is to include at least one individual from each of the following categories:

(1) Employees of the Department of the Interior;

(2) University faculty or other professionals with relevant experience in the conduct of water resources research;

(3) Former directors of water research institutes; and

(4) University faculty or other professionals with relevant experience in information transfer.

(c) The granting agency may request recommendations for team selections from the National Research Council/National Academy of Sciences and from other organizations whose members include the types of individuals cited in paragraph (b) of this section.

(d) The granting agency shall, as an administrative cost, provide the funds for travel and per diem expense of the team members, within the maximum limits allowable under Federal travel regulations (41 CFR subtitle F).

(e) The granting agency has the right to select dates for evaluation visits, and notice of the team's visit shall be provided to the institute being evaluated at least 60 days in advance.

(f) It shall be the responsibility of each institute to provide such documentation of its activities and accomplishments as the granting agency and

evaluation team may reasonably request. The request for this documentation shall be made at least 60 days prior to the due date of its receipt.

(g) The team shall, within 90 days after completion of its evaluation, submit a written report of its findings to the granting agency for transmittal to the institute. If an institute is found to have deficiencies in meeting the objectives of the Act, it shall be allowed 1 year to correct them and to report such action to the granting agency. The decision as to the institute's eligibility to receive further funding will rest with the granting agency.

(h) After the initial evaluation, each institute shall be reevaluated at least every 5 years.

[58 FR 27204, May 7, 1993]

PART 402—WATER-RESOURCES RESEARCH PROGRAM AND THE WATER-RESOURCES TECHNOLOGY DEVELOPMENT PROGRAM

Subpart A—General

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402.2 Delegation of authority.
402.3 Definitions.
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402.5 [Reserved]

Subpart B—Description of Water-Resources Programs

402.6 Water-Resources Research Program.
402.7 Water-Resources Technology Development Program.
402.8—402.9 [Reserved]

Subpart C—Application, Evaluation, and Management Procedures

402.10 Research project applications.
402.11 Technology-development project applications.
402.12 Evaluation of applications for grants and contracts.
402.13 Program management.
402.14 [Reserved]

Subpart D—Reporting

402.15 Reporting procedures.

SOURCE: 51 FR 20963, June 10, 1986, unless otherwise noted.

AUTHORITY: Secs. 105 and 106, Pub. L. 98–242, 98 Stat. 97 (42 U.S.C. 10304 and 10305).

Subpart A—General

§ 402.1 Purpose.

The regulations in this part are issued pursuant to title I of the Water Resources Research Act of 1984 (Pub. L. 98–242, 98 Stat. 97), which authorizes appropriations to, and confers authority upon, the Secretary of the Interior to promote national programs of water-resources research and technology development.

§ 402.2 Delegation of authority.

The Water-Resources Research Program and the Water-Resources Technology Development Program, as authorized by sections 105 and 106 of the Act (42 U.S.C. 10304 and 10305), have been established as components of the USGS. The Secretary of the Interior has delegated to the Director of the USGS authority to take actions and make the determinations that, under the Act, are the responsibility of the Secretary.

§ 402.3 Definitions.

(a) *Grant* is used in these rules as a generic term for a Federal assistance award, including project grants and cooperative agreements.

(b) *Act* means the Water Resources Research Act of 1984 (Pub. L. 98–242, 98 Stat. 97).

(c) *Educational institution* means any educational institution—privately and/or publicly owned.

(d) *Dollar-for-dollar matching grant* means for each Federal dollar provided to support the projects, a non-Federal dollar also must be provided to the project.

§ 402.4 Information collection.

The information-collection requirements contained in sections 402.10, 402.11, and 402.15 have been approved by the OMB under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1028–0046. The application proposals being collected will contain technical information that will be used by the USGS as a basis for selection and award of grants. The progress reports being collected will contain a description of all work accomplished and results achieved on each funded project and will enable the USGS to carry out its

oversight responsibilities and provide dissemination of technical information.

§ 402.5 [Reserved]

Subpart B—Description of Water-Resources Programs

§ 402.6 Water-Resources Research Program.

(a) Subject to the availability of appropriated funds, the Water-Resources Research Program will provide support, in the form of a dollar-for-dollar matching grant, to educational institutions, private foundations, private firms, individuals, and agencies of local or State governments for research concerning any aspect of a water-resource related problem deemed to be in the national interest. Federal agencies are excluded from receiving matching grants. Grants may be awarded on other than a dollar-for-dollar matching basis in cases where the USGS determines that research on a high-priority subject is of a basic nature that otherwise would not be undertaken.

(b) The types of research to be undertaken under this program are listed below, without indication of priority:

(1) Aspects of the hydrologic cycle;

(2) Supply and demand for water;

(3) Demineralization of saline and other impaired waters;

(4) Conservation and best use of available supplies of water and methods of increasing such supplies;

(5) Water reuse;

(6) Depletion and degradation of groundwater supplies;

(7) Improvements in the productivity of water when used for agricultural, municipal, and commercial purposes; and

(8) The economic, legal, engineering, social, recreational, biological, geographic, ecological, and other aspects of water problems.

(9) Scientific information-dissemination activities, including identifying, assembling, and interpreting the results of scientific and engineering research on water-resources problems.

(10) Providing means for improved communications of research results, having due regard for the varying conditions and needs for the respective States and regions.

§ 402.7 Water-Resources Technology Development Program.

(a) Subject to the availability of appropriated funds, the Water-Resources Technology Development Program will provide funds in the form of grants or contracts to educational institutions, private firms, private foundations, individuals, and agencies of local or State governments for technology development concerning any aspect of water-related technology deemed to be of State, regional, and national importance, including technology associated with improvement of waters of impaired quality and the operation of test facilities. Federal agencies are excluded from receiving grants or contracts. The types of technology-development to be undertaken under this program shall include paragraphs 1 through 10 of § 402.6(b).

(b) The USGS may establish any condition for the matching of funds by the recipient of any grant or cost-sharing under a contract under the technology-development program which the USGS considers to be in the best interest of the Nation.

§§ 402.8—402.9 [Reserved]

Subpart C—Application, Evaluation, and Management Procedures

§ 402.10 Research-project applications.

(a) Only those applications for grants that are in response to and meet the guidelines of specific USGS announcements will be considered for funding appropriated for this program.

(b) The USGS program announcements will identify priorities, matching requirements, particular areas of interest, criteria for evaluation, OMB regulations as appropriate, assurances, closing date, and proposal submittal instructions. Program announcements may also include criteria for high-priority subjects of a basic nature that may be funded on other than a dollar-for-dollar basis. Program announcements will be distributed to names on the current USGS mailing list for the

Water-Resources Research Program announcements, including new requests received in response to published notices of upcoming program announcements.

(c) Notification of the availability of the program announcement will be published in the Commerce Business Daily and/or FEDERAL REGISTER.

(d) The application for funds must be signed by an individual or official authorized to commit the applicant and it must contain:

(1) A Standard Form 424 ''Federal Assistance,'' sections I and II completed by applicant, used as the cover sheet for each proposal.

(2) A project summary of no more than one typed, single-spaced page providing the following specific information:

(i) Identification of the water or water-related problems and the problem-solution approach;

(ii) Identification of the proposed scientific contribution of the problem solution;

(iii) Concise statement of the specific objectives of the project;

(iv) Identification of the approach to be used to accomplish the work; and

(v) Identification of potential users of the proposed work.

(3) Narrative information, as specified in the published program announcement, such as project title, project objectives, background information, research tasks, methodology to conduct the research task, the relevancy of the proposed project to water-resources problems, qualifications of the principal investigators and their organizations, and proposed budget with supporting information sufficient to allow evaluation of costs.

§402.11 Technology-development project applications.

(a) Grant awards will be used to support those portions of the program for which the principal purpose is other than as described in §402.11(b). Program announcements and applications will be governed by the same procedures provided in §402.10.

(b) If it is determined that the principal purpose of a planned award (or awards) is to acquire goods or services for the direct benefit or use of the Government, the action must be regarded as a procurement contract. A competitive solicitation prepared in accordance with applicable acquisition regulations will be issued to interested parties. Notification of the availability of any contract solicitation will be published in the Commerce Business Daily, unless waived in accordance with §5.202 of the Federal Acquisition Regulation (FAR). Contracts may be awarded without full and open competition only if justified in accordance with FAR subpart 6.3.

§402.12 Evaluation of applications for grants and contracts.

(a) *Grants.* (1) Each grant application will receive technical evaluations from Government and/or non-Government scientific or engineering personnel. Utilizing the criteria for evaluation identified in the applicable announcement, each reviewer will assign a technical score.

(2) Grant applications with low technical ratings will be screened out, and the remaining grant applications will be rank-ordered by review panels.

(3) USGS program officials will compile a single, consolidated rank-ordered list of the grant applications based on technical scoring, program needs and published priorities, and the available Federal funds.

(b) *Contracts.* Proposals for contract awards will be evaluated by a USGS panel. Contracts will be awarded according to procedures contained in the FAR, the Department of the Interior Acquisition Regulation, and in acquisition policy releases issued by the Department and by the USGS.

§402.13 Program management.

(a) After the conclusion of negotiations, the USGS will transmit a grant or contract-award document, as appropriate, setting forth the terms of the award.

(b) *Grants.* Recipients will be required to execute funded projects in accordance with OMB Circulars governing cost principles, administrative requirements, and audit, as applicable to their organization type. In addition, OMB Circular A–67, Coordination of Federal Activities in the Acquisition of Certain

Water Data, is applicable to awards under these programs.

(c) *Contracts.* Administrative requirements for performance of research contracts will be established in the contract clauses in conformance with applicable procurement regulations and other interior or USGS acquisition policy documents. OMB Circular A–67 will also apply to some contract awards under this program.

§ 402.14 [Reserved]

Subpart D—Reporting

§ 402.15 Reporting procedures.

(a) Grantees or contractors will be required to submit the following technical reports to the USGS address identified under the terms and conditions of each award.

(1) *Quarterly Technical Progress Report.* This report shall include a description of all work accomplished, results achieved, and any changes that affect the project's scope of work, time schedule, and personnel assignments.

(2) *Draft Technical Completion Report.* The draft report will be required for review prior to submission of the final technical completion report.

(3) *Final Technical Completion Report.* The final report and a camera-ready copy shall be submitted to the USGS within 90 days after the expiration date of the award and shall include a summary of all work accomplished, results achieved, conclusions, and recommendations. The camera-ready copy shall be prepared in a manner suitable for reproduction by a photographic process. Format will be specified in the terms and conditions of the award.

(4) *Final Report Abstract.* A complete Water-Resources Scientific Information Center Abstract Form 102 and National Technical Information Service Form 79 shall be submitted with the final report.

(b) Grantees or contractors will be required to submit financial, administrative, and closeout reports as identified under the terms of each award. Reporting requirements will conform to the procedures described in the Departmental Manual of the Department of the Interior at 505 DM 1–5.

(c) Contracts for technology-development projects may also require delivery of hardware items produced and/or specifications, drawings, test results, or other data describing the funded technology.

CHAPTER VI—BUREAU OF MINES, DEPARTMENT OF THE INTERIOR

SUBCHAPTER A—HELIUM AND COAL

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SUBCHAPTER A—HELIUM AND COAL

PART 601—SALES OF HELIUM BY AND RENTAL OF CONTAINERS FROM THE BUREAU OF MINES

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601.2 Definitions.
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601.8 Settlements under existing contracts.
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601.10 [Reserved].
601.11 Applicability to Federal agencies.

AUTHORITY: Pub. L. 86–777, approved Sept. 13, 1960, 74 Stat. 918 (50 U.S.C. 167–167n).

SOURCE: 46 FR 37506, July 21, 1981, unless otherwise noted.

§ 601.1 Purpose.

The purpose of this part 601 is to establish procedures governing the sale of helium and related services by the Bureau of Mines, and the rental of helium containers from the Bureau of Mines.

§ 601.2 Definitions.

(a) *Act* means the Helium Act, Pub. L. 86–777, approved September 13, 1960 (74 Stat. 918; 50 U.S.C. 167–167n).

