AUTHENTICATED
U.S. GOVERNMENT
INFORMATION
GPO

CODE OF FEDERAL REGULATIONS

Title 30
Mineral Resources

Parts 200 to 699

Revised as of July 1, 2022

Containing a codification of documents
of general applicability and future effect

As of July 1, 2022

Published by the Office of the Federal Register
National Archives and Records Administration
as a Special Edition of the Federal Register

U.S. GOVERNMENT OFFICIAL EDITION NOTICE

Legal Status and Use of Seals and Logos

The seal of the National Archives and Records Administration (NARA) authenticates the Code of Federal Regulations (CFR) as the official codification of Federal regulations established under the Federal Register Act. Under the provisions of 44 U.S.C. 1507, the contents of the CFR, a special edition of the Federal Register, shall be judicially noticed. The CFR is prima facie evidence of the original documents published in the Federal Register (44 U.S.C. 1510).

It is prohibited to use NARA's official seal and the stylized Code of Federal Regulations logo on any republication of this material without the express, written permission of the Archivist of the United States or the Archivist's designee. Any person using NARA's official seals and logos in a manner inconsistent with the provisions of 36 CFR part 1200 is subject to the penalties specified in 18 U.S.C. 506, 701, and 1017.

Use of ISBN Prefix

This is the Official U.S. Government edition of this publication and is herein identified to certify its authenticity. Use of the 0–16 ISBN prefix is for U.S. Government Publishing Office Official Editions only. The Superintendent of Documents of the U.S. Government Publishing Office requests that any reprinted edition clearly be labeled as a copy of the authentic work with a new ISBN.

GPO U.S. GOVERNMENT PUBLISHING OFFICE

U.S. Superintendent of Documents • Washington, DC 20402–0001

http://bookstore.gpo.gov

Phone: toll-free (866) 512-1800; DC area (202) 512-1800

Table of contents

	Page
Explanation	v
Title 30:	
Chapter II—Bureau of Safety and Environmental Enforcement, Department of the Interior	3
Chapter IV—Geological Survey, Department of the Interior	325
Chapter V—Bureau of Ocean Energy Management, Department of the Interior	337
Finding Aids:	
Table of CFR Titles and Chapters	625
Alphabetical List of Agencies Appearing in the CFR	645
List of CFR Sections Affected	655

Cite this Code: CFR

To cite the regulations in this volume use title, part and section number. Thus, 30 CFR 203.0 *refers to title 30, part 203, section 0.*

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.

LEGAL STATUS

The contents of the Federal Register are required to be judicially noticed (44 U.S.C. 1507). The Code of Federal Regulations is prima facie evidence of the text of the original documents (44 U.S.C. 1510).

HOW TO USE THE CODE OF FEDERAL REGULATIONS

The Code of Federal Regulations is kept up to date by the individual issues of the Federal Register. These two publications must be used together to determine the latest version of any given rule.

To determine whether a Code volume has been amended since its revision date (in this case, July 1, 2022), consult the ''List of CFR Sections Affected (LSA),'' which is issued monthly, and the ''Cumulative List of Parts Affected,'' which appears in the Reader Aids section of the daily Federal Register. These two lists will identify the Federal Register page number of the latest amendment of any given rule.

EFFECTIVE AND EXPIRATION DATES

Each volume of the Code contains amendments published in the Federal Register since the last revision of that volume of the Code. Source citations for the regulations are referred to by volume number and page number of the Federal Register and date of publication. Publication dates and effective dates are usually not the same and care must be exercised by the user in determining the actual effective date. In instances where the effective date is beyond the cutoff date for the Code a note has been inserted to reflect the future effective date. In those instances where a regulation published in the Federal Register states a date certain for expiration, an appropriate note will be inserted following the text.

OMB CONTROL NUMBERS

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

Many agencies have begun publishing numerous OMB control numbers as amendments to existing regulations in the CFR. These OMB numbers are placed as close as possible to the applicable recordkeeping or reporting requirements.

PAST PROVISIONS OF THE CODE

Provisions of the Code that are no longer in force and effect as of the revision date stated on the cover of each volume are not carried. Code users may find the text of provisions in effect on any given date in the past by using the appropriate List of CFR Sections Affected (LSA). For the convenience of the reader, a ''List of CFR Sections Affected'' is published at the end of each CFR volume. For changes to the Code prior to the LSA listings at the end of the volume, consult previous annual editions of the LSA. For changes to the Code prior to 2001, consult the List of CFR Sections Affected compilations, published for 1949-1963, 1964-1972, 1973-1985, and 1986-2000.

''[RESERVED]'' TERMINOLOGY

The term ''[Reserved]'' is used as a place holder within the Code of Federal Regulations. An agency may add regulatory information at a ''[Reserved]'' location at any time. Occasionally ''[Reserved]'' is used editorially to indicate that a portion of the CFR was left vacant and not dropped in error.

INCORPORATION BY REFERENCE

What is incorporation by reference? Incorporation by reference was established by statute and allows Federal agencies to meet the requirement to publish regulations in the Federal Register by referring to materials already published elsewhere. For an incorporation to be valid, the Director of the Federal Register must approve it. The legal effect of incorporation by reference is that the material is treated as if it were published in full in the Federal Register (5 U.S.C. 552(a)). This material, like any other properly issued regulation, has the force of law.

What is a proper incorporation by reference? The Director of the Federal Register will approve an incorporation by reference only when the requirements of 1 CFR part 51 are met. Some of the elements on which approval is based are:

(a) The incorporation will substantially reduce the volume of material published in the Federal Register.

(b) The matter incorporated is in fact available to the extent necessary to afford fairness and uniformity in the administrative process.

(c) The incorporating document is drafted and submitted for publication in accordance with 1 CFR part 51.

What if the material incorporated by reference cannot be found? If you have any problem locating or obtaining a copy of material listed as an approved incorporation by reference, please contact the agency that issued the regulation containing that incorporation. If, after contacting the agency, you find the material is not available, please notify the Director of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001, or call 202-741-6010.

CFR INDEXES AND TABULAR GUIDES

A subject index to the Code of Federal Regulations is contained in a separate volume, revised annually as of January 1, entitled CFR INDEX AND FINDING AIDS. This volume contains the Parallel Table of Authorities and Rules. A list of CFR titles, chapters, subchapters, and parts and an alphabetical list of agencies publishing in the CFR are also included in this volume.

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

The Federal Register Index is issued monthly in cumulative form. This index is based on a consolidation of the ''Contents'' entries in the daily Federal Register.

A List of CFR Sections Affected (LSA) is published monthly, keyed to the revision dates of the 50 CFR titles.

REPUBLICATION OF MATERIAL

There are no restrictions on the republication of material appearing in the Code of Federal Regulations.

INQUIRIES

For a legal interpretation or explanation of any regulation in this volume, contact the issuing agency. The issuing agency's name appears at the top of odd-numbered pages.

For inquiries concerning CFR reference assistance, call 202–741–6000 or write to the Director, Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001 or e-mail *fedreg.info@nara.gov*.

SALES

The Government Publishing Office (GPO) processes all sales and distribution of the CFR. For payment by credit card, call toll-free, 866-512-1800, or DC area, 202-512-1800, M-F 8 a.m. to 4 p.m. e.s.t. or fax your order to 202-512-2104, 24 hours a day. For payment by check, write to: US Government Publishing Office – New Orders, P.O. Box 979050, St. Louis, MO 63197-9000.

ELECTRONIC SERVICES

The full text of the Code of Federal Regulations, the LSA (List of CFR Sections Affected), The United States Government Manual, the Federal Register, Public Laws, Public Papers of the Presidents of the United States, Compilation of Presidential Documents and the Privacy Act Compilation are available in electronic format via *www.govinfo.gov*. For more information, contact the GPO Customer Contact Center, U.S. Government Publishing Office. Phone 202-512-1800, or 866-512-1800 (toll-free). E-mail, *ContactCenter@gpo.gov*.

The Office of the Federal Register also offers a free service on the National Archives and Records Administration's (NARA) website for public law numbers, Federal Register finding aids, and related information. Connect to NARA's website at *www.archives.gov/federal-register*.

The eCFR is a regularly updated, unofficial editorial compilation of CFR material and Federal Register amendments, produced by the Office of the Federal Register and the Government Publishing Office. It is available at *www.ecfr.gov*.

OLIVER A. POTTS,
Director,
Office of the Federal Register
July 1, 2022

THIS TITLE

Title 30—MINERAL RESOURCES is composed of three volumes. The parts in these volumes are arranged in the following order: parts 1—199, parts 200—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, 2022.

For this volume, Cheryl E. Sirofchuck was Chief Editor. The Code of Federal Regulations publication program is under the direction of John Hyrum Martinez, assisted by Stephen J. Frattini.

Title 30—Mineral Resources

(This book contains parts 200 to 699)

Part

CHAPTER II—Bureau of Safety and Environmental Enforcement, Department of the Interior 203

CHAPTER IV—Geological Survey, Department of the Interior 401

CHAPTER V—Bureau of Ocean Energy Management, Department of the Interior 519

CHAPTER II—BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT, DEPARTMENT OF THE INTERIOR

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

Part		*Page*
200–202	[Reserved]	
203	Relief or reduction in royalty rates	5
219	[Reserved]	

SUBCHAPTER B—OFFSHORE

250	Oil and gas and sulphur operations in the Outer Continental Shelf	44
251	Geological and geophysical (G&G) explorations of the Outer Continental Shelf	277
252	Outer Continental Shelf (OCS) Oil and Gas Information Program	282
253	[Reserved]	
254	Oil-spill response requirements for facilities located seaward of the coast line	288
256	Leasing of sulphur or oil and gas in the Outer Continental Shelf	302
259–260	[Reserved]	
270	Nondiscrimination in the Outer Continental Shelf	304
280	Prospecting for minerals other than oil, gas, and sulphur on the Outer Continental Shelf	306
281	[Reserved]	
282	Operations in the Outer Continental Shelf for minerals other than oil, gas, and sulphur	307
285	[Reserved]	

SUBCHAPTER C—APPEALS

290	Appeal procedures	318
291	Open and nondiscriminatory access to oil and gas pipelines under the Outer Continental Shelf Lands Act	319
292–299	[Reserved]	

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

PARTS 200–202 [RESERVED]

PART 203—RELIEF OR REDUCTION IN ROYALTY RATES

Subpart A—General Provisions

Sec.
203.0 What definitions apply to this part?
203.1 What is BSEE's authority to grant royalty relief?
203.2 How can I obtain royalty relief?
203.3 Do I have to pay a fee to request royalty relief?
203.4 How do the provisions in this part apply to different types of leases and projects?
203.5 What is BSEE's authority to collect information?

Subpart B—OCS Oil, Gas, and Sulfur General

ROYALTY RELIEF FOR DRILLING ULTRA-DEEP WELLS ON LEASES NOT SUBJECT TO DEEP WATER ROYALTY RELIEF

203.30 Which leases are eligible for royalty relief as a result of drilling a phase 2 or phase 3 ultra-deep well?
203.31 If I have a qualified phase 2 or qualified phase 3 ultra-deep well, what royalty relief would that well earn for my lease?
203.32 What other requirements or restrictions apply to royalty relief for a qualified phase 2 or phase 3 ultra-deep well?
203.33 To which production do I apply the RSV earned by qualified phase 2 and phase 3 ultra-deep wells on my lease or in my unit?
203.34 To which production may an RSV earned by qualified phase 2 and phase 3 ultra-deep wells on my lease not be applied?
203.35 What administrative steps must I take to use the RSV earned by a qualified phase 2 or phase 3 ultra-deep well?
203.36 Do I keep royalty relief if prices rise significantly?

ROYALTY RELIEF FOR DRILLING DEEP GAS WELLS ON LEASES NOT SUBJECT TO DEEP WATER ROYALTY RELIEF

203.40 Which leases are eligible for royalty relief as a result of drilling a deep well or a phase 1 ultra-deep well?
203.41 If I have a qualified deep well or a qualified phase 1 ultra-deep well, what royalty relief would my lease earn?
203.42 What conditions and limitations apply to royalty relief for deep wells and phase 1 ultra-deep wells?
203.43 To which production do I apply the RSV earned from qualified deep wells or qualified phase 1 ultra-deep wells on my lease?
203.44 What administrative steps must I take to use the royalty suspension volume?
203.45 If I drill a certified unsuccessful well, what royalty relief will my lease earn?
203.46 To which production do I apply the royalty suspension supplements from drilling one or two certified unsuccessful wells on my lease?
203.47 What administrative steps do I take to obtain and use the royalty suspension supplement?
203.48 Do I keep royalty relief if prices rise significantly?
203.49 May I substitute the deep gas drilling provisions in this part for the deep gas royalty relief provided in my lease terms?

ROYALTY RELIEF FOR END-OF-LIFE LEASES

203.50 Who may apply for end-of-life royalty relief?
203.51 How do I apply for end-of-life royalty relief?
203.52 What criteria must I meet to get relief?
203.53 What relief will BSEE grant?
203.54 How does my relief arrangement for an oil and gas lease operate if prices rise sharply?
203.55 Under what conditions can my end-of-life royalty relief arrangement for an oil and gas lease be ended?
203.56 Does relief transfer when a lease is assigned?

ROYALTY RELIEF FOR PRE-ACT DEEP WATER LEASES AND FOR DEVELOPMENT AND EXPANSION PROJECTS

203.60 Who may apply for royalty relief on a case-by-case basis in deep water in the Gulf of Mexico or offshore of Alaska?
203.61 How do I assess my chances for getting relief?
203.62 How do I apply for relief?
203.63 Does my application have to include all leases in the field?
203.64 How many applications may I file on a field or a development project?
203.65 How long will BSEE take to evaluate my application?
203.66 What happens if BSEE does not act in the time allowed?
203.67 What economic criteria must I meet to get royalty relief on an authorized field or project?
203.68 What pre-application costs will BSEE consider in determining economic viability?

203.69 If my application is approved, what royalty relief will I receive?
203.70 What information must I provide after BSEE approves relief?
203.71 How does BSEE allocate a field's suspension volume between my lease and other leases on my field?
203.72 Can my lease receive more than one suspension volume?
203.73 How do suspension volumes apply to natural gas?
203.74 When will BSEE reconsider its determination?
203.75 What risk do I run if I request a redetermination?
203.76 When might BSEE withdraw or reduce the approved size of my relief?
203.77 May I voluntarily give up relief if conditions change?
203.78 Do I keep relief approved by BSEE under this part for my lease, unit or project if prices rise significantly?
203.79 How do I appeal BSEE's decisions related to royalty relief for a deepwater lease or a development or expansion project?
203.80 When can I get royalty relief if I am not eligible for royalty relief under other sections in the subpart?

REQUIRED REPORTS

203.81 What supplemental reports do royalty-relief applications require?
203.82 What is BSEE's authority to collect this information?
203.83 What is in an administrative information report?
203.84 What is in a net revenue and relief justification report?
203.85 What is in an economic viability and relief justification report?
203.86 What is in a G&G report?
203.87 What is in an engineering report?
203.88 What is in a production report?
203.89 What is in a cost report?
203.90 What is in a fabricator's confirmation report?
203.91 What is in a post-production development report?

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F [Reserved]

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; 42 U.S.C. 15903–15906; 43 U.S.C. 1301 *et seq.;* 43 U.S.C. 1331 *et seq.;* and 43 U.S.C. 1801 *et seq.*

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Subpart A—General Provisions

§ 203.0 What definitions apply to this part?

Authorized field means a field:

(1) Located in a water depth of at least 200 meters and in the Gulf of Mexico (GOM) west of 87 degrees, 30 minutes West longitude;

(2) That includes one or more pre-Act leases; and

(3) From which no current pre-Act lease produced, other than test production, before November 28, 1995.

Certified unsuccessful well means an original well or a sidetrack with a sidetrack measured depth (*i.e.*, length) of at least 10,000 feet, on your lease that:

(1) You begin drilling on or after March 26, 2003, and before May 3, 2009, on a lease that is located in water partly or entirely less than 200 meters deep and that is not a non-converted lease, or on or after May 18, 2007, and before May 3, 2013, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep;

(2) You begin drilling before your lease produces gas or oil from a well with a perforated interval the top of which is at least 18,000 feet true vertical depth subsea (TVD SS), (*i.e.*, below the datum at mean sea level);

(3) You drill to at least 18,000 feet TVD SS with a target reservoir on your lease, identified from seismic and related data, deeper than that depth;

(4) Fails to meet the producibility requirements of 30 CFR part 550, subpart A, and does not produce gas or oil, or meets those producibility requirements and Bureau of Ocean Energy Management (BOEM) agrees it is not commercially producible; and

(5) For which you have provided the notices and information required under § 203.47.

Complete application means an original and two copies of the six reports consisting of the data specified in §§ 203.81, 203.83, and 203.85 through 203.89, along with one set of digital information, which Bureau of Safety and Environmental Enforcement (BSEE) has reviewed and found complete.

Deep well means either an original well or a sidetrack with a perforated interval the top of which is at least 15,000 feet TVD SS and less than 20,000 feet TVD SS. A deep well subsequently re-perforated at less than 15,000 feet TVD SS in the same reservoir is still a deep well.

Determination means the binding decision by BSEE on whether your field qualifies for relief or how large a royalty-suspension volume must be to make the field economically viable.

Development project means a project to develop one or more oil or gas reservoirs located on one or more contiguous leases that have had no production (other than test production) before the current application for royalty relief and are either:

(1) Located in a planning area offshore Alaska; or

(2) Located in the GOM in a water depth of at least 200 meters and wholly west of 87 degrees, 30 minutes West longitude, and were issued in a sale held after November 28, 2000.

Draft application means the preliminary set of information and assumptions you submit to seek a nonbinding assessment on whether a field could be expected to qualify for royalty relief.

Eligible lease means a lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 1995, and before November 28, 2000;

(2) Is located in the Gulf of Mexico in water depths of 200 meters or deeper;

(3) Lies wholly west of 87 degrees, 30 minutes West longitude; and

(4) Is offered subject to a royalty suspension volume.

Expansion project means a project that meets the following requirements:

(1) You must propose the project in a (BOEM) Development and Production Plan, a BOEM Development Operations Coordination Document (DOCD), or a BOEM Supplement to a DOCD, approved by the Secretary of the Interior after November 28, 1995.

(2) The project must be located on either:

(i) A pre-Act lease in the GOM, or a lease in the GOM issued in a sale held after November 28, 2000, located wholly west of 87 degrees, 30 minutes West longitude; or

(ii) A lease in a planning area offshore Alaska.

(3) On a pre-Act lease in the GOM, the project:

(i) Must significantly increase the ultimate recovery of resources from one or more reservoirs that have not previously produced (extending recovery from reservoirs already in production does not constitute a significant increase); and

(ii) Must involve a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, *etc.*).

(4) For a lease issued in a planning area offshore Alaska, or in the GOM after November 28, 2000, the project must involve a new well drilled into a reservoir that has not previously produced.

(5) On a lease in the GOM, the project must not include a reservoir the production from which an RSV under §§ 203.30 through 203.36 or §§ 203.40 through 203.48 would be applied.

Fabrication (or start of construction) means evidence of an irreversible commitment to a concept and scale of development. Evidence includes copies of a binding contract between you (as applicant) and a fabrication yard, a letter from a fabricator certifying that continuous construction has begun, and a receipt for the customary down payment.

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

Lease means a lease or unit.

New production means any production from a current pre-Act lease from which no royalties are due on production, other than test production, before November 28, 1995. Also, it means any

additional production resulting from new lease-development activities on a lease issued in a sale after November 28, 2000, or a current pre-Act lease under a BOEM DOCD or a BOEM Supplement approved by the Secretary of the Interior after November 28, 1995.

Nonbinding assessment means an opinion by BSEE of whether your field could qualify for royalty relief. It is based on your draft application and does not entitle the field to relief.

Non-converted lease means a lease located partly or entirely in water less than 200 meters deep issued in a lease sale held after January 1, 2001, and before January 1, 2004, whose original lease terms provided for an RSV for deep gas production and the lessee has not exercised the option under § 203.49 to replace the lease terms for royalty relief with those in § 203.0 and §§ 203.40 through 203.48.

Original well means a well that is drilled without utilizing an existing wellbore. An original well includes all sidetracks drilled from the original wellbore either before the drilling rig moves off the well location or after a temporary rig move that BSEE agrees was forced by a weather or safety threat and drilling resumes within 1 year. A bypass from an original well (e.g., drilling around material blocking the hole or to straighten crooked holes) is part of the original well.

Participating area means that part of the unit area that BSEE determines is reasonably proven by drilling and completion of producible wells, geological and geophysical information, and engineering data to be capable of producing hydrocarbons in paying quantities.

Performance conditions mean minimum conditions you must meet, after we have granted relief and before production begins, to remain qualified for that relief. If you do not meet each one of these performance conditions, we consider it a change in material fact significant enough to invalidate our original evaluation and approval.

Phase 1 ultra-deep well means an ultra-deep well on a lease that is located in water partly or entirely less than 200 meters deep for which drilling began before May 18, 2007, and that begins production before May 3, 2009, or that meets the requirements to be a certified unsuccessful well.

Phase 2 ultra-deep well means an ultra-deep well for which drilling began on or after May 18, 2007; and that either meets the requirements to be a certified unsuccessful well or that begins production:

(1) Before the date which is 5 years after the lease issuance date on a non-converted lease; or

(2) Before May 3, 2009, on all other leases located in water partly or entirely less than 200 meters deep; or

(3) Before May 3, 2013, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

Phase 3 ultra-deep well means an ultra-deep well for which drilling began on or after May 18, 2007, and that begins production:

(1) On or after the date which is 5 years after the lease issuance date on a non-converted lease; or

(2) On or after May 3, 2009, on all other leases located in water partly or entirely less than 200 meters deep; or

(3) On or after May 3, 2013, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

Pre-Act lease means a lease that:

(1) Results from a sale held before November 28, 1995;

(2) Is located in the GOM in water depths of 200 meters or deeper; and

(3) Lies wholly west of 87 degrees, 30 minutes West longitude.

Production means all oil, gas, and other relevant products you save, remove, or sell from a tract or those quantities allocated to your tract under a unitization formula, as measured for the purposes of determining the amount of royalty payable to the United States.

Project means any activity that requires at least a permit to drill.

Qualified deep well means:

(1) On a lease that is located in water partly or entirely less than 200 meters deep that is not a non-converted lease, a deep well for which drilling began on or after March 26, 2003, that produces natural gas (other than test production), including gas associated with oil production, before May 3, 2009, and for

which you have met the requirements prescribed in § 203.44;

(2) On a non-converted lease, a deep well that produces natural gas (other than test production) before the date which is 5 years after the lease issuance date from a reservoir that has not produced from a deep well on any lease; or

(3) On a lease that is located in water entirely more than 200 meters but entirely less than 400 meters deep, a deep well for which drilling began on or after May 18, 2007, that produces natural gas (other than test production), including gas associated with oil production before May 3, 2013, and for which you have met the requirements prescribed in § 203.44.

Qualified ultra-deep well means:

(1) On a lease that is located in water partly or entirely less than 200 meters deep that is not a non-converted lease, an ultra-deep well for which drilling began on or after March 26, 2003, that produces natural gas (other than test production), including gas associated with oil production, and for which you have met the requirements prescribed in § 203.35 or § 203.44, as applicable; or

(2) On a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep, or on a non-converted lease, an ultra-deep well for which drilling began on or after May 18, 2007, that produces natural gas (other than test production), including gas associated with oil production, and for which you have met the requirements prescribed in § 203.35.

Qualified well means either a qualified deep well or a qualified ultra-deep well.

Redetermination means our reconsideration of our determination on royalty relief because you request it after:

(1) We have rejected your application;

(2) We have granted relief but you want a larger suspension volume;

(3) We withdraw approval; or

(4) You renounce royalty relief.