(b) [Reserved]

(c) *Helium plant* means a facility operated by or for the U.S. Bureau of Mines for the production, purification, repurification, or shipment of helium.

(d) *Bureau* means the Bureau of Mines of the Department of the Interior.

(e) *Purchaser* means any individual, corporation, partnership, firm, association, trust, estate, public or private institution, state or political subdivision thereof, having a new (after revision of this part) helium purchase contract with the Bureau, and any agency of the U.S. Government, purchasing helium from the Bureau or using helium containers rented from the Bureau.

(f) *Grade-A helium* means the grade of helium produced at the Bureau's helium plants, and is 99.995 percent pure helium, or better by volume.

(g) *Standard cubic foot (scf)* is a 1-cubic foot volume of Grade-A helium measured at a pressure of 14.7 pounds per square inch absolute and a temperature of 70° Fahrenheit.

(h) *Cylinder* means a standard-type cylinder of approximately 1.5 cubic feet internal volume, designed for a filling pressure of 1,800 pounds per square inch gage or more, which will stand vertically without external support with the center of the valve outlet not less than 50½ inches nor more than 58½ inches above the floor, equipped with a standard-type cylinder valve, safety relief device, and valve-protective cap, or a similar cylinder acceptable to the Bureau as a standard type.

(i) *Valve* means a standard-type cylinder valve acceptable to the Bureau of Mines having a valve outlet conforming to Specification No. 580 or No. 350 as described by the latest edition of Compressed Gas Association, Inc., Pamphlet V–1, ANSI B57.1–1977; *Provided*, That at the Bureau's option, valves with outlets conforming to other specifications may be accepted as alternate standards.

(j) *Tank car* means a railroad car permanently equipped with multiple tubes manufactured in accordance with 49 CFR 179.500.

(k) *Tube trailer* means a road-type semitrailer without motive power permanently equipped with multiple tubes manufactured in accordance with 49 CFR 178.36, 178.37, or 178.45.

(l) *Tube module* means one or more seamless steel tubes, manufactured in accordance with 49 CFR 179.500, that by means of a framework are joined together to form a unit. Valves may be manifolded.

(m) *Liquid helium trailer* means a special road-type semitrailer without motive power, equipped with a vacuum-jacketed container suitable for transporting 1,000 U.S. gallons or more of liquid helium. The container may be separable or an integral part of the chassis and dependent upon design, may or may not require a Department of Transportation (DOT) special permit for transporting.

(n) *Liquid helium dewar (dewar)* means a portable or skid-mounted, vacuum-jacketed container suitable for shipping less than 1,000 U.S. gallons of liquid helium.

(o) *Schedule of Prices and Charges (Schedule)* means a listing of prices and charges for products and services provided under contract pursuant to this part.

(p) *Federal Agency* is any department, independent establishment, commission, administration, foundation, authority, board, or bureau of the U.S. Government, or any corporation owned, controlled, or in which the U.S. Government has a proprietary interest, as these terms are defined in 5 U.S.C. 101–05; 5 U.S.C. 551(1); 5 U.S.C. 552(e); or in 18 U.S.C. 6, but does not include Federal agency contractors.

(q) *Contracting officer* is the person executing a contract on behalf of the Government, and includes any duly appointed successor.

§601.3 Contract application forms and procedures.

(a) Any prospective helium purchaser may make application to the Bureau to become a purchaser of helium, and, if desired, rent containers from the bureau and, upon meeting the requirements of this part and upon execution of a purchase (and container rental) contract with the Bureau, may purchase helium (and rent containers) from the Bureau. To be eligible, a prospective purchaser must: demonstrate adequate financial resources to pay for helium and helium-related services in advance, hold a certificate of competency and/or a determination of eligibility from the Small Business Administration if the prospective purchaser is a small business concern and is determined to be nonresponsible and/or ineligible by the contracting officer, and be otherwise qualified and eligible to enter into a Bureau contract under applicable laws and regulations.

(b) The information collection requirement contained in this paragraph has been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1032–0111. The information is being collected to identify firms desiring to enter into a contract. This information will be used to complete contract documents and establish cash advance required. The obligation to respond is required to obtain a benefit.

(c) The contract shall include, among other things, duties and responsibilities of the parties, definitions, term, minimum contract volume, and other conditions, such as advance payments, deposits, surety bonds, repurchase rights of the Government, liabilities, reservations with respect to sales and deliveries, power of inspection, notification to repurchasers, violations and penalties, cancellation and assignment of contract, termination, general provisions, and standard provisions.

(d) Application forms are available upon written request from Division of Helium Operations, 1100 S. Fillmore St., Amarillo, Texas 79101. Applicable contract form(s) and Schedule will be included for examination by the prospective purchaser.

(e) Upon approval by the Contracting Officer of the returned application, the contract will become effective when executed by both parties.

§601.4 [Reserved]

§601.5 Schedule of prices and charges.

(a) The Schedule of Prices and Charges (Schedule) is published by the Bureau of Mines, Division of Helium Operations, and is periodically updated. The Schedule is available upon request from the Division of Helium Operations, 1100 S. Fillmore St., Amarillo, Texas 79101, telephone 806–376–2638 or FTS 735–1638. The Schedule shows prices and charges for helium, ordinary related services, use or rental of Bureau-owned helium containers or equipment, cash advance, and deposit required, and bonds and/or insurance to guarantee return of containers.

(b) Terms and conditions under which products and services can be acquired under contract pursuant to this part are shown in appendix 1 to the Schedule. The terms and conditions are reviewed at least annually, and are revised as required.

(c) Revisions to the Schedule are determined at least annually by the Division of Helium Operations in accordance with Office of Management and

Budget (OMB) Circular No. A–25, as revised. In no case will a revised Schedule become effective in less than 30 days after date of distribution to all Bureau helium customers known at the time of distribution.

§ 601.6 Purchase price of helium.

(a) The purchase price of Grade-A helium shipped f.o.b. origin shall be the price stated in the Schedule that is in effect on the date the helium is shipped from the helium plant.

(b) [Reserved]

(c) The purchase price of Grade-A helium shipped f.o.b. destination shall be the price stated in the Schedule that is in effect on the date the helium is shipped from the helium plant plus any service charges, container charges, transportation charges, and other charges incurred in making such delivery. Delivery of helium f.o.b. destination is made only in Bureau-furnished containers.

§ 601.7 Service charges.

In addition to the purchase price of helium, the following charges for services and use of equipment rented from the Bureau shall be paid by the purchaser.

(a) *For filling containers.* The charge for filling helium containers shall be as shown in the Schedule that is in effect on the date the helium is shipped from the helium plant.

(b) *For ordinary work performed on containers supplied by the purchaser and for ordinary services performed in connection with shipment of helium from a helium plant.* The charge for ordinary work shall be as shown in the Schedule that is in effect on the date the work is performed.

(c) *For extraordinary expenses.* Such expenses incurred in connection with any contract or delivery for which prices are not stated in the effective Schedule including, but not limited to, costs of work on purchaser's containers, filling, servicing, and rental of containers of types other than those stated in the effective Schedule, purifying helium beyond normal plant purity, (delete ''liquefying helium'') analytical services, shipment of helium from other than a helium plant selected by the Bureau, and unusual handling, transportation, and communications, may be determined by the Bureau and charged to the purchaser as they arise on the basis of the cost of rendering the services, making due allowance for contingencies, overhead expense, and commercial common-carrier rates.

(d) *For use of helium containers supplied by the Bureau.* The charge for use of each Bureau-supplied container shall be as shown in the Schedule in effect on the date of shipment from a helium plant.

§ 601.8 Settlements under existing contracts.

Contracts for the purchase of helium or for the rent of Bureau-owned shipping containers which are in effect on the effective date of the amended regulations in this part shall remain in effect, subject to the terms and conditions of the amended regulations in this part, for a period of not more than 90 days after the effective date of these amended regulations or until replaced by new contract or contracts as described in these amended regulations, should such replacement occur prior to expiration of the 90 days. In the event that purchaser does not enter into replacement contract or contracts within 90 days after effective date of these regulations, the existing contract(s) shall terminate and purchaser shall pay any sums due Bureau under terms of the contracts and shall return any Bureau-owned shipping containers outstanding under any container rent contract so terminated.

§ 601.9 Shipping containers.

(a) *Containers may be provided by the purchaser or the Bureau.* The purchaser may provide containers or may request the Bureau to provide them under contract. Containers provided by the purchaser must be satisfactory to the Bureau in all respects, must be free internally from oil or water, and shall comply with the requirements for shipment in interstate commerce. The Bureau will not use or fill any container which in its opinion is unsafe or unsuitable.

(b) *Provisions applicable to all types of containers supplied by the Bureau.* Specific provisions for all types of containers, such as, cylinders, tank cars, tube

trailers, tube modules, liquid helium trailers, and liquid helium dewars, are detailed in the container rental contract and the Schedule.

§601.10 [Reserved]

§601.11 Applicability to Federal Agencies.

The regulations in this part are applicable to Federal agencies procuring helium or services from Bureau or using containers furnished by Bureau; *except that* Federal agencies shall not be required to: (a) enter into contracts for the purchase of helium or lease of containers, (b) furnish advance payments, or (c) provide surety for the return of containers or payment of bills.

PART 602—HELIUM DISTRIBUTION CONTRACTS

Sec.
602.1 Purpose.
602.2 Definitions.
602.3 Bureau helium distribution contracts.
APPENDIX TO PART 602

AUTHORITY: The Helium Act of 1960, Pub. L. 86–777 (50 U.S.C. 167, et seq.); 5 U.S.C. 301.

SOURCE: 46 FR 60436, Dec. 10, 1981, unless otherwise noted.

§602.1 Purpose.

The purpose of this part 602 is to establish procedures governing distribution of Bureau of Mines helium by a system of authorized private helium distributors. To the same end, the regulations prescribe certain requirements that must be met by private helium distributors under new contracts, entered into with the Bureau of Mines with an effective date of January 15, 1982, or later, to distribute Bureau of Mines helium.

§602.2 Definitions.

As used in this part—

(a) *Helium Act* means Pub. L. 86–777, 74 Stat. 918 (50 U.S.C. 167–167n).

(b) *Helium* means the element helium regardless of its physical state.

(c) *Bureau of Mines helium* or *Bureau helium* is helium, regardless of physical state or purity, available for purchase or purchased from the Secretary or a Bureau helium distribution contractor after the effective date of this revision of 30 CFR part 602. Bureau helium cannot be obtained from any other source of supply. Bureau of Mines helium includes volumes of helium available for delivery or delivered to the purchaser or Bureau helium distribution contractors in the Grade-A gaseous physical state or liquid physical state, and volumes of Grade-A gaseous helium used as raw stock to produce (1) liquid helium, and the liquid produced therefrom, (2) a gaseous or liquid mixture having a purity of helium different from Grade-A, (3) a gaseous or liquid mixture having a concentration of helium-4 isotope different from the concentration of such isotope in Grade-A helium, and (4) helium mixtures different in any other way from Grade-A gaseous helium. Bureau helium does not include private helium stored under contract with the Bureau and redelivered to the private enterprise in crude, Grade-A gaseous, or liquid helium form.

(d) *Grade-A helium* means the grade of helium produced at the Bureau's helium plants, and it is 99.995 percent pure helium or better, by volume.

(e) *Federal agency* means any department, independent establishment, commission, administration, foundation, authority, board, or bureau of the U.S. Government, or any corporation owned, controlled, or in which the U.S. Government has a proprietary interest, as these terms are defined in 5 U.S.C. 101–105; 5 U.S.C. 551 (1); 5 U.S.C. 552(e); or in 18 U.S.C. 6, but does not include Federal agency contractors.

(f) *Bureau helium distribution contractor* is a private helium merchant (as defined by the Texas Business and Commercial Code Ann., title 1, sec. 2.104 (Uniform Commercial Code)) that, by new contract with an effective date of January 15, 1982, or later with the Bureau, has Bureau helium available for distribution.

(g) *Private helium purchaser* means any individual, corporation, partnership, firm, association, trust, estate, public or private institution, state or political subdivision thereof, purchasing or wanting to purchase helium. The term does not include Federal agencies, but does include Federal agency contractors.