Renounce means action you take to give up relief after we have granted it and before you start production.

Reservoir means an underground accumulation of oil or natural gas, or both, characterized by a single pressure system and segregated from other such accumulations.

Royalty suspension (RS) lease means a lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 2000;

(2) Is in locations or planning areas specified in a particular Notice of OCS Lease Sale offering that lease; and

(3) Is offered subject to a royalty suspension specified in a Notice of OCS Lease Sale published in the FEDERAL REGISTER.

Royalty suspension supplement (RSS) means a royalty suspension volume resulting from drilling a certified unsuccessful well that is applied to future natural gas and oil production generated at any drilling depth on, or allocated under a BSEE-approved unit agreement to, the same lease.

Royalty suspension volume (RSV) means a volume of production from a lease that is not subject to royalty under the provisions of this part.

Sidetrack means, for the purpose of this subpart, a well resulting from drilling an additional hole to a new objective bottom-hole location by leaving a previously drilled hole. A sidetrack also includes drilling a well from a platform slot reclaimed from a previously drilled well or re-entering and deepening a previously drilled well. A bypass from a sidetrack (e.g., drilling around material blocking the hole, or to straighten crooked holes) is part of the sidetrack.

Sidetrack measured depth means the actual distance or length in feet a sidetrack is drilled beginning where it exits a previously drilled hole to the bottom hole of the sidetrack, that is, to its total depth.

Sunk costs for an authorized field means the after-tax eligible costs that you (not third parties) incur for exploration, development, and production from the spud date of the first discovery on the field to the date we receive your complete application for royalty relief. The discovery well must be qualified as producible under 30 CFR part 550, subpart A. Sunk costs include the rig mobilization and material costs for the discovery well that you incurred before its spud date.

Sunk costs for an expansion or development project means the after-tax eligible costs that you (not third parties) incur for only the first well that encounters hydrocarbons in the reservoir(s) included in the application and that meets the producibility requirements under 30 CFR part 550, subpart A on each lease participating in the application. Sunk costs include rig mobilization and material costs for the discovery wells that you incurred before their spud dates.

Ultra-deep well means either an original well or a sidetrack completed with a perforated interval the top of which is at least 20,000 feet TVD SS. An ultra-deep well subsequently re-perforated less than 20,000 feet TVD SS in the same reservoir is still an ultra-deep well.

Withdraw means action we take on a field that has qualified for relief if you have not met one or more of the performance conditions.

§ 203.1 What is BSEE's authority to grant royalty relief?

The Outer Continental Shelf (OCS) Lands Act, 43 U.S.C. 1337, as amended by the OCS Deep Water Royalty Relief Act (DWRRA), Public Law 104–58 and the Energy Policy Act of 2005, Public Law 109–058 authorizes us to grant royalty relief in four situations.

(a) Under 43 U.S.C. 1337(a)(3)(A), we may reduce or eliminate any royalty or a net profit share specified for an OCS lease to promote increased production.

(b) Under 43 U.S.C. 1337(a)(3)(B), we may reduce, modify, or eliminate any royalty or net profit share to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases. This authority is restricted to leases in the GOM that are west of 87 degrees, 30 minutes West longitude, and in the planning areas offshore Alaska.

(c) Under 43 U.S.C. 1337(a)(3)(C), we may suspend royalties for designated volumes of new production from any lease if:

(1) Your lease is in deep water (water at least 200 meters deep);

(2) Your lease is in designated areas of the GOM (west of 87 degrees, 30 minutes West longitude);

(3) Your lease was acquired in a lease sale held before the DWRRA (before November 28, 1995);

(4) We find that your new production would not be economic without royalty relief; and

(5) Your lease is on a field that did not produce before enactment of the DWRRA, or if you propose a project to significantly expand production under a Development Operations Coordination Document (DOCD) or a supplementary DOCD, that the Bureau of Ocean Energy Management (BOEM) approved after November 28, 1995.

(d) Under 42 U.S.C. 15904–15905, we may suspend royalties for designated volumes of gas production from deep and ultra-deep wells on a lease if:

(1) Your lease is in shallow water (water less than 400 meters deep) and you produce from an ultra-deep well (top of the perforated interval is at least 20,000 feet TVD SS) or your lease is in waters entirely more than 200 meters and entirely less than 400 meters deep and you produce from a deep well (top of the perforated interval is at least 15,000 feet TVD SS);

(2) Your lease is in the designated area of the GOM (wholly west of 87 degrees, 30 minutes west longitude); and

(3) Your lease is not eligible for deep water royalty relief.

§ 203.2 How can I obtain royalty relief?

We may reduce or suspend royalties for Outer Continental Shelf (OCS) leases or projects that meet the criteria in the following table.

If you have a lease . . .	And if you . . .	Then we may grant you . . .
(a) With earnings that cannot sustain production (*i.e., End-of-life lease*),	Would abandon otherwise potentially recoverable resources but seek to increase production by operating beyond the point at which the lease is economic under the existing royalty rate,	A reduced royalty rate on current monthly production and a higher royalty rate on additional monthly production (see §§ 203.50 through 203.56).

If you have a lease . . .	And if you . . .	Then we may grant you . . .
(b) Located in a designated GOM deep water area (*i.e.,* 200 meters or greater) and acquired in a lease sale held before November 28, 1995, or after November 28, 2000,	Propose an expansion project and can demonstrate your project is uneconomic without royalty relief,	A royalty suspension for a minimum production volume plus any additional production large enough to make the project economic (see §§ 203.60 through 203.79).
(c) Located in a designated GOM deep water area and acquired in a lease sale held before November 28, 1995 *(Pre-Act lease),*	Are on a field from which no current pre-Act lease produced (other than test production) before November 28, 1995, *(Authorized field,)*	A royalty suspension for a minimum production volume plus any additional volume needed to make the field economic (see §§ 203.60 through 203.79).
(d) Located in a designated GOM deep water area and acquired in a lease sale held after November 28, 2000,	Propose a development project and can demonstrate that the suspension volume, if any, for your lease is not enough to make development economic,	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic (see §§ 203.60 through 203.79).
(e) Where royalty relief would recover significant additional resources or, offshore Alaska or in certain areas of the GOM, would enable development,	Are not eligible to apply for end-of-life or deep water royalty relief, but show us you meet certain eligibility conditions,	A royalty modification in size, duration, or form that makes your lease or project economic (see § 203.80).
(f) Located in a designated GOM shallow water area and acquired in a lease sale held before January 1, 2001, or after January 1, 2004, or have exercised an option to substitute for royalty relief in your lease terms,	Drill a deep well on a lease that is not eligible for deep water royalty relief and you have not previously produced oil or gas from a deep well or an ultra-deep well,	A royalty suspension for a volume of gas produced from successful deep and ultra-deep wells, or, for certain unsuccessful deep and ultra-deep wells, a smaller royalty suspension for a volume of gas or oil produced by all wells on your lease (see §§ 203.40 through 203.49).
(g) Located in a designated GOM shallow water area,	Drill and produce gas from an ultra-deep well on a lease that is not eligible for deep water royalty relief and you have not previously produced oil or gas from an ultra-deep well,	A royalty suspension for a volume of gas produced from successful ultra-deep and deep wells on your lease (see §§ 203.30 through 203.36).
(h) Located in planning areas offshore Alaska,	Propose an expansion project or propose a development project and can demonstrate that the project is uneconomic without relief or that the suspension volume, if any, for your lease is not enough to make development economic,	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic (see §§ 203.60, 203.62, 203.67 through 203.70, 203.73, and 203.76 through 203.79).

§ 203.3 Do I have to pay a fee to request royalty relief?

When you submit an application or ask for a preview assessment, you must include a fee to reimburse us for our costs of processing your application or assessment. Federal policy and law require us to recover the cost of services that confer special benefits to identifiable non-Federal recipients. The Independent Offices Appropriation Act (31 U.S.C. 9701), Office of Management and Budget Circular A–25, and the Omnibus Appropriations Bill (Pub. L. 104–134, 110 Stat. 1321, April 26, 1996) authorize us to collect these fees.

(a) We will specify the necessary fees for each of the types of royalty relief applications and possible BSEE audits in a Notice to Lessees. We will periodically update the fees to reflect changes in costs, as well as provide other information necessary to administer royalty relief.

(b) You must file all payments electronically through the *Fees for Services* page on the BSEE Web site at *http://www.bsee.gov*, and you must include a copy of the *Pay.gov* confirmation receipt page with your application or assessment.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36148, June 6, 2016]

§ 203.4 How do the provisions in this part apply to different types of leases and projects?

The tables in this section summarize the similar application and approval provisions for the discretionary end-of-life and deep water royalty relief programs in §§ 203.50 to 203.91. Because royalty relief for deep gas on leases not subject to deep water royalty relief, as provided for under §§ 203.40 to 203.48, does not involve an application, its provisions do not parallel the other two royalty relief programs and are not summarized in this section.

(a) We require the information elements indicated by an X in the following table and described in §§ 203.51, 203.62, and 203.81 through 203.89 for applications for royalty relief.

Information elements	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Administrative information report	X	X	X	X
(2) Net revenue and relief justification report (prescribed format)	X	.....	.....	
(3) Economic viability and relief justification report (Royalty Suspension Viability Program (RSVP) model inputs justified with Geological and Geophysical (G&G), Engineering, Production, & Cost reports)	.....	X	X	X
(4) G&G report	.....	X	X	X
(5) Engineering report	.....	X	X	X
(6) Production report	.....	X	X	X
(7) Deep water cost report	.....	X	X	X

(b) We require the confirmation elements indicated by an X in the following table and described in §§ 203.70, 203.81, 203.90 and 203.91 to retain royalty relief.

Confirmation elements	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Fabricator's confirmation report	.....	X	X	X
(2) Post-production development report approved by an independent certified public accountant (CPA) * * *	.....	X	X	X

(c) The following table indicates by an X, and §§ 203.50, 203.52, 203.60 and 203.67 describe, the prerequisites for our approval of your royalty relief application.

Approval conditions	End-of-life lease	Deep water		
		Expansion	Pre-act lease	Development project
(1) At least 12 of the last 15 months have the required level of production	X			
(2) Already producing	X	.....		
(3) A producible well into a reservoir that has not produced before	.....	X	X	X
(4) Royalties for qualifying months exceed 75 percent of net revenue (NR)	X	.....	.....	
(5) Substantial investment on a pre-Act lease (e.g., platform, subsea template)	.....	.....	.....	
(6) Determined to be economic only with relief	.....	X	X	X

(d) The following table indicates by an X, and §§ 203.52, 203.74, and 203.75 describe, the prerequisites for a redetermination of our royalty relief decision.

Redetermination conditions	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) After 12 months under current rate, criteria same as for approval	X	.....	.....	
(2) For material change in geologic data, prices, costs, or available technology	.....	X	X	X

(e) The following table indicates by an X, and §§ 203.53 and 203.69 describe, the characteristics of approved royalty relief.

Relief rate and volume, subject to certain conditions	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) One-half pre-application effective lease rate on the qualifying amount, 1.5 times pre-application effective lease rate on additional production up to twice the qualifying amount, and the pre-application effective lease rate for any larger volumes	X			
(2) Qualifying amount is the average monthly production for 12 qualifying months	X			
(3) Zero royalty rate on the suspension volume and the original lease rate on additional production		X	X	X
(4) Suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)			X	
(5) Suspension volume is at least the minimum set in the Notice of Sale, the lease, or the regulations		X		X
(6) Amount needed to become economic		X	X	X

(f) The following table indicates by an X, and §§ 203.54 and 203.78 describe, circumstances under which we discontinue your royalty relief.

Full royalty resumes when	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Average NYMEX price for last 12 months is at least 25 percent above the average for the qualifying months.	X			
(2) Average NYMEX price for last calendar year exceeds $28/bbl or $3.50/mcf, escalated by the gross domestic product (GDP) deflator since 1994		X	X	
(3) Average prices for designated periods exceed levels we specify in the Notice of Sale or the lease		X		X

(g) The following table indicates by an X, and §§ 203.55, 203.76, and 203.77 describe, circumstances under which we end or reduce royalty relief.

Relief withdrawn or reduced	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) If recipient requests	X	X	X	X
(2) Lease royalty rate is at the effective rate for 12 consecutive months	X			
(3) Conditions occur that we specified in the approval letter in individual cases	X			
(4) Recipient does not submit post-production report that compares expected to actual costs		X	X	X
(5) Recipient changes development system		X	X	X
(6) Recipient excessively delays starting fabrication		X	X	X
(7) Recipient spends less than 80 percent of proposed pre-production costs prior to start of production		X	X	X
(8) Amount of relief volume is produced		X	X	X

§ 203.5 What is BSEE's authority to collect information?

(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.*, and assigned OMB Control Number 1014–0005. The title of this information collection is ''30 CFR part 203, Relief or Reduction in Royalty Rates.''

(b) BSEE collects this information to make decisions on the economic viability of leases requesting a suspension or elimination of royalty or net profit share. Responses are required to obtain

a benefit or are mandatory according to 43 U.S.C. 1331 *et seq*. BSEE will protect information considered proprietary under applicable law and under regulations at § 203.61, ''How do I assess my chances for getting relief?'' and 30 CFR 250.197, ''Data and information to be made available to the public or for limited inspection.''

(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, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36148, June 6, 2016]

Subpart B—OCS Oil, Gas, and Sulfur General

ROYALTY RELIEF FOR DRILLING ULTRA-DEEP WELLS ON LEASES NOT SUBJECT TO DEEP WATER ROYALTY RELIEF

§ 203.30 Which leases are eligible for royalty relief as a result of drilling a phase 2 or phase 3 ultra-deep well?

Your lease may receive a royalty suspension volume (RSV) under §§ 203.31 through 203.36 if the lease meets all the requirements of this section.

(a) The lease is located in the GOM wholly west of 87 degrees, 30 minutes West longitude in water depths entirely less than 400 meters deep.

(b) The lease has not produced gas or oil from a deep well or an ultra-deep well, except as provided in § 203.31(b).

(c) If the lease is located entirely in more than 200 meters and entirely less than 400 meters of water, it must either:

(1) Have been issued before November 28, 1995, and not been granted deep water royalty relief under 43 U.S.C. 1337(a)(3)(C), added by section 302 of the Deep Water Royalty Relief Act; or

(2) Have been issued after November 28, 2000, and not been granted deep water royalty relief under §§ 203.60 through 203.79.

§ 203.31 If I have a qualified phase 2 or qualified phase 3 ultra-deep well, what royalty relief would that well earn for my lease?

(a) Subject to the administrative requirements of § 203.35 and the price conditions in § 203.36, your qualified well earns your lease an RSV shown in the following table in billions of cubic feet (BCF) or in thousands of cubic feet (MCF) as prescribed in § 203.33:

If you have a qualified phase 2 or qualified phase 3 ultra-deep well that is:	Then your lease earns an RSV on this volume of gas production:
(1) An original well,	35 BCF.
(2) A sidetrack with a sidetrack measured depth of at least 20,000 feet,	35 BCF.
(3) An ultra-deep short sidetrack that is a phase 2 ultra-deep well,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.
(4) An ultra-deep short sidetrack that is a phase 3 ultra-deep well,	0 BCF.

(b)(1) This paragraph applies if your lease:

(i) Has produced gas or oil from a deep well with a perforated interval the top of which is less than 18,000 feet TVD SS;

(ii) Was issued in a lease sale held between January 1, 2004, and December 31, 2005; and

(iii) The terms of your lease expressly incorporate the provisions of §§ 203.41 through 203.47 as they existed at the time the lease was issued.

(2) Subject to the administrative requirements of § 203.35 and the price conditions in § 203.36, your qualified well earns your lease an RSV shown in the

following table in BCF or MCF as prescribed in § 203.33:

If you have a qualified phase 2 ultra-deep well that is . . .	Then your lease earns an RSV on this volume of gas production:
(i) An original well or a sidetrack with a sidetrack measured depth of at least 20,000 feet TVD SS,	10 BCF.
(ii) An ultra-deep short sidetrack,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 10 BCF.

(c) Lessees may request a refund of or recoup royalties paid on production from qualified phase 2 or phase 3 ultra-deep wells that:

(1) Occurs before December 18, 2008, and

(2) Is subject to application of an RSV under either § 203.31 or § 203.41.

(d) The following examples illustrate how this section applies. These examples assume that your lease is located in the GOM west of 87 degrees, 30 minutes West longitude and in water less than 400 meters deep (see § 203.30(a)), has no existing deep or ultra-deep wells and that the price thresholds prescribed in § 203.36 have not been exceeded.

Example 1: In 2008, you drill and begin producing from an ultra-deep well with a perforated interval the top of which is 25,000 feet TVD SS, and your lease has had no prior production from a deep or ultra-deep well. Assuming your lease has no deepwater royalty relief (see § 203.30(c)), your lease is eligible (according to § 203.30(b)) to earn an RSV under § 203.31 because it has not yet produced from a deep well. Your lease earns an RSV of 35 BCF under this section when this well begins producing. According to § 203.31(a), your 25,000 foot well qualifies your lease for this RSV because the well was drilled after the relief authorized here became effective (when the proposed version of this rule was published on May 18, 2007) and produced from an interval that meets the criteria for an ultra-deep well (*i.e.*, is a phase 2 ultra-deep well as defined in § 203.0). Then in 2014, you drill and produce from another ultra-deep well with a perforated interval the top of which is 29,000 feet TVD SS. Your lease earns no additional RSV under this section when this second ultra-deep well produces, because your lease no longer meets the condition in (§ 203.30(b)) of no production from a deep well. However, any remaining RSV earned by the first ultra-deep well on your lease would be applied to production from both the first and the second ultra-deep wells as prescribed in § 203.33(a)(2), or § 203.33(b)(2) if your lease is part of a unit.

Example 2: In 2005, you spudded and began producing from an ultra-deep well with a perforated interval the top of which is 23,000 feet TVD SS. Your lease earns no RSV under this section from this phase 1 ultra-deep well (as defined in § 203.0) because you spudded the well before the publication date (May 18, 2007) of the proposed rule when royalty relief under § 203.31(a) became effective. However, this ultra-deep well may earn an RSV of 25 BCF for your lease under § 203.41 (that became effective May 3, 2004), if the lease is located in water depths partly or entirely less than 200 meters and has not previously produced from a deep well (§ 203.30(b)).

Example 3: In 2000, you began producing from a deep well with a perforated interval the top of which is 16,000 feet TVD SS and your lease is located in water 100 meters deep. Then in 2008, you drill and produce from a new ultra-deep well with a perforated interval the top of which is 24,000 feet TVD SS. Your lease earns no RSV under either this section or § 203.41 because the 16,000-foot well was drilled before we offered any way to earn an RSV for producing from a deep well (see dates in the definition of qualified well in § 203.0) and because the existence of the 16,000-foot well means the lease is not eligible (see § 203.30(b)) to earn an RSV for the 24,000-foot well. Because the lease existed in the year 2000, it cannot be eligible for the exception to this eligibility condition provided in § 203.31(b).

Example 4: In 2008, you spud and produce from an ultra-deep well with a perforated interval the top of which is 22,000 feet TVD SS, your lease is located in water 300 meters deep, and your lease has had no previous production from a deep or ultra-deep well. Your lease earns an RSV of 35 BCF under this section when this well begins producing because your lease meets the conditions in § 203.30 and the well fits the definition of a phase 2 ultra-deep well (in § 203.0). Then in 2010, you spud and produce from a deep well with a perforated interval the top of which is 16,000 feet TVD SS. Your 16,000-foot well earns no RSV because it is on a lease that already has a producing well at least 18,000 feet subsea (see § 203.42(a)), but any remaining RSV earned by the ultra-deep well would also be applied to production from the deep well as prescribed in § 203.33(a)(2), or § 203.33(b)(2) if your lease is part of a unit and § 203.43(a)(2),

or § 203.43(b)(2) if your lease is part of a unit. However, if the 16,000-foot deep well does not begin production until 2016 (or if your lease were located in water less than 200 meters deep), then the 16,000-foot well would not be a qualified deep well because this well does not begin production within the interval specified in the definition of a qualified well in § 203.0, and the RSV earned by the ultra-deep well would not be applied to production from this (unqualified) deep well.

Example 5: In 2008, you spud a deep well with a perforated interval the top of which is 17,000 feet TVD SS that becomes a qualified well and earns an RSV of 15 BCF under § 203.41 when it begins producing. Then in 2011, you spud an ultra-deep well with a perforated interval the top of which is 26,000 feet TVD SS. Your 26,000-foot well becomes a qualified ultra-deep well because it meets the date and depth conditions in this definition under § 203.0 when it begins producing, but your lease earns no additional RSV under this section or § 203.41 because it is on a lease that already has production from a deep well (see § 203.30(b)). Both the qualified deep well and the qualified ultra-deep well would share your lease's total RSV of 15 BCF in the manner prescribed in §§ 203.33 and 203.43.

Example 6: In 2008, you spud a qualified ultra-deep well that is a sidetrack with a sidetrack measured depth of 21,000 feet and a perforated interval the top of which is 25,000 feet TVD SS. This well meets the definition of an ultra-deep well but is too long to be classified an ultra-deep short sidetrack in § 203.0. If your lease is located in 150 meters of water and has not previously produced from a deep well, your lease earns an RSV of 35 BCF because it was drilled after the effective date for earning this RSV. Further, this RSV applies to gas production from this and any future qualified deep and qualified ultra-deep wells on your lease, as prescribed in § 203.33. The absence of an expiration date for earning an RSV on an ultra-deep well means this long sidetrack well becomes a qualified well whenever it starts production. If your sidetrack has a sidetrack measured depth of 14,000 feet and begins production in March 2009, it earns an RSV of 12.4 BCF under this section because it meets the definitions of a phase 2 ultra-deep well (production begins before the expiration date for the pre-existing relief in its water depth category) and an ultra-deep short sidetrack in § 203.0. However, if it does not begin production until 2010, it earns no RSV because it is too short as a phase 3 ultra-deep well to be a qualified ultra-deep well.

Example 7: Your lease was issued in June 2004 and expressly incorporates the provisions of §§ 203.41 through 203.47 as they existed at that time. In January 2005, you spud a deep well (well no. 1) with a perforated interval the top of which is 16,800 feet TVD SS that becomes a qualified well and earns an RSV of 15 BCF under § 203.41 when it begins producing. Then in February 2008, you spud an ultra-deep well (well no. 2) with a perforated interval the top of which is 22,300 feet that begins producing in November 2008, after well no. 1 has started production. Well no. 2 earns your lease an additional RSV of 10 BCF under paragraph (b) of this section because it begins production in time to be classified as a phase 2 ultra-deep well. If, on the other hand, well no. 2 had begun producing in June 2009, it would earn no additional RSV for the lease because it would be classified as a phase 3 ultra-deep well and thus is not entitled to the exception under paragraph (b) of this section.

§ 203.32 What other requirements or restrictions apply to royalty relief for a qualified phase 2 or phase 3 ultra-deep well?

(a) If a qualified ultra-deep well on your lease is within a unitized portion of your lease, the RSV earned by that well under this section applies only to your lease and not to other leases within the unit or to the unit as a whole.

(b) If your qualified ultra-deep well is a directional well (either an original well or a sidetrack) drilled across a lease line, then either:

(1) The lease with the perforated interval that initially produces earns the RSV or

(2) If the perforated interval crosses a lease line, the lease where the surface of the well is located earns the RSV.

(c) Any RSV earned under § 203.31 is in addition to any royalty suspension supplement (RSS) for your lease under § 203.45 that results from a different wellbore.

(d) If your lease earns an RSV under § 203.31 and later produces from a deep well that is not a qualified well, the RSV is not forfeited or terminated, but you may not apply the RSV earned under § 203.31 to production from the non-qualified well.

(e) You owe minimum royalties or rentals in accordance with your lease terms notwithstanding any RSVs allowed under paragraphs (a) and (b) of § 203.31.