(h) *Helium requirement* or *requirement of helium* is all helium, regardless of physical state or in mixture with other gases, that is required by or delivered to a Federal agency to accomplish an objective, project, mission, or program of the Federal agency.

(i) *Major helium requirement* or *major requirement of helium* is a helium requirement or delivery of 5,000 standard cubic feet (scf), measured at 14.7 pounds per square inch absolute pressure and 70° Fahrenheit temperature, or more, including liquid helium gaseous equivalent, during a calendar month, including the first 5,000 scf per calendar month when the ''helium requirement'' equals or exceeds 5,000 scf per calendar month.

(j) *Secretary* is the Secretary of the Department of the Interior.

(k) *Bureau* is the Bureau of Mines of the U.S. Department of the Interior.

§ 602.3 Bureau helium distribution contracts.

(a) Any private helium merchant may make application to the Bureau to become a Bureau helium distribution contractor and, upon meeting the requirements of this part and upon execution of a three-year distribution contract with the Bureau, may become a Bureau helium distribution contractor. To be eligible, a prospective contractor must demonstrate: adequate financial resources to pay for Bureau helium and helium-related services in advance, adequate facilities and equipment to meet delivery schedules and quality standards required by purchasers of Bureau helium, a satisfactory record of performance in the distribution of helium, and/or other compressed gases, a certificate of competency and/or a determination of eligibility from the Small Business Administration if the prospective contractor is a small business concern and is determined to be nonresponsible and/or ineligible by the contracting officer, and be otherwise qualified and eligible to receive an award of a Bureau helium distribution contract under applicable laws and regulations. Effective January 15, 1982, and thereafter, only those helium merchants having a valid Bureau helium distribution contract shall be included on Bureau lists of Bureau helium distribution contractors. (The currently approved helium distribution contract is set out in the Appendix to this part.)

(b) The information collection requirements contained in this section have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance number 1032–0113. The information is being collected to identify firms desiring to become helium distribution contractors. This information will be used to determine responsible applicants as possible contractors, to establish an accountability of helium transfer between distributors, and to report distributor annual sales, transfers, and purchases of Bureau of Mines helium as certification of compliance with 30 CFR 602. The obligation to respond is required to obtain a benefit.

(c) Bureau helium distribution contracts shall require the Bureau helium distribution contractor to deliver only Bureau helium to supply (1) major helium requirements of any Federal agency, whether or not Bureau helium is specified by the agency, and (2) any helium requirement of any Federal agency if procurement documents in any manner specify or evidence intent to acquire Bureau helium. Information about which Federal agencies have major helium requirements is available from Bureau of Mines Division of Helium Operations, 1100 S. Fillmore St., Amarillo, Texas 79101, telephone 806 376–2638 or FTS 735–1638.

(d) Bureau helium distribution contracts shall also require the Bureau helium distribution contractor to deliver only Bureau helium to:

(1) Any private helium purchaser, including Federal agency contractors, if procurement documents in any manner specify or evidence intent to acquire Bureau helium, or

(2) Another Bureau helium distribution contractor if certification as Bureau helium is required or furnished.

(e) Contracts shall include provisions for sources of supply of Bureau helium, quantity, quality, delivery requirements, Bureau helium book inventory, actual physical volume of helium in inventory, commingling, accounting and reporting procedures, records and facilities examinations, shipping points, payments, and contract termination.

APPENDIX TO PART 602

Bureau Helium Distribution Contract No. 14–09–0060 ——— Between United States Department of the Interior, Bureau of Mines and ———

Contents

Preamble
Article I, Definitions
Article II, Term of Contract
Article III, Bureau Helium Distribution Contractor
Article IV, Bureau of Mines
Article V, Conditions
Article VI, General Provisions
Addendum ''A''—Application
Addendum ''B''—Certificate of Resale of Bureau of Mines Helium (Form HA–285a)
Addendum ''C''—Bureau of Mines Helium: Stocks, Receipts, and Distribution Annual Report (Form 6–1575–A(1–77) Rev.)

BUREAU HELIUM DISTRIBUTION

Contract

This contract, made this —— day of ———, 19—, pursuant to the Helium Act (Act of 1960, Pub. L. 86–777, 74 Stat. 918, 50 U.S.C. 167 et seq., 5 U.S.C. 301), between the United States of America, Department of the Interior, Bureau of Mines, hereinafter styled Bureau of Mines, represented by the officer executing this contract, and ———— whose principal address is ———— hereinafter styled Bureau Helium Distribution Contractor, or Contractor.

Witnesseth that:

Whereas, pursuant to provisions of the Helium Act: ''The Department of Defense, the Atomic Energy Commission, and other agencies of the Federal Government, to the extent that supplies are readily available, shall purchase all major requirements of helium from the Secretary,'' (of the Department of the Interior);

Whereas, the Bureau of Mines, by virtue of authority delegated by the ''Secretary'' (of the Department of the Interior) under the Helium Act administers the production and distribution of helium for Federal use;

Whereas, the authorization of private helium merchants to participate in the distribution of Bureau of Mines helium for Federal use is advantageous to both the United States Government and the private helium merchants; and

Whereas, an application to become a Bureau Helium Distribution Contractor, attached to and forming a part of this contract (Addendum A), has been received by the Bureau of Mines from the private helium, merchant named as a party to this contract.

Now Therefore, in consideration of the mutual and dependent covenants herein contained, it is mutually agreed between the parties as follows:

Article I—Definitions

1.1 *Bureau helium distribution contractor* is a private helium merchant (as defined by the Texas Business and Commercial Code Ann., Title 1, Sec. 2.104 (Uniform Commercial Code)) that by new contract with an effective date of January 15, 1982, or later with the Bureau, has Bureau helium available for distribution.

1.2 *Bureau* is the Bureau of Mines of the United States Department of the Interior.

1.3 *Bureau of Mines helium* or *Bureau helium* is helium, regardless of physical state or purity, available for purchase or purchased from the secretary or another Bureau helium distribution contractor after the effective date of this contract. Bureau helium cannot be obtained from any other source of supply. Bureau of Mines helium includes volumes of helium available for delivery or delivered to purchasers or Bureau helium distribution contractors in the Grade-A gaseous physical state or liquid physical state and volumes of Grade-A gaseous helium used as raw stock to produce (1) liquid helium and the liquid produced therefrom, (2) a gaseous or liquid mixture having a purity of helium different from Grade-A, (3) a gaseous or liquid mixture having a concentration of helium-4 isotope different from the concentration of such isotope in Grade-A helium, and (4) helium mixtures different in any other way from Grade-A gaseous helium. Bureau helium does not include private helium stored under contract with the Bureau and redelivered to the private enterprise (owner) in crude Grade-A gaseous, or liquid helium form.

1.4 *Contracting officer* is the person executing this contract on behalf of the Government and includes a duly appointed successor or authorized representative.

1.5 *Federal agency* is any department, independent establishment, commission, administration, foundation, authority, board, or bureau of the United States Government, or any corporation owned, controlled, or in which the United States Government has a proprietary interest, as these terms are defined in 5 U.S.C. 101–05; 5 U.S.C. 551(1); 5 U.S.C. 552(e); or in 18 U.S.C. 6, but does not include Federal agency contractors.

1.6 *Federal Agency Contractor* is any individual, corporation, partnership, firm, association, trust, estate, public or private institution, or a State or political subdivision thereof which has entered into or that is obligated by a contract or cooperative agreement with a Federal agency, or received a grant from a Federal agency, or which subcontracts with a Federal Agency Contractor.

1.7 *Private helium purchaser* means any individual, corporation, partnership, firm, association, trust, estate, public or private institution, state or political subdivision thereof, purchasing or wanting to purchase helium. The term does not include Federal

agencies, but does include Federal agency contractors.

1.8 *Helium* is the element helium regardless of its physical state.

1.9 *Helium requirement* or *requirement of helium* is all helium, whether in the gaseous or liquid state or in mixtures with other gases, that is required by or delivered to a Federal agency, to accomplish an objective, project, mission, or program of the Federal agency.

1.10 *Major helium requirement* or *major requirement of helium* is a helium requirement of 5,000 scf or more during a calendar month, including the first 5,000 scf per calendar month when the ''helium requirement'' equals or exceeds 5,000 scf per calendar month.

1.11 *Secretary* is the Secretary of the Deparrment of the Interior.

1.12 *Shipping point* is a shipping facility of the Bureau Helium Distribution Contractor from which Bureau of Mines helium is available.

1.13 *Standard cubic foot* (scf) is a 1-cubic-foot volume of Grade-A helium measured at a pressure of 14.7 pounds per square inch absolute and a temperature of 70° Fahrenheit. Volumes of liquid helium shall be expressed in liters or U.S. gallons. One liter of liquid helium is equivalent to 26.63 standard cubic feet of gaseous helium. One U.S. gallon of liquid helium is equivalent to 100.8 standard cubic feet of gaseous helium. One pound of liquid helium is equivalent to 96.67 standard cubic feet of gaseous helium. Appropriate Grade-A gaseous equivalents of volumes of helium mixtures different in any way from Grade-A gaseous helium may be used, and such equivalents must be used when required by the Division of Helium Operations, Bureau of Mines, Amarillo, Texas.

1.14 *Grade-A helium* means the grade of helium produced at the Bureau's helium plants, and it is 99.995 percent pure helium or better, by volume.

Article II—Term of Contract

2.1 This contract shall be effective on the date heretofore stated and shall remain effective for a period of three (3) years thereafter unless sooner terminated as hereinafter provided in section 6.2 or for default.

Article III—Bureau Helium Distribution Contractor

3.1 The Bureau Helium Distribution Contractor (hereafter styled Contractor) shall deliver only Bureau of Mines helium to supply: (1) major helium requirements of a Federal agency without regard as to whether or not Bureau of Mines helium is specified by the agency, (2) any quantity of helium to a Federal agency if procurement documents specify in any manner that Bureau of Mines helium be furnished, (3) any quantity of helium to private helium purchasers if procurement documents specify in any manner the intent that Bureau of Mines helium be furnished, (4) any quantity of helium to another Bureau helium distribution contractor if certification as Bureau of Mines helium is required or furnished.

3.2 Helium delivered for Federal use under the terms of this contract shall conform to the quality, quantity, and delivery requirements agreed to between the Contractor and the purchasing Federal Agency or private helium purchaser.

3.3 Each delivery of helium that requires Bureau of Mines helium in accordance with Sec. 3.1 of this contract shall be made only from an inventory of Bureau of Mines helium on hand except as provided in Sec. 3.4 of this contract.

3.4 Helium is a fungible commodity; therefore, the Contractor may commingle Bureau of Mines helium with helium from other sources. For purposes of Bureau helium accounting records, as much of the Contractor's helium inventory will be considered Bureau of Mines helium as is equal to the volume of: (1) helium purchased from the Bureau of Mines and delivered to the Contractor, plus (2) helium delivered to the Contractor by another Bureau helium distribution contractor and certified as Bureau of Mines helium in accordance with Sec. 3.11 of this contract, less (3) helium deliveries in accordance with Sec. 3.1 of this contract. The Contractor may, except as restricted by Sec. 3.6 of this contract, sell as Bureau of Mines helium volumes of helium from its inventory even though its inventory does not contain, at the time of sale, sufficient helium purchased from the Bureau of Mines or helium received from and certified as Bureau of Mines helium by another Bureau helium distribution contractor to meet the Bureau of Mines helium requirements of the purchaser; however, the Contractor shall report such sales as sales of Bureau of Mines helium and shall, within thirty (30) calendar days following the end of a reporting period or discovery of a negative inventory of Bureau of Mines helium, whichever is sooner, place a firm procurement order with the Bureau of Mines or another Bureau helium distribution contractor for sufficient Bureau of Mines helium to restore its Bureau of Mines helium inventory to a positive value. Failure to order sufficient helium within the thirty (30) day period shall be sufficient grounds to terminate this contract for cause, according to Sec. 3.7.