(f) Unused RSVs transfer to a successor lessee and expire with the lease.

§ 203.33 To which production do I apply the RSV earned by qualified phase 2 and phase 3 ultra-deep wells on my lease or in my unit?

(a) You must apply the RSV allowed in § 203.31(a) and (b) to gas volumes produced from qualified wells on or after May 18, 2007, reported on the Oil and Gas Operations Report, Part A (OGOR–A) for your lease under 30 CFR 1210.102. All gas production from qualified wells reported on the OGOR–A, including production not subject to royalty, counts toward the total lease RSV earned by both deep or ultra-deep wells on the lease.

(b) This paragraph applies to any lease with a qualified phase 2 or phase 3 ultra-deep well that is not within a BSEE-approved unit. Subject to the price conditions of § 203.36, you must apply the RSV prescribed in § 203.31 as required under the following paragraphs (b)(1) and (b)(2) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of May 18, 2007, or the date the first qualified phase 2 or phase 3 ultra-deep well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production from qualified wells on your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44.

(c) This paragraph applies to any lease with a qualified phase 2 or phase 3 ultra-deep well where all or part of the lease is within a BSEE-approved unit. Under the unit agreement, a share of the production from all the qualified wells in the unit participating area would be allocated to your lease each month according to the participating area percentages. Subject to the price conditions of § 203.36, you must apply the RSV prescribed in § 203.31 as follows:

(1) You must apply the RSV to the earliest gas production occurring on and after the later of May 18, 2007, or the date that the first qualified phase 2 or phase 3 ultra-deep well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production:

(i) From qualified wells on the non-unitized area of your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44; and

(ii) Allocated to your lease under a BSEE-approved unit agreement from qualified wells on unitized areas of your lease and on other leases in participating areas of the unit, regardless of their depth, for which the requirements in § 203.35 or § 203.44 have been met. The allocated share under paragraph (a)(2)(ii) of this section does not increase the RSV for your lease.

Example: The east half of your lease A is unitized with all of lease B. There is one qualified phase 2 ultra-deep well on the non-unitized portion of lease A that earns lease A an RSV of 35 BCF under § 203.31, one qualified deep well on the unitized portion of lease A (drilled after the ultra-deep well on the non-unitized portion of that lease) and a qualified phase 2 ultra-deep well on lease B that earns lease B a 35 BCF RSV under § 203.31. The participating area percentages allocate 40 percent of production from both of the unit qualified wells to lease A and 60 percent to lease B. If the non-unitized qualified phase 2 ultra-deep well on lease A produces 12 BCF, and the unitized qualified well on lease A produces 18 BCF, and the qualified well on lease B produces 37 BCF, then the production volume from and allocated to lease A to which the lease A RSV applies is 34 BCF [12 + (18 + 37)(0.40)]. The production volume allocated to lease B to which the lease B RSV applies is 33 BCF [(18 + 37)(0.60)]. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

(d) You must begin paying royalties when the cumulative production of gas from all qualified wells on your lease, or allocated to your lease under paragraph (b) of this section, reaches the applicable RSV allowed under § 203.31 or § 203.41. For the month in which cumulative production reaches this RSV, you owe royalties on the portion of gas production from or allocated to your lease that exceeds the RSV remaining at the beginning of that month.

§ 203.34 To which production may an RSV earned by qualified phase 2 and phase 3 ultra-deep wells on my lease not be applied?

You may not apply an RSV earned under § 203.31:

(a) To production from completions less than 15,000 feet TVD SS, except in cases where the qualified well is re-perforated in the same reservoir previously perforated deeper than 15,000 feet TVD SS;

(b) To production from a deep well or ultra-deep well on any other lease, except as provided in paragraph (c) of § 203.33;

(c) To any liquid hydrocarbon (oil and condensate) volumes; or

(d) To production from a deep well or ultra-deep well that commenced drilling before:

(1) March 26, 2003, on a lease that is located entirely or partly in water less than 200 meters deep; or

(2) May 18, 2007, on a lease that is located entirely in water more than 200 meters deep.

§ 203.35 What administrative steps must I take to use the RSV earned by a qualified phase 2 or phase 3 ultra-deep well?

To use an RSV earned under § 203.31:

(a) You must notify the BSEE Regional Supervisor for Production and Development in writing of your intent to begin drilling operations on all your ultra-deep wells.

(b) Before beginning production, you must meet any production measurement requirements that the BSEE Regional Supervisor for Production and Development has determined are necessary under 30 CFR part 250, subpart L.

(c)(1) Within 30 days of the beginning of production from any wells that would become qualified phase 2 or phase 3 ultra-deep wells by satisfying the requirements of this section:

(i) Provide written notification to the BSEE Regional Supervisor for Production and Development that production has begun; and

(ii) Request confirmation of the size of the RSV earned by your lease.

(2) If you produced from a qualified phase 2 or phase 3 ultra-deep well before December 18, 2008, you must provide the information in paragraph (c)(1) of this section no later than January 20, 2009.

(d) If you cannot produce from a well that otherwise meets the criteria for a qualified phase 2 ultra-deep well that is an ultra-deep short sidetrack before May 3, 2009, on a lease that is located entirely or partly in water less than 200 meters deep, or before May 3, 2013, on a lease that is located entirely in water more than 200 meters but less than 400 meters deep, the BSEE Regional Supervisor for Production and Development may extend the deadline for beginning production for up to 1 year, based on the circumstances of the particular well involved, if it meets all the following criteria.

(1) The delay occurred after drilling reached the total depth in your well.

(2) Production (other than test production) was expected to begin from the well before May 3, 2009, on a lease that is located entirely or partly in water less than 200 meters deep or before May 3, 2013, on a lease that is located entirely in water more than 200 meters but less than 400 meters deep. You must provide a credible activity schedule with supporting documentation.

(3) The delay in beginning production is for reasons beyond your control, such as adverse weather and accidents which BSEE deems were unavoidable.

§ 203.36 Do I keep royalty relief if prices rise significantly?

(a) You must pay the Office of Natural Resources Revenue royalties on all gas production to which an RSV otherwise would be applied under § 203.33 for any calendar year in which the average daily closing New York Mercantile Exchange (NYMEX) natural gas price exceeds the applicable threshold price shown in the following table.

A price threshold in year 2007 dollars of . . .	Applies to . . .
(1) $10.15 per MMBtu,	(i) The first 25 BCF of RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease that is located in water partly or entirely less than 200 meters deep issued before December 18, 2008; and (ii) Any RSV earned under § 203.31(b) by a phase 2 ultra-deep well.

A price threshold in year 2007 dollars of . . .	Applies to . . .
(2) $4.55 per MMBtu,	(i) Any RSV earned under § 203.31(a) by a phase 3 ultra-deep well unless the lease terms prescribe a different price threshold; (ii) The last 10 BCF of the 35 BCF of RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease that is located in water partly or entirely less than 200 meters deep issued before December 18, 2008, and that is not a non-converted lease; (iii) The last 15 BCF of the 35 BCF of RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a non-converted lease; (iv) Any RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease in water partly or entirely less than 200 meters deep issued on or after December 18, 2008, unless the lease terms prescribe a different price threshold; and (v) Any RSV earned under § 203.31(a) by a phase 2 ultra-deep well on a lease in water entirely more than 200 meters deep and entirely less than 400 meters deep.
(3) $4.08 per MMBtu,	(i) The first 20 BCF of RSV earned by a well that is located on a non-converted lease issued in OCS Lease Sale 178.
(4) $5.83 per MMBtu,	(i) The first 20 BCF of RSV earned by a well that is located on a non-converted lease issued in OCS Lease Sales 180, 182, 184, 185, or 187.

(b) For purposes of paragraph (a) of this section, determine the threshold price for any calendar year after 2007 by:

(1) Determining the percentage of change during the year in the Department of Commerce's implicit price deflator for the gross domestic product; and

(2) Adjusting the threshold price for the previous year by that percentage.

(c) The following examples illustrate how this section applies.

Example 1: Assume that a lessee drills and begins producing from a qualified phase 2 ultra-deep well in 2008 on a lease issued in 2004 in less than 200 meters of water that earns the lease an RSV of 35 BCF. Further, assume the well produces a total of 18 BCF by the end of 2009 and in both of those years, the average daily NYMEX closing natural gas price is less than $10.15 (adjusted for inflation after 2007). The lessee does not pay royalty on the 18 BCF because the gas price threshold under paragraph (a)(1) of this section applies to the first 25 BCF of this RSV earned by this phase 2 ultra-deep well. In 2010, the well produces another 13 BCF. In that year, the average daily closing NYMEX natural gas price is greater than $4.55 per MMBtu (adjusted for inflation after 2007), but less than $10.15 per MMBtu (adjusted for inflation after 2007). The first 7 BCF produced in 2010 will exhaust the first 25 BCF (that is subject to the $10.15 threshold) of the 35 BCF RSV that the well earned. The lessee must pay royalty on the remaining 6 BCF produced in 2010, because it is subject to the $4.55 per MMBtu threshold under paragraph (a)(2)(ii) of this section which was exceeded.

Example 2: Assume that a lessee:

(1) Drills and produces from well no.1, a qualified deep well in 2008 to a depth of 15,500 feet TVD SS that earns a 15 BCF RSV for the lease under § 203.41, which would be subject to a price threshold of $10.15 per MMBtu (adjusted for inflation after 2007), meaning the lease is partly or entirely in less than 200 meters of water;

(2) Later in 2008, drills and produces from well no. 2, a second qualified deep well to a depth of 17,000 feet TVD SS that earns no additional RSV (see § 203.41(c)(1)); and

(3) In 2015, drills and produces from well no. 3, a qualified phase 3 ultra-deep well that earns no additional RSV since the lease already has an RSV established by prior deep well production. Further assume that in 2015, the average daily closing NYMEX natural gas price exceeds $4.55 per MMBtu (adjusted for inflation after 2007) but does not exceed $10.15 per MMBtu (adjusted for inflation after 2007). In 2015, any remaining RSV earned by well no. 1 (which would have been applied to production from well nos. 1 and 2 in the intervening years), would be applied to production from all three qualified wells. Because the price threshold applicable to that RSV was not exceeded, the production from all three qualified wells would be royalty-free until the 15 BCF RSV earned by well no. 1 is exhausted.

Example 3: Assume the same initial facts regarding the three wells as in Example 2. Further assume that well no. 1 stopped producing in 2011 after it had produced 8 BCF, and that well no. 2 stopped producing in 2012 after it had produced 5 BCF. Two BCF of the RSV earned by well no. 1 remain. That RSV would be applied to production from well no.

3 until it is exhausted, and the lessee therefore would not pay royalty on those 2 BCF produced in 2015, because the $10.15 per MMBtu (adjusted for inflation after 2007) price threshold is not exceeded. The determination of which price threshold applies to deep gas production depends on when the first qualified well earned the RSV for the lease, not on which wells use the RSV.

Example 4: Assume that in February 2010, a lessee completes and begins producing from an ultra-deep well (at a depth of 21,500 feet TVD SS) on a lease located in 325 meters of water with no prior production from any deep well and no deep water royalty relief. The ultra-deep well would be a phase 2 ultra-deep well (see definition in § 203.0), and would earn the lease an RSV of 35 BCF under §§ 203.30 and 203.31. Further assume that the average daily closing NYMEX natural gas price exceeds $4.55 per MMBtu (adjusted for inflation after 2007) but does not exceed $10.15 per MMBtu (adjusted for inflation after 2007) during 2010. Because the lease is located in more than 200 but less than 400 meters of water, the $4.55 per MMBtu price threshold applies to the whole RSV (see paragraph (a)(2)(v) of this section), and the lessee will owe royalty on all gas produced from the ultra-deep well in 2010.

(d) You must pay any royalty due under this section no later than March 31 of the year following the calendar year for which you owe royalty. If you do not pay by that date, you must pay late payment interest under 30 CFR 1218.54 from April 1 until the date of payment.

(e) Production volumes on which you must pay royalty under this section count as part of your RSV.

ROYALTY RELIEF FOR DRILLING DEEP GAS WELLS ON LEASES NOT SUBJECT TO DEEP WATER ROYALTY RELIEF

§ 203.40 Which leases are eligible for royalty relief as a result of drilling a deep well or a phase 1 ultra-deep well?

Your lease may receive an RSV under §§ 203.41 through 203.44, and may receive an RSS under §§ 203.45 through 203.47, if it meets all the requirements of this section.

(a) The lease is located in the GOM wholly west of 87 degrees, 30 minutes West longitude in water depths entirely less than 400 meters deep.

(b) The lease has not produced gas or oil from a well with a perforated interval the top of which is 18,000 feet TVD SS or deeper that commenced drilling either:

(1) Before March 26, 2003, on a lease that is located partly or entirely in water less than 200 meters deep; or

(2) Before May 18, 2007, on a lease that is located in water entirely more than 200 meters and entirely less than 400 meters deep.

(c) In the case of a lease located partly or entirely in water less than 200 meters deep, the lease was issued in a lease sale held either:

(1) Before January 1, 2001;

(2) On or after January 1, 2001, and before January 1, 2004, and, in cases where the original lease terms provided for an RSV for deep gas production, the lessee has exercised the option provided for in § 203.49; or

(3) On or after January 1, 2004, and the lease terms provide for royalty relief under §§ 203.41 through 203.47. (Note: Because the original § 203.41 has been divided into new §§ 203.41 and 203.42 and subsequent sections have been redesignated as §§ 203.43 through 203.48, royalty relief in lease terms for leases issued on or after January 1, 2004, should be read as referring to §§ 203.41 through 203.48.)

(d) If the lease is located entirely in more than 200 meters and less than 400 meters of water, it must either:

(1) Have been issued before November 28, 1995, and not been granted deep water royalty relief under 43 U.S.C. 1337(a)(3)(C), added by section 302 of the Deep Water Royalty Relief Act; or

(2) Have been issued after November 28, 2000, and not been granted deep water royalty relief under §§ 203.60 through 203.79.

§ 203.41 If I have a qualified deep well or a qualified phase 1 ultra-deep well, what royalty relief would my lease earn?

(a) To qualify for a suspension volume under paragraphs (b) or (c) of this section, your lease must meet the requirements in § 203.40 and the requirements in the following table.

If your lease has not . . .	And if it later . . .	Then your lease . . .
(1) produced gas or oil from any deep well or ultra-deep well,	Has a qualified deep well or qualified phase 1 ultra-deep well,	earns an RSV specified in paragraph (b) of this section.
(2) produced gas or oil from a well with a perforated interval whose top is 18,000 feet TVD SS or deeper,	Has a qualified deep well with a perforated interval whose top is 18,000 feet TVD SS or deeper or a qualified phase 1 ultra-deep well,	earns an RSV specified in paragraph (c) of this section.

(b) If your lease meets the requirements in paragraph (a)(1) of this section, it earns the RSV prescribed in the following table:

If you have a qualified deep well or a qualified phase 1 ultra-deep well that is:	Then your lease earns an RSV on this volume of gas production:
(1) An original well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	15 BCF.
(2) A sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 15 BCF.
(3) An original well with a perforated interval the top of which is at least 18,000 feet TVD SS,	25 BCF.
(4) A sidetrack with a perforated interval the top of which is at least 18,000 feet TVD SS,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 25 BCF.

(c) If your lease meets the requirements in paragraph (a)(2) of this section, it earns the RSV prescribed in the following table. The RSV specified in this paragraph is in addition to any RSV your lease already may have earned from a qualified deep well with a perforated interval whose top is from 15,000 feet to less than 18,000 feet TVD SS.

If you have a qualified deep well or a qualified phase 1 ultra-deep well that is . . .	Then you earn an RSV on this amount of gas production:
(1) An original well or a sidetrack with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	0 BCF.
(2) An original well with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	10 BCF.
(3) A sidetrack with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	4 BCF plus 600 MCF times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 10 BCF.

(d) Lessees may request a refund of or recoup royalties paid on production from qualified wells on a lease that is located in water entirely deeper than 200 meters but entirely less than 400 meters deep that:

(1) Occurs before December 18, 2008; and

(2) Is subject to application of an RSV under either § 203.31 or § 203.41.

(e) The following examples illustrate how this section applies, assuming your lease meets the location, prior production, and lease issuance conditions in § 203.40 and paragraph (a) of this section:

Example 1: If you have a qualified deep well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, your lease earns an RSV of 15 BCF under paragraph (b)(1) of this section. This RSV must be applied to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48. However, if the top of the perforated interval is 18,500 feet TVD SS, the RSV is 25 BCF according to paragraph (b)(3) of this section.

Example 2: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 6,789 feet, we round the measured depth to 6,800 feet and your lease earns an RSV of 8.08 BCF under paragraph (b)(2) of this section. This RSV would be applied to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48.

Example 3: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 19,500 feet, your lease earns an RSV of 15 BCF. This RSV would be applied to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48, even though 4 BCF plus 600 MCF per foot of sidetrack measured

depth equals 15.7 BCF because paragraph (b)(2) of this section limits the RSV for a sidetrack at the amount an original well to the same depth would earn.

Example 4: If you have drilled and produced a deep well with a perforated interval the top of which is 16,000 feet TVD SS before March 26, 2003 (and the well therefore is not a qualified well and has earned no RSV under this section), and later drill:

(i) A deep well with a perforated interval the top of which is 17,000 feet TVD SS, your lease earns no RSV (see paragraph (c)(1) of this section);

(ii) A qualified deep well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, your lease earns an RSV of 10 BCF under paragraph (c)(2) of this section. This RSV would be applied to gas production from qualified wells on your lease, as prescribed in §§ 203.43 and 203.48; or

(iii) A qualified deep well that is a sidetrack with a perforated interval the top of which is 19,000 feet TVD SS, that has a sidetrack measured depth of 7,000 feet, your lease earns an RSV of 8.2 BCF under paragraph (c)(3) of this section. This RSV would be applied to gas production from qualified wells on your lease, as prescribed in §§ 203.43 and 203.48.

Example 5: If you have a qualified deep well that is an original well with a perforated interval the top of which is 16,000 feet TVD SS, and later drill a second qualified well that is an original well with a perforated interval the top of which is 19,000 feet TVD SS, we increase the total RSV for your lease from 15 BCF to 25 BCF under paragraph (c)(2) of this section. We will apply that RSV to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48. If the second well has a perforated interval the top of which is 22,000 feet TVD SS (instead of 19,000 feet), the total RSV for your lease would increase to 25 BCF only in 2 situations: (1) If the second well was a phase 1 ultra-deep well, *i.e.,* if drilling began before May 18, 2007, or (2) the exception in § 203.31(b) applies. In both situations, your lease must be partly or entirely in less than 200 meters of water and production must begin on this well before May 3, 2009. If drilling of the second well began on or after May 18, 2007, the second well would be qualified as a phase 2 or phase 3 ultra-deep well and, unless the exception in § 203.31(b) applies, would not earn any additional RSV (as prescribed in § 203.30), so the total RSV for your lease would remain at 15 BCF.

Example 6: If you have a qualified deep well that is a sidetrack, with a perforated interval the top of which is 16,000 feet TVD SS and a sidetrack measured depth of 4,000 feet, and later drill a second qualified well that is a sidetrack, with a perforated interval the top of which is 19,000 feet TVD SS and a sidetrack measured depth of 8,000 feet, we increase the total RSV for your lease from 6.4 BCF [4 + (600 * 4,000)/1,000,000] to 15.2 BCF {6.4 + [4 + (600 * 8,000)/1,000,000)]} under paragraphs (b)(2) and (c)(3) of this section. We would apply that RSV to gas production from all qualified wells on your lease, as prescribed in §§ 203.43 and 203.48. The difference of 8.8 BCF represents the RSV earned by the second sidetrack that has a perforated interval the top of which is deeper than 18,000 feet TVD SS.

§ 203.42 What conditions and limitations apply to royalty relief for deep wells and phase 1 ultra-deep wells?

The conditions and limitations in the following table apply to royalty relief under § 203.41.

If . . .	Then . . .
(a) Your lease has produced gas or oil from a well with a perforated interval the top of which is 18,000 feet TVD SS or deeper,	your lease cannot earn an RSV under § 203.41 as a result of drilling any subsequent deep wells or phase 1 ultra-deep wells.
(b) You determine RSV under § 203.41 for the first qualified deep well or qualified phase 1 ultra-deep well on your lease (whether an original well or a sidetrack) because you drilled and produced it within the time intervals set forth in the definitions for qualified wells,	that determination establishes the total RSV available for that drilling depth interval on your lease (*i.e.,* either 15,000–18,000 feet TVD SS, or 18,000 feet TVD SS and deeper), regardless of the number of subsequent qualified wells you drill to that depth interval.
(c) A qualified deep well or qualified phase 1 ultra-deep well on your lease is within a unitized portion of your lease,	the RSV earned by that well under § 203.41 applies only to production from qualified wells on or allocated to your lease and not to other leases within the unit.
(d) Your qualified deep well or qualified phase 1 ultra-deep well is a directional well (either an original well or a sidetrack) drilled across a lease line,	the lease with the perforated interval that initially produces earns the RSV. However, if the perforated interval crosses a lease line, the lease where the surface of the well is located earns the RSV.
(e) You earn an RSV under § 203.41,	that RSV is in addition to any RSS for your lease under § 203.45 that results from a different wellbore.
(f) Your lease earns an RSV under § 203.41 and later produces from a well that is not a qualified well,	the RSV is not forfeited or terminated, but you may not apply the RSV under § 203.41 to production from the non-qualified well.
(g) You qualify for an RSV under paragraphs (b) or (c) of § 203.41,	you still owe minimum royalties or rentals in accordance with your lease terms.

If . . .	Then . . .
(h) You transfer your lease,	unused RSVs transfer to a successor lessee and expire with the lease.

Example to paragraph (b): If your first qualified deep well is a sidetrack with a perforated interval whose top is 16,000 feet TVD SS and earns an RSV of 12.5 BCF, and you later drill a qualified original deep well to 17,000 feet TVD SS, the RSV for your lease remains at 12.5 BCF and does not increase to 15 BCF. However, under paragraph (c) of § 203.41, if you subsequently drill a qualified deep well to a depth of 18,000 feet or greater TVD SS, you may earn an additional RSV.

§ 203.43 To which production do I apply the RSV earned from qualified deep wells or qualified phase 1 ultra-deep wells on my lease?

(a) You must apply the RSV prescribed in § 203.41(b) and (c) to gas volumes produced from qualified wells on or after May 3, 2004, reported on the OGOR–A for your lease under 30 CFR 1210.102, as and to the extent prescribed in §§ 203.43 and 203.48.

(1) Except as provided in paragraph (a)(2) of this section, all gas production from qualified wells reported on the OGOR–A, including production that is not subject to royalty, counts toward the lease RSV.

(2) Production to which an RSS applies under §§ 203.45 and 203.46 does not count toward the lease RSV.

(b) This paragraph applies to any lease with a qualified deep well or qualified phase 1 ultra-deep well when no part of the lease is within a BSEE-approved unit. Subject to the price conditions in § 203.48, you must apply the RSV prescribed in § 203.41 as required under the following paragraphs (b)(1) and (b)(2) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of:

(i) May 3, 2004, for an RSV earned by a qualified deep well or qualified phase 1 ultra-deep well on a lease that is located entirely or partly in water less than 200 meters deep;

(ii) May 18, 2007, for an RSV earned by a qualified deep well on a lease that is located entirely in water more than 200 meters deep; or

(iii) The date that the first qualified well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production from qualified wells on your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44.