3.5 The Contractor's opening inventory of Bureau of Mines helium on its initial report to the Bureau shall be any Bureau of Mines helium received and not delivered in accordance with the provisions of this contract within the thirty (30) day period immediately preceding the effective date of this contract, except that, in the event that the Contractor was an Eligible Private Helium Distributor at the time of entering into this

contract, opening inventories under this contract will be determined by the Bureau of Mines based on the Eligible Distributor's reports for the previous reporting periods and examination of Eligible Distributor's helium accounting records by a Bureau representative.

3.6 The inventory balance of Bureau helium at the end of an annual reporting period may be carried forward as the opening inventory for the subsequent period, provided, however, that at no time shall the inventory of Bureau helium exceed the total volume of helium in physical inventory.

3.7 At the end of each annual reporting period, the Contractor shall have a positive or zero balance of Bureau of Mines helium in its inventory. Negative closing balances of Bureau of Mines helium at the end of the annual reporting period, whether reported by the Contractor on its ''Bureau of Mines Helium'' (Addendum C), or revealed through Bureau of Mines examination of the Contractor's Bureau helium accounting records, if not changed to a positive value within thirty (30) days according to Sec. 3.4, shall be sufficient cause for termination of this contract.

3.8 The Contractor shall not add or delete shipping points designated in the original application (Addendum A) except through amendment of this contract. The Contracting Officer, upon receipt of a written request from the Contractor to amend the contract to add or delete shipping points, along with a full explanation of the reason therefor, may send a contract amendment to the Contractor for execution or notify the Contractor of rejection of the request.

3.9 The Contractor shall keep Bureau helium accounting records necessary to show compliance with this contract. Such records shall be kept in a central location and shall be retained for one (1) year following the last day of the applicable annual reporting period. Helium accounting records shall include but are not limited to the following: (1) records of sales of Bureau of Mines helium to each Federal agency and to each private helium purchaser, (2) all pertinent documents supporting sales of Bureau of Mines helium, (3) helium sales contracts between the Contractor and another Federal Agency Contractor who, in the opinion of the Contracting Officer, may reasonably be considered a Federal Agency Contractor, (4) all pertinent documents supporting any contention that a Federal Agency Contractor was not required to use Bureau of Mines helium to meet the requirements of a Federal Agency, or a Federal Agency Contractor whose order intended delivery of Bureau of Mines helium in the opinion of the Contracting Officer, (5) certificates of Resale of Bureau of Mines helium certifying the resale of helium as required by Sec. 3.11 of this contract.

3.10 The Contracting Officer or his duly authorized representative shall have access to and the right to examine, during the Contractor's normal business hours, any pertinent books, documents, records, and physical facilities involving transactions related in any way to this contract.

3.11 Sales of Bureau of Mines helium to another Bureau helium distribution contractor shall be certified on a ''Certificate of Resale of Bureau of Mines Helium'' as illustrated in Addendum B to this contract. The original of the Certificate shall be furnished to the buyer. The Contractor shall submit a fully executed copy of each Certificate issued during a reporting period with its annual report of ''Bureau of Mines Helium.'' One copy of each Certificate issued shall be retained in the Central Bureau helium accounting records of the Contractor.

3.12 Receipts of Bureau of Mines helium from another Bureau helium distribution contractor shall be substantiated by the original ''Certificate of Resale of Bureau of Mines Helium'' executed and issued by the selling Bureau helium distribution contractor at the time of the sale and retained in the buying contractor's Bureau helium accounting records according to Sec. 3.9(5). The buying contractor shall submit a copy of each original Certificate received during a reporting period with its annual report of ''Bureau of Mines Helium,'' (Addendum C). No claimed receipt of Bureau of Mines helium from another Bureau helium distribution contractor will be allowed on an annual report unless fully supported by copies of valid Certificates.

3.13 The Form No. 6–1575–A Rev., ''Bureau of Mines Helium'' attached as Addendum C to this contract, shall be used by the Contractor to report the stocks, receipts, and distribution of Bureau of Mines helium. The required reporting period is January 1 through December 31 of each calendar year. The reports are due at the Bureau of Mines office indicated below on or before the thirtieth (30th) day of January of each year following the applicable preceding reporting period. The completed forms shall be submitted to the Department of the Interior, Bureau of Mines, Division of Helium Operations, 1100 S. Fillmore St., Amarillo, Texas 79101. Copies of the blank form may be obtained from the above address.

Article IV—Bureau of Mines

4.1 The Bureau of Mines will place the Contractor's name, address, and locations of designated shipping points on the Bureau of Mines list of Bureau Helium Distribution Contractors.

4.2 The Bureau of Mines will furnish its list of Bureau Helium Distribution Contractors to known users of Bureau of Mines Helium, and to other parties upon request, for their use in obtaining Bureau of Mines helium.

4.3 The Bureau of Mines authorizes the Contractor to sell and distribute Bureau of Mines helium in accordance with the provision of this contract and to compete in the open market for such sales of Bureau of Mines helium that are otherwise reserved to the Secretary of the Department of the Interior.

4.4 The Bureau of Mines will furnish, upon request by the contractor, information as to which Federal agencies have major helium requirements.

Article V—Conditions

5.1 *Repurchase rights.* The Bureau of Mines shall have the right to repurchase from the original purchaser helium that has been sold by the Bureau and that has not been resold, lost or dissipated, when needed for United States Government use, as provided in Sec. 6(e) of the Helium Act. However, small volumes of Bureau helium purchased by the Contractor from another Bureau helium distribution contractor shall not be subject to repurchase by the Bureau.

5.2 *Liability*

(a) The Bureau of Mines warrants the quality and quantity of helium delivered to the original purchaser only and assumes no further liability, financial or otherwise, in connection with any sale or delivery of helium hereunder, including but not limited to claims relating to: (1) losses on business transactions or commitments between original purchaser and third parties, such as the Contractor, (2) losses on original purchaser's helium containers filled by the Bureau, or (3) losses occasioned by transportation delays.

(b) Contractor shall be liable for any and all actual damages to the Government caused by Contractor, Contractor's representatives, or Contractor's owned or leased equipment.

(c) Contractor is hereby advised that helium requirements of the United States Government shall have priority over non-Government requirements and that such priority requirements of the Government or occasions of Force Majeure may cause delay or deferral of shipment of any helium ordered by Contractor from the Bureau of Mines or another Bureau helium distribution contractor under this contract.

Article VI—General Provisions

6.1 This contract cannot be assigned or otherwise transferred without the express written approval of the Contracting Officer.

6.2 This contract may be terminated at any time by either party by serving not less than sixty (60) days' written notice of termination upon the other party, stating therein the date that such termination shall be effective. In the event of contract termination under the provisions of this Sec. 6.2, a report of receipts and distribution of Bureau of Mines helium, as required by Sec. 3.13 of this contract, shall be submitted for the period from January 1 to the effective date of the termination in the calendar year in which the termination occurs within 15 days after the effective date of the termination.

6.3 *Disputes*

(A) Except as otherwise provided in this contract, any dispute concerning a question of fact arising under this contract which is not disposed of by agreement shall be decided by the Contracting Officer, who shall reduce his decision to writing and mail or otherwise furnish a copy thereof to the Contractor. The decision of the Contracting Officer shall be final and conclusive unless, within 30 days from the date of receipt of such copy, the Contractor mails or otherwise furnishes to the Contracting Officer a written appeal addressed to the Secretary. The decision of the Secretary or his duly authorized representative for the determination of such appeals shall be final and conclusive unless determined by a court of competent jurisdiction to have been fraudulent, or capricious, or arbitrary, or so grossly erroneous as necessarily to imply bad faith, or not supported by substantial evidence. In connection with any appeal proceeding under this clause, the Contractor shall be afforded an opportunity to be heard and to offer evidence in support of its appeal. Pending final decision of a dispute hereunder, the Contractor shall proceed diligently with the performance of the contract and in accordance with the Contracting Officer's decision.

(b) This ''Disputes'' clause does not preclude consideration of law questions in connection with decisions provided for in Sec. 6.3.a above, *Provided,* That nothing in this contract shall be construed as making final the decision of any administrative official, representative, or board on a question of law.

Standard Provisions

The remainder of the contract is comprised of nine standard provisions as follows:

6.4 Officials Not to Benefit
6.5 Covenant Against Contingent Fees
6.6 Utilization of Small Business Concerns
6.7 Utilization of Labor Surplus Area Concerns
6.8 Utilization of Minority Business Enterprises
6.9 Equal Opportunity
6.10 Affirmative Action for Handicapped Workers
6.11 Affirmative Action for Disabled Veterans and Veterans of the Vietnam Era
6.12 Clean Air and Water

In witness whereof, the parties hereto have caused this contract to be fully executed in duplicate by their proper officers the day and year first above written.

United States of America, Department of the Interior, Bureau of Mines.

By _____

Contracting Officer.

Bureau Helium Distribution Contractor.

_____

(Name of Individual or Company)

By _____

(Signature)

Title _____

(The following is to be executed if Contractor is a Corporation.)

I, the undersigned, hereby certify that I am the _____ Secretary of the above-named corporation; that the officer who signed this contract on behalf of such corporation was then acting in the capacity indicated; and that the records of the corporation, of which I have custody, indicate that such officer has the authority to so bind the corporation and that such authority is within the scope of its corporate power, and has not been revoked.

_____

(Signature)

(Affix Corporate Seal)

Addendum A

Form 6—1581-X
Helium Ope. (9-81)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF MINES
WASHINGTON D.C. 20241

O.M.B. No. 1032-0113
Approval Expires 12/31/83

Application to enter into a contract with the United States Department of the Interior, Bureau of Mines, as a Bureau Helium Distribution Contractor

"The Paperwork Reduction Act of 1980 (44 U.S.C. 35) requires us to inform you that: This information is being collected to determine essential applicant data necessary for completion of a contract. This information will be used to determine the legitimacy of applicants as possible helium distribution contractors. The obligation to respond is required to obtain a benefit."

Application is hereby made on this date, _____ , 19___, by _____ whose principal address is _____ to enter into a contract with the United States Department of the Interior, Bureau of Mines, as a "Bureau Helium Distribution Contractor." Upon acceptance of this application and execution of the contract by both parties, the Contractor may sell and distribute Bureau of Mines helium for Federal use and may compete in the open market for such sales that are otherwise reserved, by Statute, to the Secretary of the Department of the Interior.

Applicant submits the following information and attests to its accuracy and completeness, with the understanding that the Bureau of Mines may make further inquiry of Applicant or others. (If additional space is needed to answer any question, additional sheets may be attached. If additional sheets are used, please reference all answers to the applicable question number.)

1. As of the date of this application, applicant is ☐ or is not ☐ distributing helium for Federal use as a Bureau of Mines "Eligible Private Helium Distributor."

2. If the answer to 1. above is negative, applicant has ☐ or has not ☐ previously been an Eligible Private Helium Distributor.

3. Indicate the range of total volume of helium (commercial and/or Bureau of Mines helium) distributed by the Company during the past calendar year:

☐ More than
2,000 Mcf of gaseous helium
☐ Less than

☐ More than
50,000 liters of liquid helium
☐ Less than

4. Indicate the range of total volume of other compressed or liquefied gases distributed by the company during the past calendar year.

☐ More than
5,000 Mcf of compressed gases
☐ Less than

☐ More than
100,000 liters of liquefied gases
☐ Less than

5. List each shipping point, along with the mailing address thereof, that Applicant wishes to designate for distribution of Bureau of Mines helium for Federal use.

OVER

6. Describe Applicant's facilities and equipment to be used in supplying helium requirements of Federal use customers.

a. Plant and container filling

b. Containers

c. Quality control and methods.

d. Does Applicant have rail siding within or adjacent to its facilities?

7. Based on past performance records, estimate delivery time to Federal use customers that Applicant anticipates serving.

_____ % within 24 hours after receipt of order.

_____ % longer than 24 hours after receipt of order.

8. Based on Applicant's present accounting system, describe any problems that would result from the records and reporting requirements of the contract.

9. Present a statement of facts concerning Applicant's financial capability, including the maintenance of an inventory of Bureau of Mines helium to meet anticipated sales for Federal use.

The Government reserves the right to reject any application and not award a contract.

Applicant hereby acknowledges that it has reviewed the attached contract documents and agrees to the terms thereof, and further agrees that this application, if approved, will be attached to and form a part of the resulting contract.