Example 1: On a lease in water less than 200 meters deep, you began drilling an original deep well with a perforated interval the top of which is 18,200 feet TVD SS in September 2003, that became a qualified deep well in July 2004, when it began producing and using the RSV that it earned. You subsequently drill another original deep well with a perforated interval the top of which is 16,600 feet TVD SS, which becomes a qualified deep well when production begins in August 2008. The first well earned an RSV of 25 BCF (see § 203.41(a)(1) and (b)(3)). You must apply any remaining RSV each month beginning in August 2008 to production from both wells until the 25 BCF RSV is fully utilized according to paragraph (b)(2) of this section. If the second well had begun production in August 2009, it would not be a qualified deep well because it started production after expiration in May 2009 of the ability to qualify for royalty relief in this water depth, and could not share any of the remaining RSV (see definition of a qualified deep well in § 203.0).

Example 2: On a lease in water between 200 and 400 meters deep, you begin drilling an original deep well with a perforated interval the top of which is 17,100 feet TVD SS in November 2010 that becomes a qualified deep well in June 2011 when it begins producing and using the RSV. You subsequently drill another original deep well with a perforated interval the top of which is 15,300 feet TVD SS which becomes a qualified deep well by beginning production in October 2011 (see definition of a qualified deep well in § 203.0). Only the first well earns an RSV equal to 15 BCF (see § 203.41(a) and (b)). You must apply any remaining RSV each month beginning in October 2011 to production from both qualified deep wells until the 15 BCF RSV is fully utilized according to paragraph (b)(2) of this section.

(c) This paragraph applies to any lease with a qualified deep well or qualified phase 1 ultra-deep well when all or part of the lease is within a BSEE-approved unit. Under the unit agreement, a share of the production from all the qualified wells in the unit

participating area would be allocated to your lease each month according to the participating area percentages. Subject to the price conditions in § 203.48, you must apply the RSV prescribed under § 203.41 as required under the following paragraphs (c)(1) through (3) of this section.

(1) You must apply the RSV to the earliest gas production occurring on and after the later of:

(i) May 3, 2004, for an RSV earned by a qualified well or qualified phase 1 ultra-deep well on a lease that is located entirely or partly in water less than 200 meters deep;

(ii) May 18, 2007, for an RSV earned by a qualified deep well on a lease that is located entirely in water more than 200 meters deep; or

(iii) The date that the first qualified well that earns your lease the RSV begins production (other than test production).

(2) You must apply the RSV to only gas production:

(i) From all qualified wells on the non-unitized area of your lease, regardless of their depth, for which you have met the requirements in § 203.35 or § 203.44; and,

(ii) Allocated to your lease under a BSEE-approved unit agreement from qualified wells on unitized areas of your lease and on unitized areas of other leases in the unit, regardless of their depth, for which the requirements in § 203.35 or § 203.44 have been met.

(3) The allocated share under paragraph (c)(2)(ii) of this section does not increase the RSV for your lease. None of the volumes produced from a well that is not within a unit participating area may be allocated to other leases in the unit.

Example: The east half of your lease A is unitized with all of lease B. There is one qualified 19,000-foot TVD SS deep well on the non-unitized portion of lease A, one qualified 18,500-foot TVD SS deep well on the unitized portion of lease A, and a qualified 19,400-foot TVD SS deep well on lease B. The participating area percentages allocate 32 percent of production from both of the unit qualified deep wells to lease A and 68 percent to lease B. If the non-unitized qualified deep well on lease A produces 12 BCF and the unitized qualified deep well on lease A produces 15 BCF, and the qualified deep well on lease B produces 10 BCF, then the production volume from and allocated to lease A to which the lease an RSV applies is 20 BCF [12 + (15 + 10) * (0.32)]. The production volume allocated to lease B to which the lease B RSV applies is 17 BCF [(15 + 10) * (0.68)].

(d) You must begin paying royalties when the cumulative production of gas from all qualified wells on your lease, or allocated to your lease under paragraph (c) of this section, reaches the applicable RSV allowed under § 203.31 or § 203.41. For the month in which cumulative production reaches this RSV, you owe royalties on the portion of gas production that exceeds the RSV remaining at the beginning of that month.

(e) You may not apply the RSV allowed under § 203.41 to:

(1) Production from completions less than 15,000 feet TVD SS, except in cases where the qualified deep well is re-perforated in the same reservoir previously perforated deeper than 15,000 feet TVD SS;

(2) Production from a deep well or phase 1 ultra-deep well on any other lease, except as provided in paragraph (c) of this section;

(3) Any liquid hydrocarbon (oil and condensate) volumes; or

(4) Production from a deep well or phase 1 ultra-deep well that commenced drilling before:

(i) March 26, 2003, on a lease that is located entirely or partly in water less than 200 meters deep, or

(ii) May 18, 2007, on a lease that is located entirely in water more than 200 meters deep.

§ 203.44 What administrative steps must I take to use the royalty suspension volume?

(a) You must notify the BSEE Regional Supervisor for Production and Development in writing of your intent to begin drilling operations on all deep wells and phase 1 ultra-deep wells; and

(b) Within 30 days of the beginning of production from all wells that would become qualified wells by satisfying the requirements of this section, you must:

(1) Provide written notification to the BSEE Regional Supervisor for Production and Development that production has begun; and

(2) Request confirmation of the size of the royalty suspension volume earned by your lease.

(c) Before beginning production, you must meet any production measurement requirements that the BSEE Regional Supervisor for Production and Development has determined are necessary under 30 CFR part 250, subpart L.

(d) You must provide the information in paragraph (b) of this section by January 20, 2009, if you produced before December 18, 2008, from a qualified deep well or qualified phase 1 ultra-deep well on a lease that is located entirely in water more than 200 meters and less than 400 meters deep.

(e) The BSEE Regional Supervisor for Production and Development may extend the deadline for beginning production for up to one year for a well that cannot begin production before the applicable date prescribed in the definition of ''qualified deep well'' in § 203.0 if it meets all of the following criteria.

(1) The well otherwise meets the criteria in the definition of a qualified deep well in § 203.0.

(2) The delay in production occurred after reaching total depth in the well.

(3) Production (other than test production) was expected to begin from the well before the applicable deadline in the definition of a qualified deep well in § 203.0. You must provide a credible activity schedule with supporting documentation.

(4) The delay in beginning production is for reasons beyond your control, such as adverse weather and accidents which BSEE deems were unavoidable.

§ 203.45 If I drill a certified unsuccessful well, what royalty relief will my lease earn?

Your lease may earn a royalty suspension supplement. Subject to paragraph (d) of this section, the royalty suspension supplement is in addition to any royalty suspension volume your lease may earn under § 203.41.

(a) If you drill a certified unsuccessful well and you satisfy the administrative requirements of § 203.47, subject to the price conditions in § 203.48, your lease earns an RSS shown in the following table. The RSS is shown in billions of cubic feet of gas equivalent (BCFE) or in thousands of cubic feet of gas equivalent (MCFE) and is applicable to oil and gas production as prescribed in § 203.46.

If you have a certified unsuccessful well that is:—	Then your lease earns an RSS on this volume of oil and gas production as prescribed in this section and § 203.46:—
(1) An original well and your lease has not produced gas or oil from a deep well or an ultra-deep well,	5 BCFE.
(2) A sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has not produced gas or oil from a deep well or an ultra-deep well,	0.8 BCFE plus 120 MCFE times sidetrack measured depth (rounded to the nearest 100 feet) but no more than 5 BCFE.
(3) An original well or a sidetrack (with a sidetrack measured depth of at least 10,000 feet) and your lease has produced gas or oil from a deep well with a perforated interval the top of which is from 15,000 to less than 18,000 feet TVD SS,	2 BCFE.

(b) This paragraph applies to oil and gas volumes you report on the OGOR–A for your lease under 30 CFR 1210.102.

(1) You must apply the RSS prescribed in paragraph (a) of this section, in accordance with the requirements in § 203.46, to all oil and gas produced from the lease:

(i) On or after December 18, 2008, if your lease is located in water more than 200 meters but less than 400 meters deep; or

(ii) On or after May 3, 2004, if your lease is located in water partly or entirely less than 200 meters deep.

(2) Production to which an RSV applies under §§ 203.31 through 203.33 and §§ 203.41 through 203.43 does not count toward the lease RSS. All other production, including production that is not subject to royalty, counts toward the lease RSS.

Example 1: If you drill a certified unsuccessful well that is an original well to a target 19,000 feet TVD SS, your lease earns an RSS of 5 BCFE that would be applied to gas

and oil production if your lease has not previously produced from a deep well or an ultra-deep well, or you earn an RSS of 2 BCFE of gas and oil production if your lease has previously produced from a deep well with a perforated interval from 15,000 to less than 18,000 feet TVD SS, as prescribed in § 203.46.

Example 2: If you drill a certified unsuccessful well that is a sidetrack that reaches a target 19,000 feet TVD SS, that has a sidetrack measured depth of 12,545 feet, and your lease has not produced gas or oil from any deep well or ultra-deep well, BSEE rounds the sidetrack measured depth to 12,500 feet and your lease earns an RSS of 2.3 BCFE of gas and oil production as prescribed in § 203.45.

(c) The conversion from oil to gas for using the royalty suspension supplement is specified in § 203.73.

(d) Each lease is eligible for up to two royalty suspension supplements. Therefore, the total royalty suspension supplement for a lease cannot exceed 10 BCFE.

(1) You may not earn more than one royalty suspension supplement from a single wellbore.

(2) If you begin drilling a certified unsuccessful well on one lease but the completion target is on a second lease, the entire royalty suspension supplement belongs to the second lease. However, if the target straddles a lease line, the lease where the surface of the well is located earns the royalty suspension supplement.

(e) If the same wellbore that earns an RSS as a certified unsuccessful well later produces from a perforated interval the top of which is 15,000 feet TVD or deeper and becomes a qualified well, it will be subject to the following conditions:

(1) Beginning on the date production starts, you must stop applying the royalty suspension supplement earned by that wellbore to your lease production.

(2) If the completion of this qualified well is on your lease or, in the case of a directional well, is on another lease, then you must subtract from the royalty suspension volume earned by that qualified well the royalty suspension supplement amounts earned by that wellbore that have already been applied either on your lease or any other lease. The difference represents the royalty suspension volume earned by the qualified well.

(f) If the same wellbore that earned a royalty suspension supplement later has a sidetrack drilled from that wellbore, you are not required to subtract any royalty suspension supplement earned by that wellbore from the royalty suspension volume that may be earned by the sidetrack.

(g) You owe minimum royalties or rentals in accordance with your lease terms notwithstanding any royalty suspension supplements under this section.

§ 203.46 To which production do I apply the royalty suspension supplements from drilling one or two certified unsuccessful wells on my lease?

(a) Subject to the requirements of §§ 203.40, 203.43, 203.45, 203.47, and 203.48 you must apply an RSS in § 203.45 to the earliest oil and gas production:

(1) Occurring on and after the day you file the information under § 203.47(b),

(2) From, or allocated under a BSEE-approved unit agreement to, the lease on which the certified unsuccessful well was drilled, without regard to the drilling depth of the well producing the gas or oil.

(b) If you have a royalty suspension volume for the lease under § 203.41, you must use the royalty suspension volumes for gas produced from qualified wells on the lease before using royalty suspension supplements for gas produced from qualified wells.

Example to paragraph (b): You have two shallow oil wells on your lease. Then you drill a certified unsuccessful well and earn a royalty suspension supplement of 5 BCFE. Thereafter, you begin production from an original well that is a qualified well that earns a royalty suspension volume of 15 BCF. You use only 2 BCFE of the royalty suspension supplement before the oil wells deplete. You must use up the 15 BCF of royalty suspension volume before you use the remaining 3 BCFE of the royalty suspension supplement for gas produced from the qualified well.

(c) If you have no current production on which to apply the RSS allowed under § 203.45, your RSS applies to the earliest subsequent production of gas and oil from, or allocated under a BSEE-approved unit agreement to, your lease.

(d) Unused royalty suspension supplements transfer to a successor lessee and expire with the lease.

(e) You may not apply the RSS allowed under § 203.45 to production from any other lease, except for production allocated to your lease from a BSEE-approved unit agreement. If your certified unsuccessful well is on a lease subject to a BSEE-approved unit agreement, the lessees of other leases in the unit may not apply any portion of the RSS for your lease to production from the other leases in the unit.

(f) You must begin or resume paying royalties when cumulative gas and oil production from, or allocated under a BSEE-approved unit agreement to, your lease (excluding any gas produced from qualified wells subject to a royalty suspension volume allowed under § 203.41) reaches the applicable royalty suspension supplement. For the month in which the cumulative production reaches this royalty suspension supplement, you owe royalties on the portion of gas or oil production that exceeds the amount of the royalty suspension supplement remaining at the beginning of that month.

§ 203.47 What administrative steps do I take to obtain and use the royalty suspension supplement?

(a) Before you start drilling a well on your lease targeted to a reservoir at least 18,000 feet TVD SS, you must notify, in writing, the BSEE Regional Supervisor for Production and Development of your intent to begin drilling operations and the depth of the target.

(b) After drilling the well, you must provide the BSEE Regional Supervisor for Production and Development within 60 days after reaching the total depth in your well:

(1) Information that allows BSEE to confirm that you drilled a certified unsuccessful well as defined under § 203.0, including:

(i) Well log data, if your original well or sidetrack does not meet the producibility requirements of 30 CFR part 550, subpart A; or

(ii) Well log, well test, seismic, and economic data, if your well does meet the producibility requirements of 30 CFR part 550, subpart A; and

(2) Information that allows BSEE to confirm the size of the royalty suspension supplement for a sidetrack, including sidetrack measured depth and supporting documentation.

(c) If you commenced drilling a well that otherwise meets the criteria for a certified unsuccessful well on a lease located entirely in more than 200 meters and entirely less than 400 meters of water on or after May 18, 2007, and finished it before December 18, 2008, you must provide the information in paragraph (b) of this section no later than February 17, 2009.

§ 203.48 Do I keep royalty relief if prices rise significantly?

(a) You must pay royalties on all gas and oil production for which an RSV or an RSS otherwise would be allowed under §§ 203.40 through 203.47 for any calendar year when the average daily closing NYMEX natural gas price exceeds the applicable threshold price shown in the following table.

For a lease located in water . . .	And issued . . .	The applicable threshold price is . . .
(1) Partly or entirely less than 200 meters deep,	before December 18, 2008,	$10.15 per MMBtu, adjusted annually after calendar year 2007 for inflation.
(2) Partly or entirely less than 200 meters deep,	after December 18, 2008,	$4.55 per MMBtu, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.
(3) Entirely more than 200 meters and entirely less than 400 meters deep,	on any date,	$4.55 per MMBtu, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.

(b) Determine the threshold price for any calendar year after 2007 by adjusting the threshold price in the previous year by the percentage that the implicit price deflator for the gross domestic product, as published by the Department of Commerce, changed during the calendar year.

(c) You must pay any royalty due under this section no later than March

31 of the year following the calendar year for which you owe royalty. If you do not pay by that date, you must pay late payment interest under 30 CFR 1218.54 from April 1 until the date of payment.

(d) Production volumes on which you must pay royalty under this section count as part of your RSV and RSS.

§ 203.49 May I substitute the deep gas drilling provisions in this part for the deep gas royalty relief provided in my lease terms?

(a) You may exercise an option to replace the applicable lease terms for royalty relief related to deep-well drilling with those in § 203.0 and §§ 203.40 through 203.48 if you have a lease issued with royalty relief provisions for deep-well drilling. Such leases:

(1) Must be issued as part of an OCS lease sale held after January 1, 2001, and before April 1, 2004; and

(2) Must be located wholly west of 87 degrees, 30 minutes West longitude in the GOM entirely or partly in water less than 200 meters deep.

(b) To exercise the option under paragraph (a) of this section, you must notify, in writing, the BSEE Regional Supervisor for Production and Development of your decision before September 1, 2004, or 180 days after your lease is issued, whichever is later, and specify the lease and block number.

(c) Once you exercise the option under paragraph (a) of this section, you are subject to all the activity, timing, and administrative requirements pertaining to deep gas royalty relief as specified in §§ 203.40 through 203.48.

(d) Exercising the option under paragraph (a) of this section is irrevocable. If you do not exercise this option, then the terms of your lease apply.

ROYALTY RELIEF FOR END-OF-LIFE LEASES

§ 203.50 Who may apply for end-of-life royalty relief?

You may apply for royalty relief in two situations.

(a) Your end-of-life lease (as defined in § 203.2) is an oil and gas lease and has average daily production of at least 100 barrels of oil equivalent (BOE) per month (as calculated in § 203.73) in at least 12 of the past 15 months. The most recent of these 12 months are considered the qualifying months. These 12 months should reflect the basic operation you intend to use until your resources are depleted. If you changed your operation significantly (e.g., begin re-injecting rather than recovering gas) during the qualifying months, or if you do so while we are processing your application, we may defer action on your application until you revise it to show the new circumstances.

(b) Your end-of-life lease is other than an oil and gas lease (e.g., sulphur) and has production in at least 12 of the past 15 months. The most recent of these 12 months are considered the qualifying months.

§ 203.51 How do I apply for end-of-life royalty relief?

You must submit a complete application and the required fee to the appropriate BSEE Regional Director. Your BSEE regional office will provide specific guidance on the report formats. A complete application for relief includes:

(a) An administrative information report (specified in § 203.83) and

(b) A net revenue and relief justification report (specified in § 203.84).

§ 203.52 What criteria must I meet to get relief?

(a) To qualify for relief, you must demonstrate that the sum of royalty payments over the 12 qualifying months exceeds 75 percent of the sum of net revenues (before-royalty revenues minus allowable costs, as defined in § 203.84).

(b) To re-qualify for relief, e.g., either applying for additional relief on top of relief already granted, or applying for relief sometime after your earlier agreement terminated, you must demonstrate that:

(1) You have met the criterion listed in paragraph (a) of this section, and

(2) The 12 required qualifying months of operation have occurred under the current royalty arrangement.

§ 203.53 What relief will BSEE grant?

(a) If we approve your application and you meet certain conditions, we

will reduce the pre-application effective royalty rate by one-half on production up to the relief volume amount. If you produce more than the relief volume amount:

(1) We will impose a royalty rate equal to 1.5 times the effective royalty rate on your additional production up to twice the relief volume amount; and

(2) We will impose a royalty rate equal to the effective rate on all production greater than twice the relief volume amount.

(b) Regardless of the level of production or prices (see § 203.54), royalty payments due under end-of-life relief will not exceed the royalty obligations that would have been due at the effective royalty rate.

(1) The effective royalty rate is the average lease rate paid on production during the 12 qualifying months.

(2) The relief volume amount is the average monthly BOE production for the 12 qualifying months.

§ 203.54 How does my relief arrangement for an oil and gas lease operate if prices rise sharply?

In those months when your current reference price rises by at least 25 percent above your base reference price, you must pay the effective royalty rate on all monthly production.

(a) Your current reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas over the most recent full 12 calendar months;

(b) Your base reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas during the qualifying months; and

(c) Your weighting factors are the proportions of your total production volume (in BOE) provided by oil and gas during the qualifying months.

§ 203.55 Under what conditions can my end-of-life royalty relief arrangement for an oil and gas lease be ended?

(a) If you have an end-of-life royalty relief arrangement, you may renounce it at any time. The lease rate will return to the effective rate during the qualifying period in the first full month following our receipt of your renouncement of the relief arrangement.

(b) If you pay the effective lease rate for 12 consecutive months, we will terminate your relief. The lease rate will return to the effective rate in the first full month following this termination.

(c) We may stipulate in the letter of approval for individual cases certain events that would cause us to terminate relief because they are inconsistent with an end-of-life situation.

§ 203.56 Does relief transfer when a lease is assigned?

Yes. Royalty relief is based on the lease circumstances, not ownership. It transfers upon lease assignment.

Royalty Relief for Pre-Act Deep Water Leases and for Development and Expansion Projects

§ 203.60 Who may apply for royalty relief on a case-by-case basis in deep water in the Gulf of Mexico or offshore of Alaska?

You may apply for royalty relief under §§ 203.61(b) and 203.62 for an individual lease, unit or project if you:

(a) Hold a pre-Act lease (as defined in § 203.0) that we have assigned to an authorized field (as defined in § 203.0);

(b) Propose an expansion project (as defined in § 203.0); or

(c) Propose a development project (as defined in § 203.0).

§ 203.61 How do I assess my chances for getting relief?

You may ask for a nonbinding assessment (a formal opinion on whether a field would qualify for royalty relief) before turning in your first complete application on an authorized field. This field must have a qualifying well under 30 CFR part 550, subpart A, or be on a lease that has allocated production under an approved unit agreement.

(a) To request a nonbinding assessment, you must:

(1) Submit a draft application in the format and detail specified in guidance from the BSEE regional office for the GOM;

(2) Propose to drill at least one more appraisal well if you get a favorable assessment; and

(3) Pay a fee under § 203.3.

(b) You must wait at least 90 days after receiving our assessment to apply for relief under § 203.62.

(c) This assessment is not binding because a complete application may contain more accurate information that does not support our original assessment. It will help you decide whether your proposed inputs for evaluating economic viability and your supporting data and assumptions are adequate.

§ 203.62 How do I apply for relief?

(a) You must send a complete application and the required fee to the BSEE Regional Director for your region.

(b) Your application for royalty relief offshore Alaska or in deep water in the GOM must include an original and two copies (one set of digital information) of:

(1) Administrative information report;

(2) Economic viability and relief justification report;

(3) G&G report;

(4) Engineering report;

(5) Production report; and

(6) Cost report.

(c) Section 203.82 explains why we are authorized to require these reports.

(d) Sections 203.81, 203.83, and 203.85 through 203.89 describe what these reports must include. The BSEE regional office for your region will guide you on the format for the required reports, and we encourage you to contact this office before preparing your application for this guidance.

§ 203.63 Does my application have to include all leases in the field?

(a) For authorized fields, we will accept only one joint application for all leases that are part of the designated field on the date of application, except as provided in paragraph (a)(3) of this section and § 203.64. However, we will evaluate all acreage that may eventually become part of the authorized field. Therefore, if you have any other leases that you believe may eventually be part of the authorized field, you must submit data for these leases according to § 203.81.

(1) The Regional Director maintains a Field Names Master List with updates of all leases in each designated field.

(2) To avoid sharing proprietary data with other lessees on the field, you may submit your proprietary G&G report separately from the rest of your application. Your application is not complete until we receive all the required information for each lease on the field. We will not disclose proprietary data when explaining our assumptions and reasons for our determinations under § 203.67.

(3) We will not require a joint application if you show good cause and honest effort to get all lessees in the field to participate. If you must exclude a lease from your application because its lessee will not participate, that lease is ineligible for the royalty relief for the designated field.

(b) If your application seeks only relief for a development project or an expansion project, your application does not have to include all leases in the field.

§ 203.64 How many applications may I file on a field or a development project?

You may file one complete application for royalty relief during the life of the field or for a development project or an expansion project designed to produce a reservoir or set of reservoirs. However, you may send another application if:

(a) You are eligible to apply for a redetermination under § 203.74;

(b) You apply for royalty relief for an expansion project;

(c) You withdraw the application before we make a determination; or

(d) You apply for end-of-life royalty relief.

§ 203.65 How long will BSEE take to evaluate my application?

(a) We will determine within 20 working days if your application for royalty relief is complete. If your application is incomplete, we will explain in writing what it needs. If you withdraw a complete application, you may reapply.

(b) We will evaluate your first application on a field within 180 days, evaluate your first application on a development project or an expansion project

within 150 days and evaluate a redetermination under § 203.75 within 120 days after we determine that it is complete.

(c) We may ask to extend the review period for your application under the conditions in the following table.

If . . .	Then we may . . .
(1) We need more records to audit sunk costs,	Ask to extend the 120-day or 180-day evaluation period. The extension we request will equal the number of days between when you receive our request for records and the day we receive the records.
(2) We cannot evaluate your application for a valid reason, such as missing vital information or inconsistent or inconclusive supporting data,	Add another 30 days. We may add more than 30 days, but only if you agree.
(3) We need more data, explanations, or revision,	Ask to extend the 120-day or 180-day evaluation period. The extension we request will equal the number of days between when you receive our request and the day we receive the information.

(d) We may change your assumptions under § 203.62 if our technical evaluation reveals others that are more appropriate. We may consult with you before a final decision and will explain any changes.

(e) We will notify all designated lease operators within a field when royalty relief is granted.

§ 203.66 What happens if BSEE does not act in the time allowed?

If we do not act within the timeframes established under § 203.65, you get royalty relief according to the following table.

If you apply for royalty relief for	And we do not decide within the time specified,	As long as you
(a) An authorized field,	You get the minimum suspension volumes specified in § 203.69,	Abide by §§ 203.70 and 203.76.
(b) An expansion project,	You get a royalty suspension for the first year of production,	Abide by §§ 203.70 and 203.76.
(c) A development project,	You get a royalty suspension for initial production for the number of months that a decision is delayed beyond the stipulated timeframes set by § 203.65, plus all the royalty suspension volume for which you qualify,	Abide by §§ 203.70 and 203.76.

§ 203.67 What economic criteria must I meet to get royalty relief on an authorized field or project?

We will not approve applications if we determine that royalty relief cannot make the field, development project, or expansion project economically viable. Your field or project must be uneconomic while you are paying royalties and must become economic with royalty relief.

§ 203.68 What pre-application costs will BSEE consider in determining economic viability?

(a) We will not consider ineligible costs as set forth in § 203.89(h) in determining economic viability for purposes of royalty relief.

(b) We will consider sunk costs according to the following table.

We will . . .	When determining . . .
(1) Include sunk costs,	Whether a field that includes a pre-Act lease which has not produced, other than test production, before the application or redetermination submission date needs relief to become economic.
(2) Not include sunk costs,	Whether an authorized field, a development project, or an expansion project can become economic with full relief (see § 203.67).
(3) Not include sunk costs,	How much suspension volume is necessary to make the field, a development project, or an expansion project economic (see § 203.69(c)).
(4) Include sunk costs for the project discovery well on each lease,	Whether a development project or an expansion project needs relief to become economic.

§ 203.69 If my application is approved, what royalty relief will I receive?

If we approve your application, subject to certain conditions, we will not collect royalties on a specified suspension volume for your field, development project, or expansion project. Suspension volumes include volumes allocated to a lease under an approved unit agreement, but exclude any volumes of production that are not normally royalty-bearing under the lease or the regulations of this chapter (e.g., fuel gas).

(a) For authorized fields, the minimum royalty-suspension volumes are:

(1) 17.5 million barrels of oil equivalent (MMBOE) for fields in 200 to 400 meters of water;

(2) 52.5 MMBOE for fields in 400 to 800 meters of water; and

(3) 87.5 MMBOE for fields in more than 800 meters of water.

(b) For development projects, any relief we grant applies only to project wells and replaces the royalty relief, if any, with which we issued your lease.

(c) If your project is economic given the royalty relief with which we issued your lease, we will reject the application.

(d) If the lease has earned or may earn deep gas royalty relief under §§ 203.40 through 203.49 or ultra-deep gas royalty relief under §§ 203.30 through 203.36, we will take the deep gas royalty relief or ultra-deep gas royalty relief into account in determining whether further royalty relief for a development project is necessary for production to be economic.

(e) If neither paragraph (c) nor (d) of this section apply, the *minimum* royalty suspension volumes are as shown in the following table:

For . . .	The minimum royalty suspension volume is . . .	Plus . . .
(1) RS leases in the GOM or leases offshore Alaska,	A volume equal to the combined royalty suspension volumes (or the volume equivalent based on the data in your approved application for other forms of royalty suspension) with which BSEE issued the leases participating in the application that have or plan a well into a reservoir identified in the application,	10 percent of the median of the distribution of known recoverable resources upon which BSEE based approval of your application from all reservoirs included in the project.
(2) Leases offshore Alaska or other deep water GOM leases issued in sales after November 28, 2000,	A volume equal to 10 percent of the median of the distribution of known recoverable resources upon which BSEE based approval of your application from all reservoirs included in the project.	

(f) If your application includes pre-Act leases in different categories of water depth, we apply the minimum royalty suspension volume for the deepest such lease then assigned to the field. We base the water depth and makeup of a field on the water-depth delineations in the ''Lease Terms and Economic Conditions'' map and the ''Fields Directory'' documents and updates in effect at the time your application is deemed complete. These publications are available from the BSEE Gulf of Mexico Regional Office.

(g) You will get a royalty suspension volume above the minimum if we determine that you need more to make the field or development project economic.

(h) For expansion projects, the minimum royalty suspension volume equals 10 percent of the median of the distribution of known recoverable resources upon which we based approval of your application from all reservoirs included in your project plus any suspension volumes required under § 203.66. If we determine that your expansion project may be economic only with more relief, we will determine and grant you the royalty suspension volume necessary to make the project economic.

(i) The royalty suspension volume applicable to specific leases will continue through the end of the month in which cumulative production reaches that volume. You must calculate cumulative production from all the leases in the authorized field or project that are entitled to share the royalty suspension volume.

§ 203.70 What information must I provide after BSEE approves relief?

You must submit reports to us as indicated in the following table. Sections 203.81, 203.90, and 203.91 describe what these reports must include. The BSEE Regional Office for your region will prescribe the formats.

Required report	When due to BSEE	Due date extensions
(a) Fabricator's confirmation report.	Within 18 months after approval of relief.	BSEE Director may grant you an extension under § 203.79(c) for up to 6 months.
(b) Post-production report.	Within 120 days after the start of production that is subject to the approved royalty suspension volume.	With acceptable justification from you, the BSEE Regional Director for your region may extend the due date up to 30 days.

§ 203.71 How does BSEE allocate a field's suspension volume between my lease and other leases on my field?

The allocation depends on when production occurs, when we issued the lease, when we assigned it to the field, and whether we award the volume suspension by an approved application or establish it in the lease terms, as prescribed in this section.

(a) If your authorized field has an approved royalty suspension volume under §§ 203.67 and 203.69, we will suspend payment of royalties on production from all leases in the field that participate in the application until their cumulative production equals the approved volume. The following conditions also apply:

If . . .	Then . . .	And . . .
(1) We assign an eligible lease to your authorized field after we approve relief,	We will not change your authorized field's royalty suspension volume determined under § 203.69,	Production from the assigned eligible lease(s) counts toward the royalty suspension volume for the authorized field, but the eligible lease will not share any remaining royalty suspension volume for the authorized field after the eligible lease has produced the volume applicable under 30 CFR 560.114.
(2) We assign a pre-Act or post-November 2000 deep water lease to your field after we approve your application,	We will not change your field's royalty suspension volume,	The assigned lease(s) may share in any remaining royalty relief by filing the short-form application specified in § 203.83 and authorized in § 203.82. An assigned RS lease also gets any portion of its royalty suspension volume remaining even after the field has produced the approved relief volume.
(3) We assign another lease that you operate to your field while we are evaluating your application,	In our evaluation of your authorized field, we will take into account the value of any royalty relief the added lease already has under 30 CFR 560.114 or its lease document. If we find your authorized field still needs additional royalty suspension volume, that volume will be at least the combined royalty suspension volume to which all added leases on the field are entitled, or the minimum suspension volume of the authorized field, whichever is greater,	(i) You toll the time period for evaluation until you modify your application to be consistent with the newly constituted field; (ii) We have an additional 60 days to review the new information; and (iii) The assigned pre-Act lease or royalty suspension lease shares the royalty suspension we grant to the newly constituted field. An eligible lease does not share the royalty suspension we grant to the new field. If you do not agree to toll, we will have to reject your application due to incomplete information. Production from an assigned eligible lease counts toward the royalty suspension volume that we grant under § 203.69 for your authorized field, but you will not owe royalty on production from the eligible lease until it has produced the volume applicable under 30 CFR 560.114.

If . . .	Then . . .	And . . .
(4) We assign another operator's lease to your field while we are evaluating your application,	We will change your field's minimum suspension volume provided the assigned lease joins the application and is entitled to a larger minimum suspension volume,	(i) You both toll the time period for evaluation until both of you modify your application to be consistent with the new field; (ii) We have an additional 60 days to review the new information; and (iii) The assigned lease(s) shares the royalty suspension we grant to the new field. If you (the original applicant) do not agree to toll, the other operator's lease retains any suspension volume it has or may share in any relief that we grant by filing the short form application specified in § 203.83 and authorized in § 203.82.
(5) We reassign a well on a pre-Act, eligible, or royalty suspension lease from field A to field B,	The past production from the well counts toward the royalty suspension volume that we grant under § 203.69 to field B,	For any field based relief, the past production for that well will not count toward any royalty suspension volume that we grant under § 203.69 to field A. Moreover, past production from that well will count toward the royalty suspension volume applicable for the lease under 30 CFR 560.114 if the well is on an eligible lease or under 30 CFR 560.124 if the well is on a royalty suspension lease.

(b) When a project has more than one lease, the royalty suspension volume for each lease equals that lease's actual production from the project (or production allocated under an approved unit agreement) until total production for all leases in the project equals the project's approved royalty suspension volume.

(c) You may receive a royalty-suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude. If the field lies on both sides of this meridian, only leases located entirely west of the meridian will receive a royalty-suspension volume.

§ 203.72 Can my lease receive more than one suspension volume?

Yes. You may apply for royalty relief that involves more than one suspension volume under § 203.62 in two circumstances.

(a) Each field that includes your lease may receive a separate royalty-suspension volume, if it meets the evaluation criteria of § 203.67.

(b) An expansion project on your lease may receive a separate royalty-suspension volume, even if we have already granted a royalty-suspension volume to the field that encompasses the project. But the reserves associated with the project must not have been part of our original determination, and the project must meet the evaluation criteria of § 203.67.

§ 203.73 How do suspension volumes apply to natural gas?

You must measure natural gas production under the royalty-suspension volume as follows: 5.62 thousand cubic feet of natural gas, measured in accordance with 30 CFR part 250, subpart L, equals one barrel of oil equivalent.

§ 203.74 When will BSEE reconsider its determination?

You may request a redetermination after we withdraw approval or after you renounce royalty relief, unless we withdraw approval due to your providing false or intentionally inaccurate information. Under certain conditions you may also request a redetermination if we deny your application or if you want your approved royalty suspension volume to change. In these instances, to be eligible for a redetermination, at least one of the following four conditions must occur.

(a) You have significant new G&G data and you previously have not either requested a redetermination or reapplied for relief after we withdrew approval or you relinquished royalty relief. ''Significant'' means that the new G&G data:

(1) Results from drilling new wells or getting new three-dimensional seismic data and information (but not reinterpreting old data);

(2) Did not exist at the time of the earlier application; and

(3) Changes your estimates of gross resource size, quality, or projected flow rates enough to materially affect the results of our earlier determination.

(b) You demonstrate in your new application that the technology that most efficiently develops this field or lease was not considered or deemed feasible in the original application. Your newly proposed technology must improve the profitability, under equivalent market conditions, of the field or lease relative to the development system proposed in the prior application.

(c) Your current reference price decreases by more than 25 percent from your base reference price as calculated under this paragraph.

(1) Your current reference price is a weighted-average of daily closing prices on the NYMEX for light sweet crude oil and natural gas over the most recent full 12 calendar months;

(2) Your base reference price is a weighted average of daily closing prices on the NYMEX for light sweet crude oil and natural gas for the full 12 calendar months preceding the date of your most recently approved application for this royalty relief; and

(3) The weighting factors are the proportions of the total production volume (in BOE) for oil and gas associated with the most likely scenario (identified in §§ 203.85 and 203.88) from your most recently approved application for this royalty relief.

(d) Before starting to build your development and production system, you have revised your estimated development costs, and they are more than 120 percent of the eligible development costs associated with the most likely scenario from your most recently approved application for this royalty relief.

§ 203.75 What risk do I run if I request a redetermination?

If you request a redetermination after we have granted you a suspension volume, you could lose some or all of the previously granted relief. This can happen because you must file a new complete application and pay the required fee, as discussed in § 203.62. We will evaluate your application under § 203.67 using the conditions prevailing at the time of your redetermination request. In our evaluation, we may find that you should receive a larger, equivalent, smaller, or no suspension volume. This means we could find that you do not qualify for the amount of relief previously granted or for any relief at all.

§ 203.76 When might BSEE withdraw or reduce the approved size of my relief?

We will withdraw approval of relief for any of the following reasons.

(a) You change the type of development system proposed in your application (e.g., change from a fixed platform to floating production system, or from an independent development and production system to one with subsea wells tied back to a host production facility, *etc.*).

(b) You do not start building the proposed development and production system within 18 months of the date we approved your application, unless the BSEE Director grants you an extension under § 203.79(c). If you start building the proposed system and then suspend its construction before completion, and you do not restart continuous building of the proposed system within 18 months of our approval, we will withdraw the relief we granted.

(c) Your actual development costs are less than 80 percent of the eligible development costs estimated in your application's most likely scenario, and you do not report that fact in your post-production development report (§ 203.70). Development costs are those expenditures defined in § 203.89(b) incurred between the application submission date and start of production. If you report this fact in the post-production development report, you may retain the lesser of 50 percent of the original royalty suspension volume or 50 percent of the median of the distribution of the potentially recoverable resources anticipated in your application.

(d) We granted you a royalty-suspension volume after you qualified for a redetermination under § 203.74(c), and we find out your actual development costs are less than 90 percent of the eligible development costs associated with your application's most likely scenario. Development costs are those

expenditures defined in § 203.89(b) incurred between your application submission date and start of production.

(e) You do not send us the fabrication confirmation report or the post-production development report, or you provide false or intentionally inaccurate information that was material to our granting royalty relief under this section. You must pay royalties and late-payment interest determined under 30 U.S.C. 1721 and 30 CFR 1218.54 on all volumes for which you used the royalty suspension. You also may be subject to penalties under other provisions of law.

§ 203.77 May I voluntarily give up relief if conditions change?

Yes, you may voluntarily give up relief by sending a letter to that effect to the BSEE Regional office for your region.

§ 203.78 Do I keep relief approved by BSEE under this part for my lease, unit or project if prices rise significantly?

If prices rise above a base price threshold for light sweet crude oil or natural gas, you must pay full royalties on production otherwise subject to royalty relief approved by BSEE under §§ 203.60–203.77 for your lease, unit or project as prescribed in this section.

(a) The following table shows the base price threshold for various types of leases, subject to paragraph (b) of this section. Note that, for post-November 2000 deepwater leases in the GOM, price thresholds apply on a lease basis, so different leases on the same development project or expansion project approved for royalty relief may have different price thresholds.

For . . .	The base price threshold is . . .
(1) Pre-Act leases in the GOM,	set by statute.
(2) Post-November 2000 deep water leases in the GOM or leases offshore of Alaska for which the lease or Notice of Sale set a base price threshold,	indicated in your original lease agreement or, if none, those in the Notice of Sale under which your lease was issued.
(3) Post-November 2000 deep water leases in the GOM or leases offshore of Alaska for which the lease or Notice of Sale did not set a base price threshold,	the threshold set by statute for pre-Act leases.

(b) An exception may occur if we determine that the price thresholds in paragraphs (a)(2) or (a)(3) of this section mean the royalty suspension volume set under § 203.69 and in lease terms would provide inadequate encouragement to increase production or development, in which circumstance we could specify a different set of price thresholds on a case-by-case basis.

(c) Suppose your base oil price threshold set under paragraph (a) is $28.00 per barrel, and the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $28.00 per barrel, as adjusted in paragraph (h) of this section. In this case, we retract the royalty relief authorized in this subpart and you must:

(1) Pay royalties on all oil production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and 30 CFR 1218.54) by March 31 of the current calendar year, and

(2) Pay royalties on all your oil production in the current year.

(d) Suppose your base gas price threshold set under paragraph (a) is $3.50 per million British thermal units (Btu), and the daily closing NYMEX light sweet crude oil prices for the previous calendar year exceeds $3.50 per million Btu, as adjusted in paragraph (h) of this section. In this case, we retract the royalty relief authorized in this subpart and you must:

(1) Pay royalties on all gas production for the previous year at the lease stipulated royalty rate plus interest (under 30 U.S.C. 1721 and 30 CFR 1218.54) by March 31 of the current calendar year, and

(2) Pay royalties on all your gas production in the current year.

(e) Production under both paragraphs (c) and (d) of this section counts as part of the royalty-suspension volume.

(f) You are entitled to a refund or credit, with interest, of royalties paid on any production (that counts as part of the royalty-suspension volume):

(1) Of oil if the arithmetic average of the closing prices for the current calendar year is $28.00 per barrel or less, as adjusted in paragraph (h) of this section, and

(2) Of gas if the arithmetic average of the closing natural gas prices for the current calendar year is $3.50 per million Btu or less, as adjusted in paragraph (h) of this section.

(g) You must follow our regulations in the Office of Natural Resources Revenue, 30 CFR chapter XII, for receiving refunds or credits.

(h) We change the prices referred to in paragraphs (c), (d), and (f) of this section periodically. For pre-Act leases, these prices change during each calendar year after 1994 by the percentage that the implicit price deflator for the gross domestic product changed during the preceding calendar year. For post-November 2000 deepwater leases, these prices change as indicated in the lease instrument or in the Notice of Sale under which we issued the lease.

§ 203.79 How do I appeal BSEE's decisions related to royalty relief for a deepwater lease or a development or expansion project?

(a) Once we have designated your lease as part of a field and notified you and other affected operators of the designation, you can request reconsideration by sending the BSEE Director a letter within 15 days that also states your reasons. The BSEE Director's response is the final agency action.

(b) Our decisions on your application for relief from paying royalty under § 203.67 and the royalty-suspension volumes under § 203.69 are final agency actions.

(c) If you cannot start construction by the deadline in § 203.76(b) for reasons beyond your control (e.g., strike at the fabrication yard), you may request an extension up to 1 year by writing the BSEE Director and stating your reasons. The BSEE Director's response is the final agency action.

(d) We will notify you of all final agency actions by certified mail, return receipt requested. Final agency actions are not subject to appeal to the Interior Board of Land Appeals under 30 CFR part 290 and 43 CFR part 4. They 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 our decision.

§ 203.80 When can I get royalty relief if I am not eligible for royalty relief under other sections in the subpart?

We may grant royalty relief when it serves the statutory purposes summarized in § 203.1 and our formal relief programs, including but not limited to the applicable levels of the royalty suspension volumes and price thresholds, provide inadequate encouragement to promote development or increase production. Unless your lease lies offshore of Alaska or wholly west of 87 degrees, 30 minutes West longitude in the GOM, your lease must be producing to qualify for relief. Before you may apply for royalty relief apart from our programs for end-of-life leases or for pre-Act deep water leases and development and expansion projects, we must agree that your lease or project has two or more of the following characteristics:

(a) The lease has produced for a substantial period and the lessee can recover significant additional resources. Significant additional resources mean enough to allow production for at least a year more than would be profitable without royalty relief.

(b) Valuable facilities (e.g., a platform or pipeline that would be removed upon lease relinquishment) exist that we do not expect a successor lessee to use. If the facilities are located off the lease, their preservation must depend on continued production from the lease applying for royalty relief. We will only consider an allocable share of costs for off-lease facilities in the relief application.

(c) A substantial risk exists that no new lessee will recover the resources.

(d) The lessee made major efforts to reduce operating costs too recently to use the formal program for royalty relief (e.g., recent significant change in operations).

(e) Circumstances beyond the lessee's control, other than water depth, preclude reliance on one of the existing royalty relief programs.

REQUIRED REPORTS

§ 203.81 What supplemental reports do royalty-relief applications require?

(a) You must send us the supplemental reports, indicated in the following table by an X, that apply to your field. Sections 203.83 through 203.91 describe these reports in detail.

Required reports	End-of-life lease	Deep water		
		Expansion project	Pre-act lease	Development project
(1) Administrative information Report	X	X	X	X
(2) Net revenue & relief justification report	X			
(3) Economic viability & relief justification report (RSVP model inputs justified by other required reports)		X	X	X
(4) G&G report		X	X	X
(5) Engineering report		X	X	X
(6) Production report		X	X	X
(7) Deep water cost report		X	X	X
(8) Fabricator's confirmation report		X	X	X
(9) Post-production development report		X	X	X

(b) You must certify that all information in your application, fabricator's confirmation and post-production development reports is accurate, complete, and conforms to the most recent content and presentation guidelines available from the BSEE Regional office for your region.

(c) With your application and post-production development report, you must submit an additional report prepared by an independent CPA that:

(1) Assesses the accuracy of the historical financial information in your report; and

(2) Certifies that the content and presentation of the financial data and information conform to our most recent guidelines on royalty relief. This means the data and information must:

(i) Include only eligible costs that are incurred during the qualification months; and

(ii) Be shown in the proper format.

(d) You must identify the people in the CPA firm who prepared the reports referred to in paragraph (c) of this section and make them available to us to respond to questions about the historical financial information. We may also further review your records to support this information.

§ 203.82 What is BSEE's authority to collect this information?

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.

(a) We use the information to determine whether royalty relief will result in production that wouldn't otherwise occur. We rely largely on your information to make these determinations.

(1) Your application for royalty relief must contain enough information on finances, economics, reservoirs, G&G characteristics, production, and engineering estimates for us to determine whether:

(i) We should grant relief under the law, and

(ii) The requested relief will ultimately recover more resources and return a reasonable profit on project investments.

(2) Your fabricator confirmation and post-production development reports must contain enough information for us to verify that your application reasonably represented your plans.

(b) Applicants (respondents) are Federal OCS oil and gas lessees. Applications are required to obtain or retain a benefit. Therefore, if you apply for royalty relief, you must provide this information. We will protect information considered proprietary under applicable law and under regulations at § 203.63 and 30 CFR part 250.

(c) The Paperwork Reduction Act of 1995 requires us to inform you that we 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.

(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, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36148, June 6, 2016]

§ 203.83 What is in an administrative information report?

This report identifies the field or lease for which royalty relief is requested and must contain the following items:

(a) The field or lease name;

(b) The serial number of leases we have assigned to the field, names of the lease title holders of record, the lease operators, and whether any lease is part of a unit;

(c) Well number, API number, location, and status of each well that has been drilled on the field or lease or project (not required for non-oil and gas leases);

(d) The location of any new wells proposed under the terms of the application (not required for non-oil and gas leases);

(e) A description of field or lease history;

(f) Full information as to whether you will pay royalties or a share of production to anyone other than the United States, the amount you will pay, and how much you will reduce this payment if we grant relief;

(g) The type of royalty relief you are requesting;

(h) Confirmation that BOEM approved a DOCD or supplemental DOCD (Deep Water expansion project applications only); and

(i) 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 (Deep Water applications only).

§ 203.84 What is in a net revenue and relief justification report?

This report presents cash flow data for 12 qualifying months, using the format specified in the ''Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases'', U.S. Department of the Interior, BSEE. Qualifying months for an oil and gas lease are the most recent 12 months out of the last 15 months that you produced at least 100 BOE per day on average. Qualifying months for other than oil and gas leases are the most recent 12 of the last 15 months having some production.

(a) The cash flow table you submit must include historical data for:

(1) Lease production subject to royalty;

(2) Total revenues;

(3) Royalty payments out of production;

(4) Total allowable costs; and

(5) Transportation and processing costs.

(b) Do not include in your cash flow table the non-allowable costs listed at 30 CFR 1220.013 or:

(1) OCS rental payments on the lease(s) in the application;

(2) Damages and losses;

(3) Taxes;

(4) Any costs associated with exploratory activities;

(5) Civil or criminal fines or penalties;

(6) Fees for your royalty relief application; and

(7) Costs associated with existing obligations (e.g., royalty overrides or other forms of payment for acquiring the lease, depreciation on previously acquired equipment or facilities).

(c) We may, in reviewing and evaluating your application, disallow costs when you have not shown they are necessary to operate the lease, or if they are inconsistent with end-of-life operations.