_____
Name of Applicant

_____
Name and Title of Signer
(Print or Type)

_____
Signature

_____
Date

Addendum B

Form 6-1580-A
Helium Oper. (9-81)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF MINES
WASHINGTON D.C. 20241

O.M.B. No. 1032-0113
Approval Expires 12/31/83

INDIVIDUAL COMPANY DATA—PROPRIETARY

The data furnished in this report will be treated in confidence by the Department of the Interior, except that they may be disclosed to Federal defense agencies, or to the Congress upon official request for appropriate purposes.

CERTIFICATE
OF
RESALE
OF
BUREAU OF MINES HELIUM

"The Paperwork Reduction Act of 1980 (44 U.S.C. 35) requires us to inform you that: This information is being collected to determine distributor accountablity and certification of compliance with the 30 CFR 602. This information will be used to account for helium transfer between distributors. The obligation to respond is required to obtain a benefit."

I certify that on this _____ day of _____, 198___,

_____ standard cubic feet of Bureau of Mines helium (convert liquid helium to its gaseous helium equivalent) was sold from

(Company)_____,

to

(Company)_____.

Name _____

Title _____

Company _____

Address _____

_____

Signature _____

Form 6-1575-A
Helium Oper. 9-81)

Addendum C
UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF MINES
WASHINGTON D.C. 20241

O.M.B. No. 1032-0113
Approval Expires 12/31/83

INDIVIDUAL COMPANY DATA—PROPRIETARY

The data furnished in this report will be treated in confidence by the Department of the Interior, except that they may be disclosed to Federal defense agencies, or to the Congress upon official request for appropriate purposes.

BUREAU OF MINES HELIUM:
Stocks, Receipts, and Distribution

Year 19_____

To: Bureau of Mines, Helium Operations,
Department of the Interior
1100 South Fillmore Street
Amarillo, Texas 79101

"The Paperwork Reduction Act of 1980 (44 U.S.C. 35) requires us to inform you that: This information is being collected for the purpose of distributor accountability and certification of compliance with the Regulation. This information will be used to report annual sales, transfers, and purchases of Bureau helium as certification of compliance with 30 CFR 602. The obligation to respond is required to obtain a benefit."

This report is required by contract. The Bureau of Mines may withhold deliveries under a contract or terminate a contract with a private helium distributor for failue to comply with the reporting provisions specified by contract.

SECTION 1. COMPANY IDENTIFICATION.

Each distributor should prepare this report. Indicate opening stocks, receipts, distribution and closing balance, in Section 2 for indicated annual period.

1. Your company name _____
2. Address _____

SECTION 2. STOCKS, RECEIPTS, AND DISTRIBUTION FOR INDICATED ANNUAL PERIOD.

Because sales of Bureau of Mines helium to civilian consumers are not required to be reported, the closing balance of Bureau of Mines helium may exceed the total closing helium inventory. However, it is not possible for the opening inventory of Bureau of Mines helium to exceed the total helium inventory at the beginning of a reporting period. Purchases and transfers from sources other than the Bureau of Mines must be supported by copies of certificates from suppliers. Copies of this certificate are enclosed with this mailing.

Item (1)		Liquid and Gaseous Helium Standard Cubic Feet[1] (2)
1. Opening Inventory:		
(a) Carryover closing balance from previous period or total helium inventory, whichever is smaller		
2. Receipts:		
(a) By purchase from Bureau of Mines		
(b) By purchase from another distributor		
(c) Total receipts (equals 2 (a) plus 2 (b))		
3. Total Available for Distribution this Period (equals 1 (a) plus 2 (b))		
4. Distribution:		
(a) By sale to Federal agencies		
(b) By certified sale to another distributor		
(c) Total distribution (equals 4 (a) plus 4 (b))		
5. Closing Balance (equals 3 minus 4 (c))		
6. CLOSING INVENTORY (actual helium on hand at end of period)		

1/ Liquid helium shall be reported in gaseous helium equivalent. One liter of liquid helium is equivalent to 26.63 standard cubic feet and 1 gallon of liquid helium is equivalent to 100.82 standard cubic feet.

CERTIFICATION—I certify that the forgoing report is true, correct, and complete to the best of my knowledge and belief.

Name _____ Title _____

Signature _____ Date _____

Name of person to be contacted regarding this report			Tel. area code	No.	Ext.
Address	No.	Street	City	State	Zip

SUBCHAPTERS B—L [RESERVED]
SUBCHAPTER M—RULES AND REGULATIONS FOR THE ADMINISTRATION OF GRANTS

PART 652—MINING AND MINERAL RESOURCES RESEARCH INSTITUTE PROGRAM

Sec.
652.1 Scope.
652.2 Objectives.
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652.6 Eligibility.
652.7 Responsibilities of institutions designated as mineral institutes.
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652.13 Reports.
652.14 Information collection.
652.15 Advisory committee.
652.16 Site visits.
652.17 Grant modifications.
652.18 Grant reduction and termination.

AUTHORITY: 30 U.S.C. 1221–1230; Pub. L. 98–409; Pub. L. 100–483.

SOURCE: 54 FR 38378, Sept. 18, 1989, unless otherwise noted.

§ 652.1 Scope.

This part sets forth policies and procedures for the assistance of institutions of higher learning that have been designated as State Mining and Mineral Resources Research Institutes and for the support of mining and mineral resources research at these institutions through specialized generic mineral technology research centers.

§ 652.2 Objectives.

The objectives of the assistance provided by the Mining and Mineral Resources Research Institute program are:

(a) To support research and training in mining and mineral resources problems related to the mission of the Department of the Interior;

(b) To improve the advanced training of mineral scientists and engineers through grants which encourage State and industry support of mineral education;

(c) To support, and encourage support of, research centers of generic expertise in mineral technology;

(d) To assist the States in carrying on the work of competent and qualified mining and mineral resources research institutes; and

(e) To provide support for graduate and postdoctoral students in mining and mineral resources disciplines including mining engineering, extractive metallurgy, geology, reclamation, engineering, economics, chemistry, physics, biology, ecology, and others.

§ 652.3 Authority.

The authority for this program is the Mining and Mineral Resources Research Program Act of 1984 and the Mining and Mineral Resources Research Institute Amendments of 1988.

(a) 30 U.S.C. 1221 authorizes the Secretary to make grants to assist States on a matching basis in carrying on the work of competent and qualified mining and mineral resources research institutes.

(b) 30 U.S.C. 1222 authorizes the Secretary to make grants to the institutes for specific research and demonstration projects, and for research into any aspects of mining and mineral resources problems related to the mission of the Department of the Interior deemed desirable and not otherwise under study.

(c) 30 U.S.C. 1229 authorizes the Secretary to appoint an Advisory Committee on Mining and Mineral Resources Research jointly chaired by the Assistant Secretary of the Interior responsible for minerals and mining and a committee member elected by the Committee from among those members who are not Federal employees.

§ 652.4 Administration.

Responsibility for administration of the Mining and Mineral Resources Research Institute Program is assigned to the Director of the Bureau of Mines

and subject to the supervisory authority of the Assistant Secretary to whom he/she reports.

§652.5 Definitions.

As used in this part, the term—

Act means the State Mining and Mineral Resources Research Program Act of 1984 and subsequent amendments.

Advisory Committee means the Advisory Committee on Mining and Mineral Resources Research appointed by the Secretary pursuant to 30 U.S.C. 1229.

Allotment grant means funds made available to a mineral institute for the support of mineral-related research and education on a matching (formula) basis in a particular fiscal year pursuant to 30 U.S.C. 1221 and under the regulations contained herein.

Bureau means the Bureau of Mines.

Call for proposals means a letter from the Director to eligible mineral institutes and generic mineral technology centers requesting proposals for allotment or research grants, and specifying the format and date for receipt at the Office and other conditions. Separate Calls for proposals are issued annually for allotment and research grants. Applications for funds may be submitted only in response to a Call for Proposals.

Director means Director of the Bureau of Mines.

Generic mineral technology center means a cooperative mineral resources research effort in a specific area of broad applicability across the minerals industry headquartered in one institute with participation by one or more affiliate mineral institutes as authorized under 30 U.S.C. 1222.

Grant agreement means the legal document that sets forth the rules for the administration of the grant, including the responsibilities and privileges of the recipient, the amount of the award, reports required, and applicable rules and regulations.

Mineral institute means a competent and qualified mining and mineral resources research institute, department, or component of a college or university that conducts mineral resources research, which is determined to be eligible in accordance with the provisions of the Act, and which is designated by the Secretary as a State Mining and Mineral Resources Institute.

Mineral resources research means research, investigations, demonstrations, and experiments of a basic or practical nature relating to mineral exploration, extraction, processing, development, production, mining and technology, supply and demand, conservation and best use of available supplies, and the mineral-related aspects of other disciplines; and the training of mineral engineers and scientists through such activity; and the planning and coordination of such cooperative activity with other mineral institutes and those other agencies and individuals as may contribute to the solution of mining and mineral resources problems.

Office means Office of Mineral Institutes.

Secretary means the Secretary of the Interior or his authorized representative.

§652.6 Eligibility.

Only institutions of higher learning (post-secondary institutions having graduate research programs) designated by the Secretary, after consultation with, and upon the advice of the Advisory Committee, as a State Mining and Mineral Resources Research Institute are eligible to receive funds under this program. Only one institution may be designated per State. To qualify as a mineral institute, institutions must meet all the following criteria as determined by the Advisory Committee:

(a) Be either a public college or university or, in a State not having an eligible public college or university, a private college or university in that State.

(b) Be recommended by the Governor of the State, as eligible, in the absence of contrary act by the legislature of the State.

(c) Have in existence a substantial program of graduate instruction and research in mining or mineral extraction or closely related fields which has a demonstrated history of achievement.

(d) Evidence institutional commitment to the purposes of the Act.

(e) Exhibit significant industrial cooperation in activities within the scope of the Act.

(f) Have in existence an engineering program in mining or minerals extraction that is accredited by the Accreditation Board for Engineering and Technology, or show evidence of equivalent institutional capability.

(g) Employ at least six full-time permanent faculty members in the department or component of the institution conducting instruction and research in mining and mineral extraction.

(h) Meet such other criteria as the Advisory Committee shall deem necessary or desirable.

§ 652.7 Responsibilities of institutions designated as mineral institutes.

(a) Each institution designated as mineral institute has the duty of planning and conducting mineral resources research. To carry out its responsibility, it shall appoint a mineral institute director from its faculty or staff, who is professionally qualified in minerals research and education.

(b) Mineral institute directors shall be responsible for preparation of allotment grant proposals; for the technical administration of allotment grant agreements; for periodic reporting to the Bureau of Mines; for the preparation and transmission to the Bureau of Mines of an annual institute status report; for providing such coordination as may be necessary between various departments, units, and individuals at that institution to achieve a focused minerals program of value to the mineral institute's State and region; for the coordination between and among the minerals programs of the several mineral institutes; for responding to requests for information regarding the minerals program at that institution from the Bureau of Mines, the Advisory Committee, and the public; and for the selection and transmission of the best research proposals from that institution for inclusion in the generic mineral technology center program.

§ 652.8 Applications for allotment grants.

Applications for annual allotment grants shall be submitted in response to an annual call for proposals issued by the Bureau of Mines to mineral institutes. To receive a new allotment grant, a mineral institute must have submitted all reports due and shall not have been found by the Secretary to have improperly diminished, lost, or misapplied funds previously received. Such funds shall be replaced by the State concerned and until so replaced no subsequent grant shall be allotted or paid to the institute of that State. Each allotment grant application shall be responsive to 30 U.S.C. 1221(b) and as a minimum shall consist of the following elements in duplicate:

(a) A completed Standard Form 424.

(b) A plan to provide for the training of individuals as mineral engineers and scientists under a curriculum appropriate to the field of mineral resources and mineral engineering and related fields.

(c) A budget to support that plan.

(d) Assurance that Federal funds will supplement and, to the extent practicable, increase the level of funds that would otherwise have been available for the purposes of the Act, and in no case supplant such funds.