§ 203.85 What is in an economic viability and relief justification report?

This report should show that your project appears economic without royalties and sunk costs using the RSVP model we provide. The format of the report and the assumptions and parameters we specify are found in the ''Guidelines for the Application, Review, Approval and Administration of the Deep Water Royalty Relief Program,'' U.S. Department of the Interior, BSEE. Clearly justify each parameter you set in every scenario you

specify in the RSVP. You may provide supplemental information, including your own model and results. The economic viability and relief justification report must contain the following items for an oil and gas lease.

(a) Economic assumptions we provide which include:

(1) Starting oil and gas prices;

(2) Real price growth;

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

(4) Base year;

(5) Range of discount rates; and

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

(b) Analysis of projected cash flow (from the date of the application using annual totals and constant dollar values) which shows:

(1) Oil and gas production;

(2) Total revenues;

(3) Capital expenditures;

(4) Operating costs;

(5) Transportation costs; and

(6) Before-tax net cash flow without royalties, overrides, sunk costs, and ineligible costs.

(c) Discounted values which include:

(1) Discount rate used (selected from within the range we specify).

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

(d) Demonstrations that:

(1) All costs, gross production, and scheduling are consistent with the data in the G&G, engineering, production, and cost reports (§§ 203.86 through 203.89) and

(2) The development and production scenarios provided in the various reports are consistent with each other and with the proposed development system. You can use up to three scenarios (conservative, most likely, and optimistic), but you must link each to a specific range on the distribution of resources from the RSVP Resource Module.

§ 203.86 What is in a G&G report?

This report supports the reserve and resource estimates used in the economic evaluation and must contain each of the following elements.

(a) Seismic data which includes:

(1) Non-interpreted 2D/3D survey lines reflecting any available state-of-the-art processing technique in a format readable by BSEE and specified by the deep water royalty relief guidelines;

(2) Interpreted 2D/3D seismic survey lines reflecting any available state-of-the-art processing technique identifying all known and prospective pay horizons, wells, and fault cuts;

(3) Digital velocity surveys in the format of the GOM region's letter to lessees of 10/1/90;

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

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

(b) Well data which includes:

(1) Hard copies of all well logs in which—

(i) The 1-inch electric log shows pay zones and pay counts and lithologic and paleo correlation markers at least every 500-feet,

(ii) The 1-inch type log shows missing sections from other logs where faulting occurs,

(iii) The 5-inch electric log shows pay zones and pay counts and labeled points used in establishing resistivity of the formation, 100 percent water saturated (R_o) and the resistivity of the undisturbed formation (R_t), and

(iv) The 5-inch porosity logs show pay zones and pay counts and labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time;

(2) Digital copies of all well logs spudded before December 1, 1995;

(3) Core data, if available;

(4) Well correlation sections;

(5) Pressure data;

(6) Production test results;

(7) Pressure-volume-temperature analysis, if available; and

(8) A table listing the wells and completions, and indicating which sands and fault blocks will be targeted for completion or recompletion.

(c) Map interpretations which includes for each reservoir in the field:

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

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

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

(4) An explanation for excluding the reservoirs you are not planning to develop.

(d) Reservoir-specific data which includes:

(1) Probability of reservoir occurrence with hydrocarbons;

(2) Probability the hydrocarbon in the reservoir is all oil and the probability it is all gas;

(3) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for the parameters used to estimate reservoir size, *i.e.*, acres and net thickness;

(4) Most likely values for porosity, salt water saturation, volume factor for oil formation, and volume factor for gas formation;

(5) Distributions or point estimates (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for recovery efficiency (in percent) and oil or gas recovery (in stock-tank-barrels per acre-foot or in thousands of cubic feet per acre foot);

(6) A gas/oil ratio distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each reservoir;

(7) A yield distribution or point estimate (accompanied by explanations of why distributions less appropriately reflect the uncertainty) for each gas reservoir; and

(8) Reserve or resource distribution by reservoir.

(e) Aggregated reserve and resource data which includes:

(1) The aggregated distributions for reserves and resources (in BOE) and oil fraction for your field computed by the resource module of our RSVP model;

(2) A description of anticipated hydrocarbon quality (*i.e.*, specific gravity); and

(3) The ranges within the aggregated distribution for reserves and resources that define the development and production scenarios presented in the engineering and production reports. Typically there will be three ranges specified by two positive reserve and resource points on the aggregated distribution. The range at the low end of the distribution will be associated with the conservative development and production scenario; the middle range will be related to the most likely development and production scenario; and, the high end range will be consistent with the optimistic development and production scenario.

§ 203.87 What is in an engineering report?

This report defines the development plan and capital requirements for the economic evaluation and must contain the following elements.

(a) A description of the development concept (e.g., tension leg platform, fixed platform, floater type, subsea tieback, *etc.*) which includes:

(1) Its size along with basic design specifications and drawings; and

(2) The construction schedule.

(b) An identification of planned wells which includes:

(1) The number;

(2) The type (platform, subsea, vertical, deviated, horizontal);

(3) The well depth;

(4) The drilling schedule;

(5) The kind of completion (single, dual, horizontal, *etc.*); and

(6) The completion schedule.

(c) A description of the production system equipment which includes:

(1) The production capacity for oil and gas and a description of limiting component(s);

(2) Any unusual problems (low gravity, paraffin, *etc.*);

(3) All subsea structures;

(4) All flowlines; and

(5) Schedule for installing the production system.

(d) A discussion of any plans for multi-phase development which includes the conceptual basis for developing in phases and goals or milestones required for starting later phases.

(e) A set of development scenarios consisting of activity timing and scale associated with each of up to three production profiles (conservative, most likely, optimistic) provided in the production report for your field (§ 203.88). Each development scenario and production profile must denote the likely

events should the field size turn out to be within a range represented by one of the three segments of the field size distribution. If you send in fewer than three scenarios, you must explain why fewer scenarios are more efficient across the whole field size distribution.

§ 203.88 What is in a production report?

This report supports your development and production timing and product quality expectations and must contain the following elements.

(a) Production profiles by well completion and field that specify the actual and projected production by year for each of the following products: oil, condensate, gas, and associated gas. The production from each profile must be consistent with a specific level of reserves and resources on the aggregated distribution of field size.

(b) Production drive mechanisms for each reservoir.

§ 203.89 What is in a cost report?

This report lists all actual and projected costs for your field, must explain and document the source of each cost estimate, and must identify the following elements.

(a) *Sunk costs*. Report sunk costs in dollars not adjusted for inflation and only if you have documentation.

(b) *Appraisal, delineation and development costs*. Base them on actual spending, current authorization for expenditure, engineering estimates, or analogous projects. These costs cover:

(1) Platform well drilling and average depth;

(2) Platform well completion;

(3) Subsea well drilling and average depth;

(4) Subsea well completion;

(5) Production system (platform); and

(6) Flowline fabrication and installation.

(c) *Production costs based on historical costs, engineering estimates, or analogous projects*. These costs cover:

(1) Operation;

(2) Equipment; and

(3) Existing royalty overrides (we will not use the royalty overrides in evaluations).

(d) *Transportation costs, based on historical costs, engineering estimates, or analogous projects*. These costs cover:

(1) Oil or gas tariffs from pipeline or tankerage;

(2) Trunkline and tieback lines; and

(3) Gas plant processing for natural gas liquids.

(e) *Abandonment costs, based on historical costs, engineering estimates, or analogous projects*. You should provide the costs to plug and abandon only wells and to remove only production systems for which you have not incurred costs as of the time of application submission. You should also include a point estimate or distribution of prospective salvage value for all potentially reusable facilities and materials, along with the source and an explanation of the figures provided.

(f) *A set of cost estimates consistent with each one of up to three field-development scenarios and production profiles (conservative, most likely, optimistic)*. You should express costs in constant real dollar terms for the base year. You may also express the uncertainty of each cost estimate with a minimum and maximum percentage of the base value.

(g) *A spending schedule*. You should provide costs for each year (in real dollars) for each category in paragraphs (a) through (f) of this section.

(h) *A summary of other costs which are ineligible for evaluating your need for relief*. These costs cover:

(1) Expenses before first discovery on the field;

(2) Cash bonuses;

(3) Fees for royalty relief applications;

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

(5) Legal expenses;

(6) Damages and losses;

(7) Taxes;

(8) Interest or finance charges, including those embedded in equipment leases;

(9) Fines or penalties; and

(10) Money spent on previously existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease, expenditures for plugging wells and removing and abandoning facilities that

existed on the application submission date).

§ 203.90 What is in a fabricator's confirmation report?

This report shows you have committed in a timely way to the approved system for production. This report must include the following (or its equivalent for unconventionally acquired systems):

(a) A copy of the contract(s) under which the fabrication yard is building the approved system for you;

(b) A letter from the contractor building the system to the BSEE Regional Director for your region certifying when construction started on your system; and

(c) Evidence of an appropriate down payment or equal action that you've started acquiring the approved system.

§ 203.91 What is in a post-production development report?

For each cost category in the deep water cost report, you must compare actual costs up to the date when production starts to your planned pre-production costs. If your application included more than one development scenario, you need to compare actual costs with those in your scenario of most likely development. Also, you must have this report certified by an independent CPA according to § 203.81(c).

Subpart C—Federal and Indian Oil [Reserved]

Subpart D—Federal and Indian Gas [Reserved]

Subpart E—Solid Minerals, General [Reserved]

Subpart F [Reserved]

Subpart G—Other Solid Minerals [Reserved]

Subpart H—Geothermal Resources [Reserved]

Subpart I—OCS Sulfur [Reserved]

SUBCHAPTER B—OFFSHORE

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

Subpart A—General

AUTHORITY AND DEFINITION OF TERMS

Sec.
250.101 Authority and applicability.
250.102 What does this part do?
250.103 Where can I find more information about the requirements in this part?
250.104 How may I appeal a decision made under BSEE regulations?
250.105 Definitions.

PERFORMANCE STANDARDS

250.106 What standards will the Director use to regulate lease operations?
250.107 What must I do to protect health, safety, property, and the environment?
250.108 What requirements must I follow for cranes and other material-handling equipment?
250.109 What documents must I prepare and maintain related to welding?
250.110 What must I include in my welding plan?
250.111 Who oversees operations under my welding plan?
250.112 What standards must my welding equipment meet?
250.113 What procedures must I follow when welding?
250.114 How must I install, maintain, and operate electrical equipment?
250.115 What are the procedures for, and effects of, incorporation of documents by reference in this part?
250.116–250.117 [Reserved]

GAS STORAGE OR INJECTION

250.118 Will BSEE approve gas injection?
250.119 [Reserved]
250.120 How does injecting, storing, or treating gas affect my royalty payments?
250.121 What happens when the reservoir contains both original gas in place and injected gas?
250.122 What effect does subsurface storage have on the lease term?
250.123 [Reserved]
250.124 Will BSEE approve gas injection into the cap rock containing a sulphur deposit?

FEES

250.125 Service fees.
250.126 Electronic payment instructions.

INSPECTION OF OPERATIONS

250.130 Why does BSEE conduct inspections?
250.131 Will BSEE notify me before conducting an inspection?
250.132 What must I do when BSEE conducts an inspection?
250.133 Will BSEE reimburse me for my expenses related to inspections?

DISQUALIFICATION

250.135 What will BSEE do if my operating performance is unacceptable?
250.136 How will BSEE determine if my operating performance is unacceptable?

SPECIAL TYPES OF APPROVALS

250.140 When will I receive an oral approval?
250.141 May I ever use alternate procedures or equipment?
250.142 How do I receive approval for departures?
250.143–250.144 [Reserved]
250.145 How do I designate an agent or a local agent?
250.146 Who is responsible for fulfilling leasehold obligations?

NAMING AND IDENTIFYING FACILITIES AND WELLS (DOES NOT INCLUDE MODUS)

250.150 How do I name facilities and wells in the Gulf of Mexico Region?
250.151 How do I name facilities in the Pacific Region?
250.152 How do I name facilities in the Alaska Region?
250.153 Do I have to rename an existing facility or well?
250.154 What identification signs must I display?
250.160–250.167 [Reserved]

SUSPENSIONS

250.168 May operations or production be suspended?
250.169 What effect does suspension have on my lease?
250.170 How long does a suspension last?
250.171 How do I request a suspension?
250.172 When may the Regional Supervisor grant or direct an SOO or SOP?
250.173 When may the Regional Supervisor direct an SOO or SOP?
250.174 When may the Regional Supervisor grant or direct an SOP?
250.175 When may the Regional Supervisor grant an SOO?
250.176 Does a suspension affect my royalty payment?
250.177 What additional requirements may the Regional Supervisor order for a suspension?

PRIMARY LEASE REQUIREMENTS, LEASE TERM EXTENSIONS, AND LEASE CANCELLATIONS

250.180 What am I required to do to keep my lease term in effect?
250.181–250.185 [Reserved]

INFORMATION AND REPORTING REQUIREMENTS

250.186 What reporting information and report forms must I submit?
250.187 What are BSEE's incident reporting requirements?
250.188 What incidents must I report to BSEE and when must I report them?
250.189 Reporting requirements for incidents requiring immediate notification.
250.190 Reporting requirements for incidents requiring written notification.
250.191 How does BSEE conduct incident investigations?
250.192 What reports and statistics must I submit relating to a hurricane, earthquake, or other natural occurrence?
250.193 Reports and investigations of possible violations.
250.194 How must I protect archaeological resources?
250.195 What notification does BSEE require on the production status of wells?
250.196 Reimbursements for reproduction and processing costs.
250.197 Data and information to be made available to the public or for limited inspection.

REFERENCES

250.198 Documents incorporated by reference.
250.199 Paperwork Reduction Act statements—information collection.

Subpart B—Plans and Information

GENERAL INFORMATION

250.200 Definitions.
250.201 What plans and information must I submit before I conduct any activities on my lease or unit?
250.202–250.203 [Reserved]
250.204 How must I protect the rights of the Federal government?
250.205 Are there special requirements if my well affects an adjacent property?

POST-APPROVAL REQUIREMENTS FOR THE EP, DPP, AND DOCD

250.282 Do I have to conduct post-approval monitoring?

DEEPWATER OPERATIONS PLANS (DWOP)

250.286 What is a DWOP?
250.287 For what development projects must I submit a DWOP?
250.288 When and how must I submit the Conceptual Plan?
250.289 What must the Conceptual Plan contain?
250.290 What operations require approval of the Conceptual Plan?
250.291 When and how must I submit the DWOP?
250.292 What must the DWOP contain?
250.293 What operations require approval of the DWOP?
250.294 May I combine the Conceptual Plan and the DWOP?
250.295 When must I revise my DWOP?

Subpart C—Pollution Prevention and Control

250.300 Pollution prevention.
250.301 Inspection of facilities.

Subpart D—Oil and Gas Drilling Operations

GENERAL REQUIREMENTS

250.400 General requirements.
250.401–250.403 [Reserved]
250.404 What are the requirements for the crown block?
250.405 What are the safety requirements for diesel engines used on a drilling rig?
250.406 [Reserved]
250.407 What tests must I conduct to determine reservoir characteristics?
250.408 May I use alternative procedures or equipment during drilling operations?
250.409 May I obtain departures from these drilling requirements?

APPLYING FOR A PERMIT TO DRILL

250.410 How do I obtain approval to drill a well?
250.411 What information must I submit with my application?
250.412 What requirements must the location plat meet?
250.413 What must my description of well drilling design criteria address?
250.414 What must my drilling prognosis include?
250.415 What must my casing and cementing programs include?
250.416 What must I include in the diverter description?
250.417 [Reserved]
250.418 What additional information must I submit with my APD?

CASING AND CEMENTING REQUIREMENTS

250.420 What well casing and cementing requirements must I meet?
250.421 What are the casing and cementing requirements by type of casing string?
250.422 When may I resume drilling after cementing?
250.423 What are the requirements for casing and liner installation?
250.424–250.426 [Reserved]

250.427 What are the requirements for pressure integrity tests?
250.428 What must I do in certain cementing and casing situations?

DIVERTER SYSTEM REQUIREMENTS

250.430 When must I install a diverter system?
250.431 What are the diverter design and installation requirements?
250.432 How do I obtain a departure to diverter design and installation requirements?
250.433 What are the diverter actuation and testing requirements?
250.434 What are the recordkeeping requirements for diverter actuations and tests?
250.440–250.451 [Reserved]

DRILLING FLUID REQUIREMENTS

250.452 What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations?
250.455 What are the general requirements for a drilling fluid program?
250.456 What safe practices must the drilling fluid program follow?
250.457 What equipment is required to monitor drilling fluids?
250.458 What quantities of drilling fluids are required?
250.459 What are the safety requirements for drilling fluid-handling areas?

OTHER DRILLING REQUIREMENTS

250.460 What are the requirements for conducting a well test?
250.461 What are the requirements for directional and inclination surveys?
250.462 What are the requirements for well-control drills?
250.463 Who establishes field drilling rules?

APPLYING FOR A PERMIT TO MODIFY AND WELL RECORDS

250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to BSEE?
250.466–250.469 [Reserved]

ADDITIONAL ARCTIC OCS REQUIREMENTS

250.470 What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?
250.471 What are the requirements for Arctic OCS source control and containment?
250.472 What are the relief rig requirements for the Arctic OCS?
250.473 What must I do to protect health, safety, property, and the environment while operating on the Arctic OCS?

HYDROGEN SULFIDE

250.490 Hydrogen sulfide.

Subpart E—Oil and Gas Well-Completion Operations

250.500 General requirements.
250.501 Definition.
250.502 [Reserved]
250.503 Emergency shutdown system.
250.504 Hydrogen sulfide.
250.505 Subsea completions.
250.506–250.508 [Reserved]
250.509 Well-completion structures on fixed platforms.
250.510 Diesel engine air intakes.
250.511 Traveling-block safety device.
250.512 Field well-completion rules.
250.513 Approval and reporting of well-completion operations.
250.514 Well-control fluids, equipment, and operations.
250.515–250.517 [Reserved]
250.518 Tubing and wellhead equipment.

CASING PRESSURE MANAGEMENT

250.519 What are the requirements for casing pressure management?
250.520 How often do I have to monitor for casing pressure?
250.521 When do I have to perform a casing diagnostic test?
250.522 How do I manage the thermal effects caused by initial production on a newly completed or recompleted well?
250.523 When do I have to repeat casing diagnostic testing?
250.524 How long do I keep records of casing pressure and diagnostic tests?
250.525 When am I required to take action from my casing diagnostic test?
250.526 What do I submit if my casing diagnostic test requires action?
250.527 What must I include in my notification of corrective action?
250.528 What must I include in my casing pressure request?
250.529 What are the terms of my casing pressure request?
250.530 What if my casing pressure request is denied?
250.531 When does my casing pressure request approval become invalid?

Subpart F—Oil and Gas Well-Workover Operations

250.600 General requirements.
250.601 Definitions.
250.602 [Reserved]
250.603 Emergency shutdown system.
250.604 Hydrogen sulfide.
250.605 Subsea workovers.
250.606–250.608 [Reserved]
250.609 Well-workover structures on fixed platforms.
250.610 Diesel engine air intakes.
250.611 Traveling-block safety device.
250.612 Field well-workover rules.

250.613 Approval and reporting for well-workover operations.
250.614 Well-control fluids, equipment, and operations.
250.615 [Reserved]
250.616 Coiled tubing and snubbing operations.
250.617–250.618 [Reserved]
250.619 Tubing and wellhead equipment.
250.620 Wireline operations.

Subpart G—Well Operations and Equipment

GENERAL REQUIREMENTS

250.700 What operations and equipment does this subpart cover?
250.701 May I use alternate procedures or equipment during operations?
250.702 May I obtain departures from these requirements?
250.703 What must I do to keep wells under control?

RIG REQUIREMENTS

250.710 What instructions must be given to personnel engaged in well operations?
250.711 What are the requirements for well-control drills?
250.712 What rig unit movements must I report?
250.713 What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations?
250.714 Do I have to develop a dropped objects plan?
250.715 Do I need a global positioning system (GPS) for all MODUs?

WELL OPERATIONS

250.720 When and how must I secure a well?
250.721 What are the requirements for pressure testing casing and liners?
250.722 What are the requirements for prolonged operations in a well?
250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?
250.724 What are the real-time monitoring requirements?

BLOWOUT PREVENTER (BOP) SYSTEM REQUIREMENTS

250.730 What are the general requirements for BOP systems and system components?
250.731 What information must I submit for BOP systems and system components?
250.732 What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components?
250.733 What are the requirements for a surface BOP stack?
250.734 What are the requirements for a subsea BOP system?
250.735 What associated systems and related equipment must all BOP systems include?
250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?
250.737 What are the BOP system testing requirements?
250.738 What must I do in certain situations involving BOP equipment or systems?
250.739 What are the BOP maintenance and inspection requirements?

RECORDS AND REPORTING

250.740 What records must I keep?
250.741 How long must I keep records?
250.742 What well records am I required to submit?
250.743 What are the well activity reporting requirements?
250.744 What are the end of operation reporting requirements?
250.745 What other well records could I be required to submit?
250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

COILED TUBING OPERATIONS

250.750 xxx
250.751 xxx

SNUBBING OPERATIONS

250.760 xxx

Subpart H—Oil and Gas Production Safety Systems

GENERAL REQUIREMENTS

250.800 General.
250.801 Safety and pollution prevention equipment (SPPE) certification.
250.802 Requirements for SPPE.
250.803 What SPPE failure reporting procedures must I follow?
250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature (HPHT) environments.
250.805 Hydrogen sulfide.
250.806–250.809 [Reserved]

SURFACE AND SUBSURFACE SAFETY SYSTEMS—DRY TREES

250.810 Dry tree subsurface safety devices—general.
250.811 Specifications for SSSVs—dry trees.
250.812 Surface-controlled SSSVs—dry trees.
250.813 Subsurface-controlled SSSVs.
250.814 Design, installation, and operation of SSSVs—dry trees.

250.815 Subsurface safety devices in shut-in wells—dry trees.
250.816 Subsurface safety devices in injection wells—dry trees.
250.817 Temporary removal of subsurface safety devices for routine operations.
250.818 Additional safety equipment—dry trees.
250.819 Specification for surface safety valves (SSVs).
250.820 Use of SSVs.
250.821 Emergency action and safety system shutdown—dry trees.
250.822–250.824 [Reserved]

SUBSEA AND SUBSURFACE SAFETY SYSTEMS—SUBSEA TREES

250.825 Subsea tree subsurface safety devices—general.
250.826 Specifications for SSSVs—subsea trees.
250.827 Surface-controlled SSSVs—subsea trees.
250.828 Design, installation, and operation of SSSVs—subsea trees.
250.829 Subsurface safety devices in shut-in wells—subsea trees.
250.830 Subsurface safety devices in injection wells—subsea trees.
250.831 Alteration or disconnection of subsea pipeline or umbilical.
250.832 Additional safety equipment—subsea trees.
250.833 Specification for underwater safety valves (USVs).
250.834 Use of USVs.
250.835 Specification for all boarding shutdown valves (BSDVs) associated with subsea systems.
250.836 Use of BSDVs.
250.837 Emergency action and safety system shutdown—subsea trees.
250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?
250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system?

PRODUCTION SAFETY SYSTEMS

250.840 Design, installation, and maintenance—general.
250.841 Platforms.
250.842 Approval of safety systems design and installation features.
250.843–250.849 [Reserved]

ADDITIONAL PRODUCTION SYSTEM REQUIREMENTS

250.850 Production system requirements—general.
250.851 Pressure vessels (including heat exchangers) and fired vessels.
250.852 Flowlines/Headers.
250.853 Safety sensors.
250.854 Floating production units equipped with turrets and turret-mounted systems.
250.855 Emergency shutdown (ESD) system.
250.856 Engines.
250.857 Glycol dehydration units.
250.858 Gas compressors.
250.859 Firefighting systems.
250.860 Chemical firefighting system.
250.861 Foam firefighting systems.
250.862 Fire and gas-detection systems.
250.863 Electrical equipment.
250.864 Erosion.
250.865 Surface pumps.
250.866 Personnel safety equipment.
250.867 Temporary quarters and temporary equipment.
250.868 Non-metallic piping.
250.869 General platform operations.
250.870 Time delays on pressure safety low (PSL) sensors.
250.871 Welding and burning practices and procedures.
250.872 Atmospheric vessels.
250.873 Subsea gas lift requirements.
250.874 Subsea water injection systems.
250.875 Subsea pump systems.
250.876 Fired and exhaust heated components.
250.877–250.879 [Reserved]

SAFETY DEVICE TESTING

250.880 Production safety system testing.
250.881–250.889 [Reserved]

RECORDS AND TRAINING

250.890 Records.
250.891 Safety device training.
250.892–250.899 [Reserved]

Subpart I—Platforms and Structures

GENERAL REQUIREMENTS FOR PLATFORMS

250.900 What general requirements apply to all platforms?
250.901 What industry standards must your platform meet?
250.902 What are the requirements for platform removal and location clearance?
250.903 What records must I keep?

PLATFORM APPROVAL PROGRAM

250.904 What is the Platform Approval Program?
250.905 How do I get approval for the installation, modification, or repair of my platform?
250.906 What must I do to obtain approval for the proposed site of my platform?
250.907 Where must I locate foundation boreholes?
250.908 What are the minimum structural fatigue design requirements?

PLATFORM VERIFICATION PROGRAM

250.909 What is the Platform Verification Program?
250.910 Which of my facilities are subject to the Platform Verification Program?
250.911 If my platform is subject to the Platform Verification Program, what must I do?
250.912 What plans must I submit under the Platform Verification Program?
250.913 When must I resubmit Platform Verification Program plans?
250.914 How do I nominate a CVA?
250.915 What are the CVA's primary responsibilities?
250.916 What are the CVA's primary duties during the design phase?
250.917 What are the CVA's primary duties during the fabrication phase?
250.918 What are the CVA's primary duties during the installation phase?

INSPECTION, MAINTENANCE, AND ASSESSMENT OF PLATFORMS

250.919 What in-service inspection requirements must I meet?
250.920 What are the BSEE requirements for assessment of fixed platforms?
250.921 How do I analyze my platform for cumulative fatigue?

Subpart J—Pipelines and Pipeline Rights-of-Way

250.1000 General requirements.
250.1001 Definitions.
250.1002 Design requirements for DOI pipelines.
250.1003 Installation, testing, and repair requirements for DOI pipelines.
250.1004 Safety equipment requirements for DOI pipelines.
250.1005 Inspection requirements for DOI pipelines.
250.1006 How must I decommission and take out of service a DOI pipeline?
250.1007 What to include in applications.
250.1008 Reports.
250.1009 Requirements to obtain pipeline right-of-way grants.
250.1010 General requirements for pipeline right-of-way holders.
250.1011 [Reserved]
250.1012 Required payments for pipeline right-of-way holders.
250.1013 Grounds for forfeiture of pipeline right-of-way grants.
250.1014 When pipeline right-of-way grants expire.
250.1015 Applications for pipeline right-of-way grants.
250.1016 Granting pipeline rights-of-way.
250.1017 Requirements for construction under pipeline right-of-way grants.
250.1018 Assignment of pipeline right-of-way grants.
250.1019 Relinquishment of pipeline right-of-way grants.

Subpart K—Oil and Gas Production Requirements

GENERAL

250.1150 What are the general reservoir production requirements?

WELL TESTS AND SURVEYS

250.1151 How often must I conduct well production tests?
250.1152 How do I conduct well tests?
250.1153 [Reserved]

CLASSIFYING RESERVOIRS

250.1154–250.1155 [Reserved]

APPROVALS PRIOR TO PRODUCTION

250.1156 What steps must I take to receive approval to produce within 500 feet of a unit or lease line?
250.1157 How do I receive approval to produce gas-cap gas from an oil reservoir with an associated gas cap?
250.1158 How do I receive approval to downhole commingle hydrocarbons?

PRODUCTION RATES

250.1159 May the Regional Supervisor limit my well or reservoir production rates?

LARING, VENTING, AND BURNING HYDROCARBONS

250.1160 When may I flare or vent gas?
250.1161 When may I flare or vent gas for extended periods of time?
250.1162 When may I burn produced liquid hydrocarbons?
250.1163 How must I measure gas flaring or venting volumes and liquid hydrocarbon burning volumes, and what records must I maintain?
250.1164 What are the requirements for flaring or venting gas containing H_2S?

OTHER REQUIREMENTS

250.1165 What must I do for enhanced recovery operations?
250.1166 What additional reporting is required for developments in the Alaska OCS Region?
250.1167 What information must I submit with forms and for approvals?

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

250.1200 Question index table.
250.1201 Definitions.
250.1202 Liquid hydrocarbon measurement.
250.1203 Gas measurement.
250.1204 Surface commingling.

250.1205 Site security.

Subpart M—Unitization

250.1300 What is the purpose of this subpart?
250.1301 What are the requirements for unitization?
250.1302 What if I have a competitive reservoir on a lease?
250.1303 How do I apply for voluntary unitization?
250.1304 How will BSEE require unitization?

Subpart N—Outer Continental Shelf Civil Penalties

OUTER CONTINENTAL SHELF LANDS ACT CIVIL PENALTIES

250.1400 How does BSEE begin the civil penalty process?
250.1401 [Reserved]
250.1402 Definitions.
250.1403 What is the maximum civil penalty?
250.1404 Which violations will BSEE review for potential civil penalties?
250.1405 When is a case file developed?
250.1406 When will BSEE notify me and provide penalty information?
250.1407 How do I respond to the letter of notification?
250.1408 When will I be notified of the Reviewing Officer's decision?
250.1409 What are my appeal rights?

FEDERAL OIL AND GAS ROYALTY MANAGEMENT ACT CIVIL PENALTIES DEFINITIONS

250.1450 What definitions apply to this subpart?

PENALTIES AFTER A PERIOD TO CORRECT

250.1451 What may BSEE do if I violate a statute, regulation, order, or lease term relating to a Federal oil and gas lease?
250.1452 What if I correct the violation?
250.1453 What if I do not correct the violation?
250.1454 How may I request a hearing on the record on a Notice of Noncompliance?
250.1455 Does my request for a hearing on the record affect the penalties?
250.1456 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

PENALTIES WITHOUT A PERIOD TO CORRECT

250.1460 May I be subject to penalties without prior notice and an opportunity to correct?
250.1461 How will BSEE inform me of violations without a period to correct?
250.1462 How may I request a hearing on the record on a Notice of Noncompliance regarding violations without a period to correct?
250.1463 Does my request for a hearing on the record affect the penalties?
250.1464 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

GENERAL PROVISIONS

250.1470 How does BSEE decide what the amount of the penalty should be?
250.1471 Does the penalty affect whether I owe interest?
250.1472 How will the Office of Hearings and Appeals conduct the hearing on the record?
250.1473 How may I appeal the Administrative Law Judge's decision?
250.1474 May I seek judicial review of the decision of the Interior Board of Land Appeals?
250.1475 When must I pay the penalty?
250.1476 Can BSEE reduce my penalty once it is assessed?
250.1477 How may BSEE collect the penalty?

CRIMINAL PENALTIES

250.1480 May the United States criminally prosecute me for violations under Federal oil and gas leases?

Subpart O—Well Control and Production Safety Training

250.1500 Definitions.
250.1501 What is the goal of my training program?
250.1503 What are my general responsibilities for training?
250.1504 May I use alternative training methods?
250.1505 Where may I get training for my employees?
250.1506 How often must I train my employees?
250.1507 How will BSEE measure training results?
250.1508 What must I do when BSEE administers written or oral tests?
250.1509 What must I do when BSEE administers or requires hands-on, simulator, or other types of testing?
250.1510 What will BSEE do if my training program does not comply with this subpart?

Subpart P—Sulphur Operations

250.1600 Performance standard.
250.1601 Definitions.
250.1602 Applicability.
250.1603 Determination of sulphur deposit.
250.1604 General requirements.
250.1605 Drilling requirements.
250.1606 Control of wells.
250.1607 Field rules.
250.1608 Well casing and cementing.
250.1609 Pressure testing of casing.

250.1610 Blowout preventer systems and system components.
250.1611 Blowout preventer systems tests, actuations, inspections, and maintenance.
250.1612 Well-control drills.
250.1613 Diverter systems.
250.1614 Mud program.
250.1615 Securing of wells.
250.1616 Supervision, surveillance, and training.
250.1617 Application for permit to drill.
250.1618 Application for permit to modify.
250.1619 Well records.
250.1620 Well-completion and well-workover requirements.
250.1621 Crew instructions.
250.1622 Approvals and reporting of well-completion and well-workover operations.
250.1623 Well-control fluids, equipment, and operations.
250.1624 Blowout prevention equipment.
250.1625 Blowout preventer system testing, records, and drills.
250.1626 Tubing and wellhead equipment.
250.1627 Production requirements.
250.1628 Design, installation, and operation of production systems.
250.1629 Additional production and fuel gas system requirements.
250.1630 Safety-system testing and records.
250.1631 Safety device training.
250.1632 Production rates.
250.1633 Production measurement.
250.1634 Site security.

Subpart Q—Decommissioning Activities

GENERAL

250.1700 What do the terms ''decommissioning'', ''obstructions'', and ''facility'' mean?
250.1701 Who must meet the decommissioning obligations in this subpart?
250.1702 When do I accrue decommissioning obligations?
250.1703 What are the general requirements for decommissioning?
250.1704 What decommissioning applications and reports must I submit and when must I submit them?
250.1705 [Reserved]
250.1706 Coiled tubing and snubbing operations.
250.1707–250.1709 [Reserved]

PERMANENTLY PLUGGING WELLS

250.1710 When must I permanently plug all wells on a lease?
250.1711 When will BSEE order me to permanently plug a well?
250.1712 What information must I submit before I permanently plug a well or zone?
250.1713 Must I notify BSEE before I begin well plugging operations?
250.1714 What must I accomplish with well plugs?
250.1715 How must I permanently plug a well?
250.1716 To what depth must I remove wellheads and casings?
250.1717 [Reserved]

TEMPORARY ABANDONED WELLS

250.1721 If I temporarily abandon a well that I plan to re-enter, what must I do?
250.1722 If I install a subsea protective device, what requirements must I meet?
250.1723 What must I do when it is no longer necessary to maintain a well in temporary abandoned status?

REMOVING PLATFORMS AND OTHER FACILITIES

250.1725 When do I have to remove platforms and other facilities?
250.1726 When must I submit an initial platform removal application and what must it include?
250.1727 What information must I include in my final application to remove a platform or other facility?
250.1728 To what depth must I remove a platform or other facility?
250.1729 After I remove a platform or other facility, what information must I submit?
250.1730 When might BSEE approve partial structure removal or toppling in place?
250.1731 Who is responsible for decommissioning an OCS facility subject to an Alternate Use RUE?

SITE CLEARANCE FOR WELLS, PLATFORMS, AND OTHER FACILITIES

250.1740 How must I verify that the site of a permanently plugged well, removed platform, or other removed facility is clear of obstructions?
250.1741 If I drag a trawl across a site, what requirements must I meet?
250.1742 What other methods can I use to verify that a site is clear?
250.1743 How do I certify that a site is clear of obstructions?

PIPELINE DECOMMISSIONING

250.1750 When may I decommission a pipeline in place?
250.1751 How do I decommission a pipeline in place?
250.1752 How do I remove a pipeline?
250.1753 After I decommission a pipeline, what information must I submit?
250.1754 When must I remove a pipeline decommissioned in place?

Subpart R [Reserved]

Subpart S—Safety and Environmental Management Systems (SEMS)

250.1900 Must I have a SEMS program?
250.1901 What is the goal of my SEMS program?
250.1902 What must I include in my SEMS program?
250.1903 Acronyms and definitions.
250.1904 Special instructions.
250.1905–250.1908 [Reserved]
250.1909 What are management's general responsibilities for the SEMS program?
250.1910 What safety and environmental information is required?
250.1911 What hazards analysis criteria must my SEMS program meet?
250.1912 What criteria for management of change must my SEMS program meet?
250.1913 What criteria for operating procedures must my SEMS program meet?
250.1914 What criteria must be documented in my SEMS program for safe work practices and contractor selection?
250.1915 What training criteria must be in my SEMS program?
250.1916 What criteria for mechanical integrity must my SEMS program meet?
250.1917 What criteria for pre-startup review must be in my SEMS program?
250.1918 What criteria for emergency response and control must be in my SEMS program?
250.1919 What criteria for investigation of incidents must be in my SEMS program?
250.1920 What are the auditing requirements for my SEMS program?
250.1921 What qualifications must the ASP meet?
250.1922 What qualifications must an AB meet?
250.1923 [Reserved]
250.1924 How will BSEE determine if my SEMS program is effective?
250.1925 May BSEE direct me to conduct additional audits?
250.1926 [Reserved]
250.1927 What happens if BSEE finds shortcomings in my SEMS program?
250.1928 What are my recordkeeping and documentation requirements?
250.1929 What are my responsibilities for submitting OCS performance measure data?
250.1930 What must be included in my SEMS program for SWA?
250.1931 What must be included in my SEMS program for UWA?
250.1932 What are my EPP requirements?
250.1933 What procedures must be included for reporting unsafe working conditions?

AUTHORITY: 30 U.S.C. 1751, 31 U.S.C. 9701, 33 U.S.C. 1321(j)(1)(C), 43 U.S.C. 1334.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

EDITORIAL NOTE: Nomenclature changes to part 250 appear at 77 FR 50891, Aug. 22, 2012.

Subpart A—General

AUTHORITY AND DEFINITION OF TERMS

§ 250.101 Authority and applicability.

The Secretary of the Interior (Secretary) authorized the Bureau of Safety and Environmental Enforcement (BSEE) to regulate oil, gas, and sulphur exploration, development, and production operations on the Outer Continental Shelf (OCS). Under the Secretary's authority, the Director requires that all operations:

(a) Be conducted according to the OCS Lands Act (OCSLA), the regulations in this part, BSEE orders, the lease or right-of-way, and other applicable laws, regulations, and amendments; and

(b) Conform to sound conservation practice to preserve, protect, and develop mineral resources of the OCS to:

(1) Make resources available to 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 receives 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.

§ 250.102 What does this part do?

(a) This part 250 contains the regulations of the BSEE Offshore program that govern oil, gas, and sulphur exploration, development, and production operations on the OCS. When you conduct operations on the OCS, you must submit requests, applications, and notices, or provide supplemental information for BSEE approval.

(b) The following table of general references shows where to look for information about these processes.

For information about . . .	Refer to . . .
(1) Applications for permit to drill,	30 CFR part 250, subpart D.
(2) Development and Production Plans (DPP),	30 CFR part 550, subpart B.
(3) Downhole commingling,	30 CFR part 250, subpart K.
(4) Exploration Plans (EP),	30 CFR part 550, subpart B.
(5) Flaring,	30 CFR part 250, subpart K.
(6) Gas measurement,	30 CFR part 250, subpart L.
(7) Off-lease geological and geophysical permits,	30 CFR part 551.
(8) Oil spill financial responsibility coverage,	30 CFR part 553.
(9) Oil and gas production safety systems,	30 CFR part 250, subpart H.
(10) Oil spill response plans,	30 CFR part 254.
(11) Oil and gas well-completion operations,	30 CFR part 250, subpart E.
(12) Oil and gas well-workover operations,	30 CFR part 250, subpart F.
(13) Decommissioning Activities,	30 CFR part 250, subpart Q.
(14) Platforms and structures,	30 CFR part 250, subpart I.
(15) Pipelines and Pipeline Rights-of-Way,	30 CFR part 250, subpart J and 30 CFR part 550, subpart J.
(16) Sulphur operations,	30 CFR part 250, subpart P.
(17) Training,	30 CFR part 250, subpart O.
(18) Unitization,	30 CFR part 250, subpart M.
(19) Safety and Environmental Management Systems (SEMS),	30 CFR part 250, subpart S.

[76 FR 64462, Oct. 18, 2011, as amended at 36148, June 6, 2016]

§ 250.103 Where can I find more information about the requirements in this part?

BSEE may issue Notices to Lessees and Operators (NTLs) that clarify, supplement, or provide more detail about certain requirements. NTLs may also outline what you must provide as required information in your various submissions to BSEE.

§ 250.104 How may I appeal a decision made under BSEE regulations?

To appeal orders or decisions issued under BSEE regulations in 30 CFR parts 250 to 282, follow the procedures in 30 CFR part 290.

§ 250.105 Definitions.

Terms used in this part will have the meanings given in the Act and as defined in this section:

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 under the provisions of the Act, any State:

(1) The laws of which are declared, under 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 according to the proposed activity, will receive oil for processing, refining, or transshipment that 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 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, under 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 that have been analyzed. Analysis may

include, but is not limited to, identification of lithologic and fossil content, core analysis, laboratory analyses of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

Ancillary activities mean those activities on your lease or unit that you:

(1) Conduct to obtain data and information to ensure proper exploration or development of your lease or unit; and

(2) Can conduct without Bureau of Ocean Energy Management (BOEM) approval of an application or permit.

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.

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.

Arctic OCS means the Beaufort Sea and Chukchi Sea Planning Areas (for more information on these areas, *see* the Proposed Final OCS Oil and Gas Leasing Program for 2012–2017 (June 2012) at *http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Five-Year-Program/2012-2017/Program-Area-Maps/index.aspx*).

Arctic OCS conditions means, for the purposes of this part, the conditions operators can reasonably expect during operations on the Arctic OCS. Such conditions, depending on the time of year, include, but are not limited to: Extreme cold, freezing spray, snow, extended periods of low light, strong winds, dense fog, sea ice, strong currents, and dangerous sea states. Remote location, relative lack of infrastructure, and the existence of subsistence hunting and fishing areas are also characteristic of the Arctic region.

Attainment area means, for any air pollutant, an area that is shown by monitored data or that 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 and safest technology (BAST) means the best available and safest technologies that the BSEE Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.

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 Regional Supervisor will verify the BACT on a case-by-case basis, and it may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

Cap and flow system means an integrated suite of equipment and vessels, including a capping stack and associated flow lines, that, when installed or positioned, is used to control the flow of fluids escaping from the well by conveying the fluids to the surface to a vessel or facility equipped to process the flow of oil, gas, and water. A cap and flow system is a high pressure system that includes the capping stack and piping necessary to convey the flowing fluids through the choke manifold to the surface equipment.

Capping stack means a mechanical device, including one that is pre-positioned, that can be installed on top of a subsea or surface wellhead or blowout preventer to stop the uncontrolled flow of fluids into the environment.

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors that 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, under 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 producible or producing well completions on each of two or more leases or portions of leases, with different lease operating interests, from which the lessees plan future production.

Containment dome means a non-pressurized container that can be used to collect fluids escaping from the well or equipment below the sea surface or from seeps by suspending the device over the discharge or seep location. The containment dome includes all of the equipment necessary to capture and convey fluids to the surface.

Correlative rights when used with respect to lessees of adjacent leases, 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, measurements, or samples that have not been analyzed, processed, or interpreted.

Departures mean approvals granted by the appropriate BSEE or BOEM representative for operating requirements/procedures other than those specified in the regulations found in this part. These requirements/procedures may be necessary to control a well; properly develop a lease; conserve natural resources, or protect life, property, or the marine, coastal, or human environment.

Development means those activities that take place following discovery of minerals in paying quantities, including but not limited to geophysical activity, drilling, platform construction, and operation of all directly related onshore support facilities, and which are for the purpose of producing the minerals discovered.

Development geological and geophysical (G&G) activities mean those G&G and related data-gathering activities on your lease or unit that you conduct following discovery of oil, gas, or sulphur in paying quantities to detect or imply the presence of oil, gas, or sulphur in commercial quantities.

Director means the Director of BSEE of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

District Manager means the BSEE officer with authority and responsibility for operations or other designated program functions for a district within a BSEE Region. For activities on the Alaska OCS, any reference in this part to District Manager means the BSEE Regional Supervisor.

Easement means an authorization for a nonpossessory, nonexclusive interest in a portion of the OCS, whether leased or unleased, which specifies the rights of the holder to use the area embraced in the easement in a manner consistent with the terms and conditions of the granting authority.

Eastern Gulf of Mexico means all OCS areas of the Gulf of Mexico the BOEM Director decides are adjacent to the State of Florida. The Eastern Gulf of Mexico is not the same as the Eastern Planning Area, an area established for OCS lease sales.

Emission offsets mean emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan (EP) or Development and Production Plan (DPP).

Enhanced recovery operations mean pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations that alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

Existing facility, as used in 30 CFR 550.303, means an OCS facility described in an Exploration Plan or a Development and Production Plan approved before June 2, 1980.

Exploration means the commercial search for oil, gas, or sulphur. Activities classified as exploration include but are not limited to:

(1) Geophysical and geological (G&G) surveys using magnetic, gravity, seismic reflection, seismic refraction, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur; and

(2) Any drilling conducted for the purpose of searching for commercial quantities of oil, gas, and sulphur, including the drilling of any additional well needed to delineate any reservoir to enable the lessee to decide whether to proceed with development and production.

Facility means:

(1) As used in § 250.130, all installations permanently or temporarily attached to the seabed on the OCS (including manmade islands and bottom-sitting structures). They include mobile offshore drilling units (MODUs) or other vessels engaged in drilling or downhole operations, used for oil, gas or sulphur drilling, production, or related activities. They include all floating production systems (FPSs), variously described as column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc*. They also include facilities for product measurement and royalty determination (e.g., lease Automatic Custody Transfer Units, gas meters) of OCS production on installations not on the OCS. Any group of OCS installations interconnected with walkways, or any group of installations that includes a central or primary installation with processing equipment and one or more satellite or secondary installations is a single facility. The Regional Supervisor may decide that the complexity of the individual installations justifies their classification as separate facilities.

(2) As used in 30 CFR 550.303, means all installations or devices permanently or temporarily attached to the seabed. They include mobile offshore drilling units (MODUs), even while operating in the ''tender assist'' mode (*i.e.*, with skid-off drilling units) or other vessels engaged in drilling or downhole operations. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc*. During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

(3) As used in § 250.490(b), means a vessel, a structure, or an artificial island used for drilling, well completion, well-workover, or production operations.

(4) As used in §§ 250.900 through 250.921, means all installations or devices permanently or temporarily attached to the seabed. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc*. During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

(5) As used in subpart S of this part, all types of structures permanently or temporarily attached to the seabed (e.g., mobile offshore drilling units (MODUs); floating production systems; floating production, storage and offloading facilities; tension-leg platforms; and spars) that are used for exploration, development, and production activities for oil, gas, or sulphur in the OCS. Facilities also include DOI-regulated pipelines.

Flaring means the burning of natural gas as it is released into the atmosphere.

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 associated gas-cap of an oil reservoir.

Geological and geophysical (G&G) explorations mean those G&G surveys on your lease or unit that use seismic reflection, seismic refraction, magnetic, gravity, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur in commercial quantities.

Governor means the Governor of a State, or the person or entity designated by, or under, State law to exercise the powers granted to such Governor under the Act.

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 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.

Human environment means the physical, social, and economic components, conditions, and factors that 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.

Interpreted geological information means geological knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of data and analyzed geological information.

Interpreted geophysical information means geophysical knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geophysical data and analyzed geophysical information.

Lease means an agreement that is issued under section 8 or maintained under section 6 of the Act and that authorizes exploration for, and development and production of, minerals. The term also means the area covered by that authorization, whichever the context requires.