(e) Such other information as is requested in the Call for Proposals.

The Secretary shall deny or reduce funds to mineral institutes where proposals or portions thereof are not complementary to the mission of the Department or the goals of this program.

§ 652.9 Generic mineral technology centers.

All research supported under this program, except for that funded through allotment grants, is funded through established generic mineral technology centers (generic centers). Each generic center provides a focus for mineral research in a specific area of broad applicability across the minerals industry. Each generic center has the following characteristics:

(a) It is headquartered in one mineral institute with participation by one or more affiliate institutions.

(b) A generic center director supervises the operation of the center including the coordination of related projects; makes arrangements for an annual seminar; provides for operation of a reference center; makes recommendations to the Bureau of Mines

on budget revisions, equipment purchases, and other grant modifications; and provides technical leadership for the center.

(c) A reference center serves as a centralized repository of literature concerning the generic research area and also is a repository of all periodic and final reports, dissertations, and contributions to the technical literature resulting from generic center research.

(d) An annual seminar provides opportunity for students and principal investigators to exchange ideas and present their latest research in the generic area.

(e) A Research Council, consisting of experts in the generic research area from industry, government and, where possible, academia, attends the annual seminars, receives periodic reports, evaluates research proposals, and provides recommendations to the Bureau of Mines on the program of the center.

(f) New proposals for research, submitted through generic center and mineral institute directors, are evaluated on a competitive basis, in writing, and through Council discussion.

§652.10 Application for research grants.

Proposals may be submitted to the Bureau of Mines in any of the generic mineral technology areas through mineral institute and generic mineral technology center directors in response to an annual call for proposals which describes the format of the proposals. Proposals shall address the requirements of 30 U.S.C. 1222 (b) through (d) as detailed in the call for proposals. No portion of any research grant shall be applied to the acquisition by purchase or lease of any land or interests therein or the rental, purchase, construction, preservation or repair of any building.

§652.11 Transfers of research and allotment grant funds.

Under 30 U.S.C. 1223(b), mineral institutes are authorized to conduct cooperative programs with other mineral institutes and with such other agencies and individuals as may contribute to the solution of the mining and mineral resource problems involved. Mineral institutes may utilize their funds to pay for projects at other institutions under the following limitations:

(a) The mineral institute director (for allotment grants) or the generic mineral technology center director (for research grants) for the institution awarded the funds by the Bureau, or the designated representative of the above, shall administer, conduct and supervise all funded programs.

(b) All proposals to fund noninstitute activities shall be specifically set forth in the grant proposal applications required under §652.8 and §652.10 and must be explicitly approved by the Bureau of Mines.

(c) All subgrants and subcontracts, service agreements, and interdivisional work authorizations shall be subject to the same terms and conditions as the grant.

(d) Copies of all agreements for funding of programs conducted by noninstitute organizations, universities, or individuals shall be made available to the Bureau of Mines upon request.

§652.12 Governing provisions for grants.

Performance under all grants shall be in accord with the terms and conditions set forth in OMB Circulars A–110 (General Administration), A–21 (Cost Principles), A–88 (Indirect Cost Rates and Audit), and all other applicable laws and regulations. Copies of the OMB circulars are available from Publications Services, 725 17th Street NW., Room 2200, Washington, DC 20503. All uses, products, processes, patents, and other developments under this program, with such exceptions as the Secretary may make in the public interest, are to be made promptly available to the public. Patentable inventions shall be governed by the provisions of Pub. L. 96–517.

[54 FR 38378, Sept. 18, 1989, as amended at 55 FR 35300, Aug. 29, 1990]

§652.13 Reports.

The following reports are required from program participants:

(a) *Annual Institute Status Report (30 U.S.C. 1223(a)(3)).* On or before September 1 of each year, the mineral institute director for each institute shall submit to the Office a written report on work accomplished; the status of

projects underway; a listing of scholarship and fellowship holders supported under this program, their departmental affiliation, citizenship, amount of award, and thesis title, if selected; and a statement of disbursements of funds received under this program. This report shall cover all activities under both the allotment grant and research grant program.

(b) *Periodic Technical Reports.* Each mineral institute and generic center director shall make brief periodic written reports as specified in the grant document to the Office describing progress made on each active project. Generic center directors shall also send their periodic reports to members of the applicable Research Councils.

(c) *Periodic Financial Reports.* Each mineral institute and generic center shall submit completed Standard Form–269 reports concurrent with the periodic technical progress reports.

(d) *Annual Property Report.* Each mineral institute and generic center shall submit by November 15 a completed Bureau of Mines Form 6–359 on nonexpendable property.

(e) *Final Reports.* The annual institute status report will serve as the final report for allotment grants. A final report is required for each approved generic center research project. Principal investigators are encouraged to publish in the technical literature any information developed in the course of carrying out a research project. A published journal article may be substituted for a final report, provided the Grantee delivers five copies of the reprint to the Office. If the findings of a research project are not published, five copies of a final report shall be furnished. An unpublished final report should be prepared in accordance with ANSI 239.18–1974, ''American National Standard Guidelines for Format and Production of Scientific and Technical Reports.''

(1) *Credits.* Every final research report or publication in the technical literature shall contain one of the following statements or the equivalent:

This research has been supported by the Department of the Interior's Mineral Institute Program administered by the Bureau of Mines under allotment grant number _____.

This research has been supported by the Department of the Interior's Mineral Institute Program administered by the Bureau of Mines through the Generic Mineral Technology Center for _____ under research grant number _____.

§ 652.14 Information collection.

The information collection requirements contained in this section have been approved by the Office of Management and Budget under 44 U.S.C. 3501 *et seq.* and assigned clearance number 1032–0116. The information is being collected to evaluate the effectiveness of the programs and responses are required to obtain a benefit in accordance with 30 U.S.C. 1221–1230. Public reporting burden for this information, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information is as follows:

Performance Report.....16 hours
Report of Funded Scholarship and Fellowships.....2 hours
Summary Report of Inventions and Subgrants .....1 hour
Grantee Inventory of Property Purchased from Grant Funds .....2 hours
Budget Information Report.....8 hours.

Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Office of Statistical Standards, Bureau of Mines, Washington, DC 20241; and to the Office of Management and Budget, Paperwork Reduction Project (OMB No. 1032–0116), Washington, DC 20503.

§ 652.15 Advisory committee.

An Advisory Committee on Mining and Mineral Resources Research, appointed by the Secretary under 30 U.S.C. 1229, shall consult with and make recommendations to the Secretary on the operation of and the making of grants under this program and it shall determine the eligibility of a college or university to participate as a Mining and Mineral Resources Research Institute under the Act and make such recommendation to the Secretary.

§ 652.16 Site visits.

In relation to the substantive scientific and administrative operations of grantees, the Bureau of Mines or the Advisory Committee may perform inspections of activities authorized and financed pursuant to these regulations. Such inspections may cover acceptability of progress, consistency with approved plans, and institute eligibility.

§ 652.17 Grant modifications.

(a) The mineral institute and generic center directors are responsible for promptly notifying the Office of events which may require modification of grant agreements, such as:

(1) Rebudgetings,

(2) No-cost time extensions, or

(3) Changes in scope.

(b) Permission of the Office is also required for the following actions under a grant:

(1) Equipment purchase of $1000 or more,

(2) Property transfer, or

(3) Foreign travel.

§ 652.18 Grant reduction and termination.

If a mineral institute or generic mineral technology center does not follow the provisions and terms of a grant or does not fully implement a grant program, the Director may reduce the size of or may suspend or terminate a grant.

[54 FR 38378, Sept. 18, 1989; 55 FR 35301, Aug. 29, 1990]

PARTS 653—699 [RESERVED]

FINDING AIDS

A list of CFR titles, subtitles, chapters, subchapters and parts and an alphabetical list of agencies publishing in the CFR are included in the CFR Index and Finding Aids volume to the Code of Federal Regulations which is published separately and revised annually.

Material Approved for Incorporation by Reference
Table of CFR Titles and Chapters
Alphabetical List of Agencies Appearing in the CFR
Redesignation Table
List of CFR Sections Affected

Material Approved for Incorporation by Reference

(Revised as of July 1, 1997)

The Director of the Federal Register has approved under 5 U.S.C. 552(a) and 1 CFR Part 51 the incorporation by reference of the following publications. This list contains only those incorporations by reference effective as of the revision date of this volume. Incorporations by reference found within a regulation are effective upon the effective date of that regulation. For more information on incorporation by reference, see the preliminary pages of this volume.

30 CFR CHAPTER II (PARTS 200–699)
MINERALS MANAGEMENT SERVICE, DEPARTMENT OF THE INTERIOR

	30 CFR
American Concrete Institute P.O. Box 19150, Detroit, Michigan 48219	
ACI Standard 318–83, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R–83).	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), and (e)(2)(i)
ACI Standard 318-95, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R-95).	250.1(a); 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), and (c)(3)
American Institute of Steel Construction, Inc. P.O. Box 4588, Chicago, Illinois 60680.	
AISC Standard S326, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, 1978 Edition.	250.137(b)(1)(ii), (c)(4)(ii), and (c)(4)(vii)
AISC Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, June 1, 1989, with Commentary.	250.1(b); 250.137(b)(1)(ii), (c)(4)(ii) and (c)(4)(vii)
American National Standards Institute Sales Department, 1430 Broadway, New York, New York 10018	
American Society of Mechanical Engineers United Engineering Center, 345 East 47th Street, New York, New York 10017.	

30 CFR CHAPTER II (PARTS 200–699)—Continued

MINERALS MANAGEMENT SERVICE, DEPARTMENT OF THE INTERIOR—Continued

	30 CFR
ANSI/ASME Boiler and Pressure Vessel Code, Section I, Power Boilers, including Appendices, 1983 Edition, with Summer and Winter 1983 and 1984 and Summer 1985 Addendas.	250.1; 250.123(b)(1), and (b)(1)(i); 250.292(b)(1) and (b)(1)(i)
ANSI/ASME Boiler and Pressure Vessel Code, Section I, Power Boilers including Appendices, 1995 Edition.	250.1(c); 250.123(b)(1) and (b)(1)(i); 250.292(b)(1) and (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, 1983 Edition, with Summer and Winter 1983 and 1984 and Summer 1985 Addendas.	250.1; 250.123(b)(1), and (b)(1)(i); 250.292(b)(1) and (b)(1)(i)
ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Heating Boilers, including Nonmandatory Appendixes A, B, C, F, H, I, and J and the Guide to Manufacturers Data Report Forms, 1995 Edition.	251.1(c); 250.123(b)(1) and (b)(1)(i); 250.292(b)(1) and (b)(1)(i)
ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Divisions 1 and 2 including Nonmandatory Appendices, 1983 Edition, with Summer and Winter 1983 and 1984 and Summer 1985 Addendas.	250.1; 250.123(b)(1), and (b)(1)(i); 250.292(b)(1) and (b)(1)(i)
ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Divisions 1 and 2, including Nonmandatory Appendices, 1995 Edition.	250.1(c); 250.123(b)(1) and (b)(1)(i); 250.292(b)(1) and (b)(1)(i)
ANSI/ASME B 16.5–1981, Pipe Flanges and Flanged Fittings	250.1; 250.152(b)(2)
ANSI/ASME B 16.5–1988, (including Errata) and B 16.5a–1992 Addenda, Pipe Flanges and Flanged Fittings.	250.1(c); 250.152(b)(2)
ANSI/ASME B 31.8–1986, Gas Transmission and Distribution Piping Systems.	250.1; 250.152(a)
ANSI/ASME B 31.8–1995, Gas Transmission and Distribution Piping Systems.	250.1(c); 250.152(a)
ASME/ANSI SPPE–1–1988, and SPPE–1a–1988, SPPE–1b–1989, SPPE–1c–1989, and SPPE–1d–1990 (addenda), Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations.	250.1; 250.126(c)(2), (e)(1), and (3)
ANSI Z88.2–1980, Practices for Respiratory Protection	250.1; 250.67(h)(2)(iv), and (h)(6)(i)
ANSI Z88.2–1992, American National Standard for Respiratory Protection.	250.67(g)(4)(iv) and (j)(13)(ii)
The American Petroleum Institute 1220 L Street, NW., Washington, D.C. 20005.	
API Spec Q1, Specification for Quality Programs, Third Edition, June 1990, API Stock No. 811–00001.	250.1; 250–126(c)(3)
API RP 2A, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms, Eighteenth Edition, September 1, 1989, API Stock No. 811–00200.	250.1; 250.130(g); 250.142(a)
API RP 2A, Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms Working Stress Design, Nineteenth Edition, August 1, 1991.	250.1(d); 250.130(g); 250.142(a)

Material Approved for Incorporation by Reference

30 CFR CHAPTER II (PARTS 200–699)—Continued

MINERALS MANAGEMENT SERVICE, DEPARTMENT OF THE INTERIOR—Continued

	30 CFR
API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Second Edition, June 1984.	250.1; 250.51(g); 250.260(g)
API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Third Edition, June 1, 1995.	250.1(d); 250.20(c); 250.260(g)
API RP T–2, Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices, Revised October 1975.	250.1; 250.210(a); 250.212(a), and (c)
API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, Fifteenth Edition, April 1, 1986, with Supplement 1, December 1986, API Stock No. 811–03100.	250.1; 250.152(b)(1), and (b)(2)
API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, Seventeenth Edition, February 1, 1996.	250.1(d); 250.126(c)(3), (e)(2) and (e)(3); 250.152(b)(1) and (b)(2)
API Spec 6A V1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996.	250.1(d); 250.126(c)(3)
API Spec 6D, Specification for Pipeline Valves, End Closures, Connectors and Swivels, Eighteenth Edition, January 1982 with Supplement 3, July 1985, API Stock No. 811–03200.	250.1; 250.152(b)(1)
API Spec 6D, Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves), Twenty-first Edition, March 31, 1994.	250.1(d); 250.152(b)(1)
API Spec 14A, Specification for Subsurface Safety Valve Equipment, Seventh Edition, January 1988 with Supplement 1, August 1989, API Stock No. 811–07150.	250.1; 250.126(c)(3), (e)(2), and (3)
API Spec 14A, Specification for Subsurface Safety Valve Equipment, Ninth Edition, July 1, 1994.	250.1(d); 250.126(c)(3), (e)(2) and (e)(3)
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Redesignation Table

At 53 FR 10688, Apr. 1, 1988, 30 CFR part 250 and subpart N of part 256 were restructured and consolidated into revised 30 CFR part 250. For the convenience of the user, the following table shows the relationship of the old CFR section numbers and multitier rules to the new part 250 sections.

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250.11	OCS Order No. 4.
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250.51(d)	OCS Order No. 2, paragraph 2.3.
250.51(e)	250.39; 250.40; OCS Order No. 2, paragraph 4.
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250.51(g)	OCS Order No. 5, paragraph 7.
250.51(h)	OCS Order No. 5, paragraph 5.3.
250.51(i)	OCS Order No. 5, paragraph 5.3.
250.52	OCS Order No. 2, Alaska OCS Region, paragraph 2.1.6, OCS Order No. 5, paragraph 5.4.
250.53	OCS Order No. 2, Alaska OCS Region, paragraphs 12 (a), (b), (e), and (f); OCS Order No. 5, paragraph 5.1.10.
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250.152(a)	New Provision.
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250.152(d)	New Provision.
250.152(f)	New Provision.
250.153	OCS Order No. 9, paragraph 1.C.
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250.154(a)	New Provision.
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250.157(b)	New Provision.
250.158	256.95; OCS Order No. 9, paragraph 1.E.
250.158(a)	New Provision.
250.158(c)	New Provision.
250.158(d)	New Provision.
250.150(f)	New Provision.
250.158(g)	New Provision.
250.158(h)	New Provision.
250.159	256.83; 256.89 [1]; 256.101.
250.160	256.92; 256.94; 256.100.
250.160(d)	New Provision.
250.161	256.85; 256.92; 256.94.
250.162	256.95.
250.163	256.97.
250.164	256.98.
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250.170	OCS Order No. 11, paragraph 1.
250.171	OCS Order No. 11, paragraphs 2 and 14.

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250.171(a)	New Provision.
250.171(c)	New Provision.
250.172	250.16; OCS Order No. 11, paragraphs 3 and 4.
250.172(a)(1)	New Provision.
250.172(a)(3)	New Provision.
250.172(a)(5)	New Provision.
250.172(a)(7)	New Provision.
250.172(a)(8)	New Provision.
250.172(b)(3)	New Provision.
250.172(b)(4)	New Provision.
250.172(b)(5)	New Provision.
250.172(c)	New Provision.
250.173	250.39; OCS Order No. 11, paragraphs 5, 6, 7, and 8.
250.174	OCS Order No. 11, paragraph 9.
250.174(a)	New Provision.
250.175	250.55; OCS Order No. 11, paragraph 10; NTL 75–9 (5/13/75).
250.175(a)(2)(i)	New Provision.
250.175(a)(2)(ii)	New Provision.
250.175(c)	New Provision.
250.176	250.68; OCS Order No.11, paragraph 12.
250.177	OCS Order No. 11, paragraph 15.
250.177(b)	New Provision.
250.177(c)	New Provision.
SUBPART L—PRODUCTION MEASUREMENT, COMMINGLING, AND SECURITY	
250.180	250.60; OCS Order No. 13, paragraphs 2, 3, and 4.
250.181	250.61; OCS Order No. 13, paragraph 5.
250.182	250.68; OCS Order No. 13, paragraph 6 [1].

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250.183	New Provision.
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250.190	250.50; 10 CFR 390.014(d).
250.191	OCS Order No. 11, paragraph 16.
250.192	250.51–1.
250.193	250.51–2.
250.194	Model Unit Agreement.
SUBPART N—REMEDIES AND PENALTIES	
250.200	250.80–1.
250.200(a)(2)	New Provision.
250.201	250.80–1.
250.202	250.80–1.
250.203	250.80–1.
250.204	250.80–1.
250.205	250.80–1.
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SUBPART O—TRAINING	
250.210	250.42.
250.211	250.42.
250.212	250.42.
SUBPART P—SULPHUR OPERATIONS	
250.250	New Provision.

[1] No substantive change.
[2] Codification of existing policy.

Note: The following old sections were deleted as unnecessary and redundant with no substantive change intended: 250.1, 250.4, 250.5, 250.82, and 250.96.

List of CFR Sections Affected

All changes in this volume of the Code of Federal Regulations which were made by documents published in the FEDERAL REGISTER since January 1, 1986, are enumerated in the following list. Entries indicate the nature of the changes effected. Page numbers refer to FEDERAL REGISTER pages. The user should consult the entries for chapters and parts as well as sections for revisions.

For the period before January 1, 1986, see the ''List of Sections Affected, 1949–1963, 1964–1972, 1973–1985'' published in seven separate volumes.

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210 Authority citation revised 15766, 45882
210.10 Table amended 15766
210.53 Redesignated as 210.54; new 210.53 added 45882
210.54 Redesignated from 210.53 45882
210.200—210.203 (Subpart E) Heading revised; sections added 15766
210.204 Added 45883
210 (Subpart F) Heading removed; new Subpart F redesignated from 210.300—210.301 (Subpart G) 15766
210.300—210.301 (Subpart G) Redesignated as Subpart F; new Subpart G heading redesignated from Subpart H heading 15766
210 (Subpart H) Heading redesignated as Subpart G heading 15766
212 Authority citation revised 15766
212.200 (Subpart E) Heading revised 15767
212.200 (a) revised; (b)(1) amended 15767
212 (Subpart F) Heading removed; new Subpart F heading redesignated from Subpart G heading 15767

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212 (Subpart G) Heading redesignated as Subpart F heading; new Subpart G heading redesignated from Subpart H heading 15767
212 (Subpart H) Heading redesignated as Subpart G heading 15767
216 Added 8175
Authority citation revised 45883
216.15 Added 45883
218 Authority citation revised 15767, 19063
218.40 Redesignated from 218.56; (c) amended and (e) redesignated as (d) 15767
218.56 Redesignated as 218.40 and (c) amended and (e) redesignated as (d); new 218.56 redesignated from 218.57 15767
218.57 Redesignated as 218.56 15767
218.154 (a) and (b) revised 19063
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218 (Subpart F) Heading removed; new Subpart F redesignated from 218.300—218.301 (Subpart G) 15767
218.300—218.301 (Subpart G) Redesignated as Subpart F; new Subpart G heading redesignated from Subpart H heading 15767

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256.22 Revised 6107
256.23—256.25 (Subpart D) Heading revised; eff. 7–14–86 21345
256.23 (b) revised; eff. 7–14–86 21345
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256.29 (c) amended 37178

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206 Authority citation revised 3798
206.100 Revised 3798
208 Revised 41913
208.2 Corrected 45528
209 Removed 41918
216 Authority citation revised 27546
216.40 (a) and (b) revised; (g) added 27546
218 Authority citation revised 5458
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218.40 (a) and (b) revised; (e) added 27546
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218.51 Revised; eff. 7–27–87 23814
218.57 Added; eff. 7–31–87 24451
218.100 (a) revised; (c) added; eff. 7–27–87 23815
218.150 (a) revised; eff. 7–27–87 23815
218.152 Revised 5458
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218.155 (a) revised; (d) removed; (e) and (f) redesignated as (d) and (e); eff. 7–27–87 23815
218.156 Added; eff. 7–27–87 23815
218.200 Redesignated as 218.202; new 218.200 added; eff. 7–27–87 23815
218.201 Added; eff. 7–27–87 23815
218.202 Redesignated from 218.200; eff. 7–27–87 23815
218.300 Revised; eff. 7–27–87 23815
218.301 Redesignated as 218.302; new 218.301 added; eff. 7–27–87 23815
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202.101 Removed; new 202.101 added 1217
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202 (Subpart H) Heading revised 1217
202 (Subpart I) Heading revised 1217
203 Authority citation revised 1218
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203 (Subpart C) Heading revised 1218
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203.250 (Subpart F) Heading revised 1218
203.250 Redesignated from 203.200 1218
203 (Subpart G) Heading revised 1218
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206.159 Information collection requirements 4012
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206 (Subpart E) Heading revised 1218
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210 (Subpart F) Heading revised 1226
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241.50—241.53 (Subpart B) Heading revised 1226
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241 (Subpart D) Heading revised 1226
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251.0 (e) amended and (f) added 24688
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251.14–1 (d) (1) and (2) and (e) revised; (c)(3) and (d)(3) removed 4392
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206 Authority citation revised 1522
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250.105 (c)(1) amended 50616
250.106 (a) and (b)(2) amended 50617
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250.121 (d) introductory text and (2) amended 50617
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250.154 (b) (2) and (3) amended 50617
250.159 (a)(1) amended 50617
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250.180 (f)(1) amended 50617
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290 Authority citation revised 52797
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206.251 Amended 35433
206.257 (b)(5) removed; (b)(6) redesignated as (b)(5); (b)(1), (5), (c)(3) and (g) revised 35433
218 Authority citation revised 37230
218.50—218.57 (Subpart B) Authority citation removed 37230
218.54 Heading and (b) revised 37230
218.55 (c) revised 37230
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250.1 Introductory text, (c)(5) and (d) introductory text revised; (d)(6) and (11) removed; (d)(1) through (5), (7), (8) through (10), and (12) through (46) redesignated as (d)(2) through (6), (9), (11) through (13), and (15) through (49); new (d)(1), (7), (8), (10), and (14) added 10617
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208.7 (h) amended 64901
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208.13 Revised 64902
210 Authority citation revised 64902
210.10 (a) table, (b)(3) through (6), (c)(1), (2), (8), (9), (12), (13), (19) and (d) amended; (b)(1) revised; (c)(6), (11), (15) and (17) removed; (c)(7) through (10), (12), (13), (14), (16) and (18) through (23) redesignated as (c)(6) through (19); new (c)(20) added; OMB number 64902
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216 Authority citation revised 45254, 64903
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216.6 Amended 45254
216.15 (a) and (b) amended 64903
216.16 (a) and (b) amended 64903
216.20 Revised 45254
216.40 (c) amended 64903
216.50 (a) removed; (b) through (e) redesignated as (a) through (d); new (a) revised; new (d)(3) amended 45254
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216.51 Revised 45254
216.52 Removed; new 216.52 redesignated from 216.53 64903

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216.53 Redesignated as 216.52; new 216.53 redesignated from 216.54 64903
216.54 Revised 45255
Redesignated as 216.53; new 216.54 redesignated from 216.55 64903
216.55 Revised 45255
Redesignated as 216.54; new 216.55 redesignated from 216.56 64903
216.56 Revised 45255
Redesignated as 216.55; new 216.56 redesignated from 216.58 64903
216.57 Removed; new 216.57 added 64903
216.58 Revised 45255
Redesignated as 216.56 64903
216.61 Removed 64903
218 Authority citation revised 45438, 64903
218.41 Added 45438
218.51 (a)(1) corrected; CFR correction 8907
(f)(2) amended 64903
219.102 Amended 64903
220.003 (b) amended 64903
228.10 (b) amended 64903
229 Authority citation revised 64903
229.123 (b)(2) and (3)(vii) amended 64903
243.4 (b)(2) removed; (b)(3) through (9) redesignated as (b)(2) through (8); new (b)(5) revised; new (b)(8) amended 64903
250.0 (r), (t) and (v) removed; (s), (u), (w), (x) and (y) redesignated as (r) through (v); (o), (p), (q) and new (r) through (u) revised 49926
250.18 (d) introductory text revised; (d)(4) through (8) added 44764
(d)(1), (2) and (3) revised; (d)(4) and (5) added 49927
250.51 (a)(3) amended 49927
250.64 (a) and (f) introductory text revised 49927
250.65 (a), (b) and (c) amended 49928
250.66 (b) and (e) amended 49928

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250.83 (a) and (b) introductory text amended; (c) revised; (d) added 49928
250.85 (a) amended 49928
250.103 (a), (b) introductory text and (c) introductory text amended; (d) revised 49928
250.105 (a) amended 49928
250.111 Introductory text amended 49928
250.114 (b) amended 49928
250.121 (h)(1) amended 49928
250.172 (a)(1), (b)(2), (3), (5) and (6) revised; (a)(2), (3), (6), (7) and (8) amended; (a)(9), (b)(8) and (9) added 49928
250.260 (b)(3) amended 49928
250.272 (a) and (c) introductory text amended 49928
250.273 (a), (b) and (c) amended 49928
250.274 (b) amended 49928
250.282 (a), (b) introductory text, (c)(1) and (2) amended 49928
254 Added; interim; eff. to 2–18–95 7490
256 Heading revised 45261
Authority citation revised 45261
256.0—256.12 (Subpart A) Heading revised 45261
256.0 Revised 45261
256.58 Heading, (a), (c) and (e) revised; (f) redesignated as (h); new (f) and (g) added 45261
256.59 Revised 45262
256.61 Revised 45262
256.62 (e) revised 45262

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401 Authority citation revised 27204
401.3 Amended 27204
401.4 Revised 27204
401.6 (c)(2) revised 27204
401.11 (a) and (g) revised 27204
401.12 (c) revised 27204
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206 Extraordinary cost provisions 17479

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216 Authority citation revised 38905
216.40 (b) revised 38905
218 Authority citation revised 14559, 38906
218.40 (b) revised 38906
218.202 (c) and (d) revised 14559
218.302 (c) and (d) revised 14559
230 Authority citation revised 38363
230.451—230.461 (Subpart J) Added 38363
250 Authority citation revised 53093
250.2 Amended 53093
250.18 (d) revised 12161
250.26 Added 53093
250.33 (b)(15) and (o) revised 53093
250.34 (b)(8)(v)(A) and (s) revised 53093
250.157 (a)(5) revised 53094
250.159 (c)(4) revised 53094
250.211 Amended 64850
250.212 (a)(2) amended 64850
250.213 Amended 64850
250.214 Amended 64850
256 Authority citation revised 53094
256.23 (b) amended 53094
280 Authority citation revised 53094
280.2 Amended 53094
281 Authority citation revised 53094
281.12 (c) amended 53094

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Guidance availability 36711
218.53 Added 3087
218.203 Added 3087
250 Interpretation 9298
254 Regulation at 58 FR 7490 eff. date extended 9626

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202 Authority citation revised 5490
202.151 (a) revised 5490

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203 Comment period extension 48834
203.1 (Subpart A) Added; interim 27274
(Subpart A) Comment period extension 40734
203.50—203.56 (Subpart B) Revised; interim 27274
206 Authority citation revised 3804, 5455
206.50—206.55 (Subpart B) Added 5455
(Subpart B) Comment period extension 40734
206.100—206.105 (Subpart C) Heading revised 5462
206.100 (a), (b) and (c) revised 5462
206.101 Amended 5462
206.102 (a)(2) removed; (a)(1) redesignated as (a); (d), (i), (k) and (l) revised 5462
206.104 (b)(2) and (d) revised 5462
206.105 (c)(1)(ii), (iii), (v), (vi), (2)(ii), (iii), (v), (vii), (3) and (4) removed; (c)(1)(iv), (2)(iv), (vi) and (viii) redesignated as (c)(1)(ii), (2)(ii), (iii) and (iv); (a)(1)(i), (3), (b)(1), (2)(v), (4), (c)(1)(i), (2)(i), new (ii), new (iii), (d) and (e) revised 5463
206.106 Added 3804
206.150—206.159 (Subpart D) Heading revised 5464
206.150 Revised 5464
206.151 Amended 5464
206.152 (a)(2), (e)(2), (h), (i), (k) and (l) revised; (a)(3) removed 5464
206.153 (a)(3) removed; (e)(2), (i), (k) and (l) revised 5465
206.154 (c)(4) revised 5465
206.155 (b) revised 5465
206.156 (c)(3) and (d) revised 5465
206.157 (c)(1)(ii), (iii), (v), (vi), (2)(ii), (iii), (v), (vii), (3) and (4) removed; (c)(1)(iv), (2)(iv), (vi) and (viii) redesignated as (c)(1)(ii), (2)(ii), (iii) and (iv); (a)(1)(i), (3), (b)(1), (2)(v), (4), (c)(1)(i), (2)(i), new (ii), new (iii), (d), (e)(1) and (2) revised 5465
206.158 (c)(3) and (e) revised 5466

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206.159 (c)(1)(ii), (iii), (v), (vi), (2)(ii), (iii), (v), (vii), (3) and (4) removed; (c)(1)(iv), (2)(iv), (vi) and (viii) redesignated as (c)(1)(ii), (2)(ii), (iii) and (iv); (a)(1)(i), (3), (b)(1), (2)(v), (c)(1)(i), (2)(i), new (ii), new (iii), (d), (e)(1) and (2) revised 5466
206.160 Added 3804
206.170—206.179 (Subpart E) Added 5467
206.250—206.265 (Subpart F) Heading revised 5479
206.250 (d) removed; (a) and (b) revised 5479
206.251 Amended 5479
206.253 (a) and (c) revised 5479
206.255 (a) and (b) revised 5480
206.256 (a) revised 5480
206.257 (a), (d)(2), (h), (j) and (k) revised 5480
206.258 (c) revised 5480
206.259 (c)(1)(ii), (iii), (v), (vi), (2)(ii), (iii), (v), (vii), (3) and (4) removed; (c)(1)(iv), (2)(iv) and (vi) redesignated as (c)(1)(ii), (2)(ii) and (iii); (a)(1), (b)(1), (2)(v), (c)(1)(i), (2)(i), new (ii), new (iii), (d) and (e)(1) revised 5480
206.261 (a)(1), (2) and (e) revised 5481
206.262 (c)(1)(ii), (iii), (v), (vi), (2)(ii), (iii), (v), (vii), (3) and (4) removed; (c)(1)(iv), (2)(iv), (vi) and (viii) redesignated as (c)(1)(ii), (2)(ii), (iii) and (v); (a)(1), (b)(1), (2)(v), (b)(3), (c)(1)(i), (2)(i), new (ii), new (iii), (d) and (e) revised 5481
206.450—206.464 (Subpart J) Added 5481
250.1 Introductory text amended; (a)(1), (b), (c)(1) through (4), (6), (d), (e)(1) through (5), (f)(1) and (g)(2) revised 60022
250.13 Revised 55887
250.53 (b) revised 60024
250.122 (e)(4)(i) introductory text revised 60024
250.123 (b)(9)(i) revised 60025
250.126 (c)(3), (e)(2) and (3) revised 60025

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250.137 (b)(1)(ii), (c)(4)(ii) and (vii) revised 60025
250.138 (b)(4)(i), (6)(i), (7), (8)(i), (9), (10), (c)(3), (d)(1)(v), (5) through (9), (e)(1)(i) and (2)(i) revised 60025
250.175 Revised 25148
250.180 (c)(6)(i), (ii), (v), (vi), (viii)(A), (C), (d)(3)(iv), (v)(B), (f)(2)(i), (ii), (iv), (v) and (vii) revised 60026
250.181 (c)(1) revised 60026
250.291 (b)(3) and (d)(4)(i) revised 60026
250.292 (b)(4)(i) revised 60026
256.37 (a) concluding text removed; (a)(2) revised; (a)(3) added 55889
256.47 (e)(2) revised 34732
260 Authority citation revised 3804
260.001 Revised 3804
260.002 Amended 3804
260.102 Amended; interim 12027
260.110 (a)(1)(iii), (2)(iii), (3)(i)(C)(*4*) and (iii) revised; (a)(5), (6) and (7) added 3804
(d) added; interim 12027

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218 Authority citation revised 19498
218.51 Revised 19498
218.155 (b)(1) amended 19499
250 Authority citation revised 27954
250.1 (c)(7) and (g)(1) revised 3795
(c)(4) designation corrected, (d)(61) corrected 33156
250.2 Amended 3795
250.8 Revised; eff. 8–20–97 27954
250.13 (b)(2) corrected 35247
250.19 (a) amended 13996
250.33 (b)(2) revised 13996
250.34 (b)(3) revised 13996
250.41 Heading revised; (b) and (c) removed 13996
250.42 Removed 13996
250.43 Removed 13996

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250.67 Revised 3795
250.110 Existing text designated as (a); (b) added; eff. 8–20–97 27955
250.124 (a)(3)(i) revised 5331
250.159 (b)(1) revised; eff. 8–20–97 27955
250.175 Heading revised; (f) added 3800
250.190—250.194 (Subpart M) Revised 5331
250.209—250.232 (Subpart O) Revised 5322
250.214 Corrected 7298
250.228 (a)(4)(i) and (iii) corrected 7298
250.229 Corrected 7298
251 Authority citation revised 27955
251.6–4 Revised; eff. 8–20–97 27955
254 Revised 13996
254.9 (d) correctly revised 18041
256.7 (b) through (h) redesignated as (c) through (i); new (b) added; eff. 8–20–97 27955
256.47 (f) amended; eff 8–20–97 27955
256.52 Redesignated from 256.58 and revised; eff. 8–20–97 27955
256.53 Redesignated from 256.61; (a) introductory text, (b) introductory text, (e), and (f) added; (a)(1), (b)(1) and (d) revised; eff. 8–20–97 27956
256.54 Redesignated from 256.59 and revised; eff. 8–20–97 27956
256.55 Added; eff. 8–20–97 27957
256.56 Added; eff. 8–20–97 27957
256.57 Added; eff. 8–20–97 27957
256.58 Redesignated as 256.52; eff. 8–20–97 27955
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256.59 Redesignated as 256.54; eff. 8–20–97 27956
Added; eff. 8–20–97 27958
256.61 Redesignated as 256.53; eff. 8–20–97 27956
256.62 Heading, (a), (d) and (e) revised; introductory text and (f) added; eff. 8–20–97 27959
256.64 Introductory text and (a) introductory text amended; (a)(2) and (d) through (h) redesignated as (8) and (e) through (i); eff. 8–20–97 27959

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281 Authority citation revised 27960

281.33 (b) introductory text amended; eff. 8–20–97 27960

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282 Authority citation revised 27960

282.40 (b) amended; eff. 8–20–97 27960

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