Lease term pipelines mean those pipelines owned and operated by a lessee or operator that are completely contained within the boundaries of a single lease, unit, or contiguous (not cornering) leases of that lessee or operator.

Lessee means a person who has entered into a lease with the United States to explore for, develop, and produce the leased minerals. The term lessee also includes the BOEM-approved assignee of the lease, and the owner or the BOEM-approved assignee of operating rights for the lease.

Major Federal action means any action or proposal by the Secretary that is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act of 1969, 42 U.S.C. (2)(C) (*i.e.*, an action that will have a significant impact on the quality of the human environment requiring preparation of an environmental impact statement under section 102(2)(C) of the National Environmental Policy Act).

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the productivity, state, condition, and quality of the marine ecosystem. These include 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 mean 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 that 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.

Minerals include oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals that are authorized by an Act of Congress to be produced.

Natural resources include, without limiting the generality thereof, oil, gas, and all other minerals, and fish, shrimp, oysters, clams, crabs, lobsters, sponges, kelp, and other marine animal and plant life but does not include water power or the use of water for the production of power.

Nonattainment area means, for any air pollutant, an area that is shown by monitored data or that 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.

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.

Operating rights mean any interest held in a lease with the right to explore for, develop, and produce leased substances.

Operator means the person the lessee(s) designates as having control or management of operations on the leased area or a portion thereof. An operator may be a lessee, the BSEE-approved or BOEM-approved designated agent of the lessee(s), or the holder of operating rights under a BOEM-approved operating rights assignment.

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) whose subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person includes a natural person, an association (including partnerships, joint ventures, and trusts), a State, a political subdivision of a State, or a private, public, or municipal corporation.

Pipelines are the piping, risers, and appurtenances installed for transporting oil, gas, sulphur, and produced waters.

Processed geological or geophysical information means data collected under a permit or a lease that have been processed or reprocessed. Processing involves changing the form of data 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. Reprocessing is the additional processing other than ordinary processing used in the general course of evaluation. Reprocessing operations may include varying identified parameters for the detailed study of a specific problem area.

Production means those activities that 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 workover operations.

Production areas are those areas where flammable petroleum gas, volatile liquids or sulphur are produced, processed (e.g., compressed), stored, transferred (e.g., pumped), or otherwise handled before entering the transportation process.

Projected emissions mean emissions, either controlled or uncontrolled, from a source or sources.

Prospect means a geologic feature having the potential for mineral deposits.

Regional Director means the BSEE officer with responsibility and authority for a Region within BSEE.

Regional Supervisor means the BSEE officer with responsibility and authority for operations or other designated program functions within a BSEE Region.

Right-of-use means any authorization issued under 30 CFR Part 550 to use OCS lands.

Right-of-way pipelines are those pipelines that are contained within:

(1) The boundaries of a single lease or unit, but are not owned and operated by a lessee or operator of that lease or unit;

(2) The boundaries of contiguous (not cornering) leases that do not have a common lessee or operator;

(3) The boundaries of contiguous (not cornering) leases that have a common lessee or operator but are not owned and operated by that common lessee or operator; or

(4) An unleased block(s).

Routine operations, for the purposes of subpart F, mean 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 that 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;

(12) Setting and retrieving other subsurface flow-control devices; and

(13) Acid treatments.

Sensitive reservoir means a reservoir in which the production rate will affect ultimate recovery.

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, or its successor.

Source control and containment equipment (SCCE) means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels the collective purpose of which is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. ''Surface devices'' refers to equipment mounted or staged on a barge, vessel, or facility to separate, treat, store and/or dispose of fluids conveyed to the surface by the cap and flow system or the containment dome. ''Subsea devices'' includes, but is not limited to, remotely operated vehicles, anchors, buoyancy equipment, connectors, cameras, controls and other subsea equipment necessary to facilitate the deployment, operation, and retrieval of the SCCE. The SCCE does not include a blowout preventer.

Suspension means a granted or directed deferral of the requirement to produce (Suspension of Production (SOP)) or to conduct leaseholding operations (Suspension of Operations (SOO)).

Venting means the release of gas into the atmosphere without igniting it. This includes gas that is released underwater and bubbles to the atmosphere.

Waste of oil, gas, or sulphur means:

(1) The physical waste of oil, gas, or sulphur;

(2) The inefficient, excessive, or improper use, 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 that causes or tends to cause a reduction in the quantity of oil, gas, or sulphur ultimately recoverable under prudent and proper operations or that causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or

(4) The inefficient storage of oil.

Welding means all activities connected with welding, including hot tapping and burning.

Wellbay is the area on a facility within the perimeter of the outermost wellheads.

Well-completion operations mean 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.

Western Gulf of Mexico means all OCS areas of the Gulf of Mexico except those the BOEM Director decides are adjacent to the State of Florida. The Western Gulf of Mexico is not the same as the Western Planning Area, an area established for OCS lease sales.

Workover operations mean the work conducted on wells after the initial well-completion operation for the purpose of maintaining or restoring the productivity of a well.

You means a lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20439, Apr. 5, 2013; 81 FR 46560, July 15, 2016]

PERFORMANCE STANDARDS

§ 250.106 What standards will the Director use to regulate lease operations?

The Director will regulate all operations under a lease, right-of-use and easement, or right-of-way to:

(a) Promote orderly exploration, development, and production of mineral resources;

(b) Prevent injury or loss of life;

(c) Prevent damage to or waste of any natural resource, property, or the environment; and

(d) Cooperate and consult with affected States, local governments, other interested parties, and relevant Federal agencies.

§ 250.107 What must I do to protect health, safety, property, and the environment?

(a) You must protect health, safety, property, and the environment by:

(1) Performing all operations in a safe and workmanlike manner;

(2) Maintaining all equipment and work areas in a safe condition;

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

(4) Complying with all lease, plan, and permit terms and conditions.

(b) You must immediately control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

(c) *Best available and safest technology.* (1) On all new drilling and production operations and, except as provided in paragraph (c)(3) of this section, on existing operations, you must use the best available and safest technologies (BAST) which the Director determines to be economically feasible whenever the Director determines that 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.

(2) Conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required pursuant to paragraph (c)(1) of this section.

(3) The Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. The Director may waive the requirement to use BAST on an existing operation at a specific facility if you submit a waiver request demonstrating that the use of BAST would not be practicable.

(d) BSEE may issue orders to ensure compliance with this part, including, but not limited to, orders to produce and submit records and to inspect, repair, and/or replace equipment. BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26014, Apr. 29, 2016; 81 FR 61915, Sept. 7, 2016]

§ 250.108 What requirements must I follow for cranes and other material-handling equipment?

(a) All cranes installed on fixed platforms must be operated in accordance with American Petroleum Institute's Recommended Practice for Operation and Maintenance of Offshore Cranes, API RP 2D (as incorporated by reference in § 250.198).

(b) All cranes installed on fixed platforms must be equipped with a functional anti-two block device.

(c) If a fixed platform is installed after March 17, 2003, all cranes on the platform must meet the requirements of American Petroleum Institute Specification for Offshore Pedestal Mounted Cranes, API Spec 2C (as incorporated by reference in § 250.198).

(d) All cranes manufactured after March 17, 2003, and installed on a fixed platform, must meet the requirements of API Spec 2C.

(e) You must maintain records specific to a crane or the operation of a crane installed on an OCS fixed platform, as follows:

(1) Retain all design and construction records, including installation records for any anti-two block safety devices, for the life of the crane. The records must be kept at the OCS fixed platform.

(2) Retain all inspection, testing, and maintenance records of cranes for at least 4 years. The records must be kept at the OCS fixed platform.

(3) Retain the qualification records of the crane operator and all rigger personnel for at least 4 years. The records must be kept at the OCS fixed platform.

(f) You must operate and maintain all other material-handling equipment in a manner that ensures safe operations and prevents pollution.

§ 250.109 What documents must I prepare and maintain related to welding?

(a) You must submit a Welding Plan to the District Manager before you begin drilling or production activities on a lease. You may not begin welding until the District Manager has approved your plan.

(b) You must keep the following at the site where welding occurs:

(1) A copy of the plan and its approval letter; and

(2) Drawings showing the designated safe-welding areas.

§ 250.110 What must I include in my welding plan?

You must include all of the following in the welding plan that you prepare under § 250.109:

(a) Standards or requirements for welders;

(b) How you will ensure that only qualified personnel weld;

(c) Practices and procedures for safe welding that address:

(1) Welding in designated safe areas;

(2) Welding in undesignated areas, including wellbay;

(3) Fire watches;

(4) Maintenance of welding equipment; and

(5) Plans showing all designated safe-welding areas.

(d) How you will prevent spark-producing activities (*i.e.*, grinding, abrasive blasting/cutting and arc-welding) in hazardous locations.

§ 250.111 Who oversees operations under my welding plan?

A welding supervisor or a designated person in charge must be thoroughly familiar with your welding plan. This person must ensure that each welder is properly qualified according to the welding plan. This person also must inspect all welding equipment before welding.

§ 250.112 What standards must my welding equipment meet?

Your welding equipment must meet the following requirements:

(a) All engine-driven welding equipment must be equipped with spark arrestors and drip pans;

(b) Welding leads must be completely insulated and in good condition;

(c) Hoses must be leak-free and equipped with proper fittings, gauges, and regulators; and

(d) Oxygen and fuel gas bottles must be secured in a safe place.

§ 250.113 What procedures must I follow when welding?

(a) Before you weld, you must move any equipment containing hydrocarbons or other flammable substances at least 35 feet horizontally from the welding area. You must move similar equipment on lower decks at least 35 feet from the point of impact where slag, sparks, or other burning materials could fall. If moving this equipment is impractical, you must protect that equipment with flame-proofed covers, shield it with metal or fire-resistant guards or curtains, or render the flammable substances inert.

(b) While you weld, you must monitor all water-discharge-point sources from hydrocarbon-handling vessels. If a discharge of flammable fluids occurs, you must stop welding.

(c) If you cannot weld in one of the designated safe-welding areas that you listed in your safe welding plan, you must meet the following requirements:

(1) You may not begin welding until:

(i) The welding supervisor or designated person in charge advises in writing that it is safe to weld.

(ii) You and the designated person in charge inspect the work area and areas below it for potential fire and explosion hazards.

(2) During welding, the person in charge must designate one or more persons as a fire watch. The fire watch must:

(i) Have no other duties while actual welding is in progress;

(ii) Have usable firefighting equipment;

(iii) Remain on duty for 30 minutes after welding activities end; and

(iv) Maintain a continuous surveillance with a portable gas detector during the welding and burning operation if welding occurs in an area not equipped with a gas detector.

(3) You may not weld piping, containers, tanks, or other vessels that have contained a flammable substance unless you have rendered the contents inert and the designated person in charge has determined it is safe to weld. This does not apply to approved hot taps.

(4) You may not weld within 10 feet of a wellbay unless you have shut in all producing wells in that wellbay.

(5) You may not weld within 10 feet of a production area, unless you have shut in that production area.

(6) You may not weld while you drill, complete, workover, or conduct wireline operations unless:

(i) The fluids in the well (being drilled, completed, worked over, or having wireline operations conducted) are noncombustible; and

(ii) You have precluded the entry of formation hydrocarbons into the wellbore by either mechanical means or a positive overbalance toward the formation.

§ 250.114 How must I install, maintain, and operate electrical equipment?

The requirements in this section apply to all electrical equipment on all platforms, artificial islands, fixed structures, and their facilities.

(a) You must classify all areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2 (as incorporated by reference in § 250.198), or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (as incorporated by reference in § 250.198).

(b) Employees who maintain your electrical systems must have expertise in area classification and the performance, operation and hazards of electrical equipment.

(c) You must install all electrical systems according to API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1, and Division 2 Locations (as incorporated by reference in § 250.198), or API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1, and Zone 2 Locations (as incorporated by reference in § 250.198).

(d) On each engine that has an electric ignition system, you must use an

ignition system designed and maintained to reduce the release of electrical energy.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36149, June 6, 2016]

§ 250.115 What are the procedures for, and effects of, incorporation of documents by reference in this part?

For the documents incorporated by reference in this part:

(a) Incorporation by reference of a document is limited to the edition of the document, or the specific edition and supplement or addendum, that is cited in § 250.198. Future amendments or revisions of the incorporated document are not included. BSEE will publish any changes to the incorporation of the document in the FEDERAL REGISTER and amend § 250.198 as appropriate.

(b) BSEE may make a rule amending the incorporation of a document effective without prior opportunity for public comment when BSEE determines:

(1) That the revisions to the document result in safety improvements or represent new industry standard technology and do not impose undue costs on the affected parties; and

(2) BSEE meets the requirements for making a rule immediately effective under 5 U.S.C. 553.

(c) The effect of incorporation by reference of a document into the regulations in this part is that the incorporated document is a requirement. When a section in this part refers to an incorporated document, you are responsible for complying with the provisions of that entire document, except to the extent that the section that refers to the document provides otherwise. When a section in this part refers to a part of an incorporated document, you are responsible for complying with that part of the document as provided in that section.

(d) Under §§ 250.141 and 250.142, you may comply with a later edition of a specific document incorporated by reference, provided:

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

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

[84 FR 21968, May 15, 2019]

§§ 250.116–250.117 [Reserved]

GAS STORAGE OR INJECTION

§ 250.118 Will BSEE approve gas injection?

The Regional Supervisor may authorize you to inject gas on the OCS, on and off-lease, to promote conservation of natural resources and to prevent waste.

(a) To receive BSEE approval for injection, you must:

(1) Show that the injection will not result in undue interference with operations under existing leases; and

(2) Submit a written application to the Regional Supervisor for injection of gas.

(b) The Regional Supervisor will approve gas injection applications that:

(1) Enhance recovery;

(2) Prevent flaring of casinghead gas; or

(3) Implement other conservation measures approved by the Regional Supervisor.

§ 250.119 [Reserved]

§ 250.120 How does injecting, storing, or treating gas affect my royalty payments?

(a) If you produce gas from an OCS lease and inject it into a reservoir on the lease or unit for the purposes cited in § 250.118(b), you are not required to pay royalties until you remove or sell the gas from the reservoir.

(b) If you produce gas from an OCS lease and store it according to 30 CFR 550.119, you must pay royalty before injecting it into the storage reservoir.

(c) If you produce gas from an OCS lease and treat it at an off-lease or off-unit location, you must pay royalties when the gas is first produced.

§ 250.121 What happens when the reservoir contains both original gas in place and injected gas?

If the reservoir contains both original gas in place and injected gas, when you produce gas from the reservoir you must use a BSEE-approved formula to

determine the amounts of injected or stored gas and gas original to the reservoir.

§ 250.122 What effect does subsurface storage have on the lease term?

If you use a lease area for subsurface storage of gas, it does not affect the continuance or expiration of the lease.

§ 250.123 [Reserved]

§ 250.124 Will BSEE approve gas injection into the cap rock containing a sulphur deposit?

To receive the Regional Supervisor's approval to inject gas into the cap rock of a salt dome containing a sulphur deposit, you must show that the injection:

(a) Is necessary to recover oil and gas contained in the cap rock; and

(b) Will not significantly increase potential hazards to present or future sulphur mining operations.

FEES

§ 250.125 Service fees.

(a) The table in this paragraph (a) shows the fees that you must pay to BSEE for the services listed. The fees will be adjusted periodically according to the Implicit Price Deflator for Gross Domestic Product by publication of a document in the FEDERAL REGISTER. If a significant adjustment is needed to arrive at the new actual cost for any reason other than inflation, then a proposed rule containing the new fees will be published in the FEDERAL REGISTER for comment.

Service—processing of the following:	Fee amount	30 CFR citation
(1) Suspension of Operations/Suspension of Production (SOO/SOP) Request.	$2,469	§ 250.171(e).
(2) Deepwater Operations Plan (DWOP).	$4,186	§ 250.292(q).
(3) Application for Permit to Drill (APD; Form BSEE–0123).	$2,458 for initial applications only; no fee for revisions.	§ 250.410(d); § 250.513(b); § 250.1617(a).
(4) Application for Permit to Modify (APM; Form BSEE–0124).	$145	§ 250.465(b); § 250.513(b); § 250.613(b); § 250.1618(a); § 250.1704(g).
(5) New Facility Production Safety System Application for facility with more than 125 components.	$6,312 A $16,610 additional fee will be charged if BSEE conducts a pre-production inspection of a facility offshore, and $8,638 for an inspection of a facility while in a shipyard. A component is a piece of equipment or ancillary system that is protected by one or more of the safety devices required by API RP 14C (as incorporated by reference in § 250.198).	§ 250.842.
(6) New Facility Production Safety System Application for facility with 25–125 components.	$1,528 A $10,430 additional fee will be charged if BSEE conducts a pre-production inspection of a facility offshore, and $5,980 for an inspection of a facility while in a shipyard.	§ 250.842.
(7) New Facility Production Safety System Application for facility with fewer than 25 components.	$758	§ 250.842.
(8) Production Safety System Application—Modification with more than 125 components reviewed.	$704	§ 250.842.

Service—processing of the following:	Fee amount	30 CFR citation
(9) Production Safety System Application—Modification with 25–125 components reviewed.	$252	§ 250.842.
(10) Production Safety System Application—Modification with fewer than 25 components reviewed.	$107	§ 250.842.
(11) Platform Application—Installation—Under the Platform Verification Program.	$26,444	§ 250.905(l).
(12) Platform Application—Installation—Fixed Structure Under the Platform Approval Program.	$3,787	§ 250.905(l).
(13) Platform Application—Installation—Caisson/Well Protector.	$1,927	§ 250.905(l).
(14) Platform Application—Modification/Repair.	$4,518	§ 250.905(l).
(15) New Pipeline Application (Lease Term).	$4,119	§ 250.1000(b).
(16) Pipeline Application—Modification (Lease Term).	$2,392	§ 250.1000(b).
(17) Pipeline Application—Modification (ROW).	$4,849	§ 250.1000(b).
(18) Pipeline Repair Notification	$451	§ 250.1008(e).
(19) Pipeline Right-of-Way (ROW) Grant Application.	$3,223	§ 250.1015(a).
(20) Pipeline Conversion of Lease Term to ROW.	$275	§ 250.1015(a).
(21) Pipeline ROW Assignment	$234	§ 250.1018(b).
(22) 500 Feet from Lease/Unit Line Production Request.	$4,527	§ 250.1156(a).
(23) Gas Cap Production Request	$5,761	§ 250.1157(b).
(24) Downhole Commingling Request.	$6,722	§ 250.1158(a).
(25) Complex Surface Commingling and Measurement Application.	$4,718	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(26) Simple Surface Commingling and Measurement Application.	$1,595	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(27) Voluntary Unitization Proposal or Unit Expansion.	$14,678	§ 250.1303(d).
(28) Unitization Revision	$1,042	§ 250.1303(d).
(29) Application to Remove a Platform or Other Facility.	$5,448	§ 250.1727.
(30) Application to Decommission a Pipeline (Lease Term).	$1,328	§ 250.1751(a) or § 250.1752(a).
(31) Application to Decommission a Pipeline (ROW).	$2,524	§ 250.1751(a) or § 250.1752(a).

(b) Payment of the fees listed in paragraph (a) of this section must accompany the submission of the document for approval or be sent to an office identified by the Regional Director. Once a fee is paid, it is nonrefundable, even if an application or other request is withdrawn. If your application is returned to you as incomplete, you are not required to submit a new fee when you submit the amended application.

(c) Verbal approvals are occasionally given in special circumstances. Any action that will be considered a verbal permit approval requires either a paper permit application to follow the verbal approval or an electronic application submittal within 72 hours. Payment

must be made with the completed paper or electronic application.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50891, Aug. 22, 2012; 78 FR 60213, Oct. 1, 2013; 81 FR 26014, Apr. 29, 2016; 81 FR 61916, Sept. 7, 2016; 87 FR 19803, Apr. 6, 2022]

§ 250.126 Electronic payment instructions.

(a) You must file all payments electronically through the Fees for Services Page on the BSEE website at *https://www.bsee.gov/who-we-are/working-with-us/Fees-for-Services*. This includes, but is not limited to, all OCS applications, permits, or any filing fees. You must include a copy of the *Pay.gov* confirmation receipt page with your application, permit, or filing fee.

(b) If you submitted an application or permit through eWell, you must use the interactive payment feature in that system, which directs you through *Pay.gov* to make a payment. It is recommended that you keep a copy of your payment confirmation receipt in the event that any questions arise regarding your transaction.

[81 FR 36149, June 6, 2016; as amended at 87 FR 19803, Apr. 6, 2022]

INSPECTIONS OF OPERATIONS

§ 250.130 Why does BSEE conduct inspections?

BSEE will inspect OCS facilities and any vessels engaged in drilling or other downhole operations. These include facilities under jurisdiction of other Federal agencies that we inspect by agreement. We conduct these inspections:

(a) To verify that you are conducting operations according to the Act, the regulations, the lease, right-of-way, the BOEM-approved Exploration Plan or Development and Production Plans; or right-of-use and easement, and other applicable laws and regulations; and

(b) To determine whether equipment designed to prevent or ameliorate blowouts, fires, spillages, or other major accidents has been installed and is operating properly according to the requirements of this part.

§ 250.131 Will BSEE notify me before conducting an inspection?

BSEE conducts both scheduled and unscheduled inspections.

§ 250.132 What must I do when BSEE conducts an inspection?

(a) When BSEE conducts an inspection, you must provide:

(1) Access to all platforms, artificial islands, and other installations on your leases or associated with your lease, right-of-use and easement, or right-of-way; and

(2) Helicopter landing sites and refueling facilities for any helicopters we use to regulate offshore operations.

(b) You must make the following available for us to inspect:

(1) The area covered under a lease, right-of-use and easement, right-of-way, or permit;

(2) All improvements, structures, and fixtures on these areas; and

(3) All records of design, construction, operation, maintenance, repairs, or investigations on or related to the area.

§ 250.133 Will BSEE reimburse me for my expenses related to inspections?

Upon request, BSEE will reimburse you for food, quarters, and transportation that you provide for BSEE representatives while they inspect lease facilities and operations. You must send us your reimbursement request within 90 days of the inspection.

DISQUALIFICATION

§ 250.135 What will BSEE do if my operating performance is unacceptable?

BSEE will determine if your operating performance is unacceptable. BSEE will refer a determination of unacceptable performance to BOEM, who may disapprove or revoke your designation as operator on a single facility or multiple facilities. We will give you adequate notice and opportunity for a review by BSEE officials before making a determination that your operating performance is unacceptable.

§ 250.136 How will BSEE determine if my operating performance is unacceptable?

In determining if your operating performance is unacceptable, BSEE will consider, individually or collectively:

(a) Accidents and their nature;

(b) Pollution events, environmental damages and their nature;

(c) Incidents of noncompliance;

(d) Civil penalties;

(e) Failure to adhere to OCS lease obligations; or

(f) Any other relevant factors.

SPECIAL TYPES OF APPROVALS

§ 250.140 When will I receive an oral approval?

When you apply for BSEE approval of any activity, we normally give you a written decision. The following table shows circumstances under which we may give an oral approval.

When you . . .	We may . . .	And . . .
(a) Request approval orally	Give you an oral approval,	You must then confirm the oral request by sending us a written request within 72 hours.
(b) Request approval in writing,	Give you an oral approval if quick action is needed,	We will send you a written approval afterward. It will include any conditions that we place on the oral approval.
(c) Request approval orally for gas flaring,	Give you an oral approval,	You don't have to follow up with a written request unless the Regional Supervisor requires it. When you stop the approved flaring, you must promptly send a letter summarizing the location, dates and hours, and volumes of liquid hydrocarbons produced and gas flared by the approved flaring (see 30 CFR 250, subpart K).

§ 250.141 May I ever use alternate procedures or equipment?

You may use alternate procedures or equipment after receiving approval as described in this section.

(a) Any alternate procedures or equipment that you propose to use must provide a level of safety and environmental protection that equals or surpasses current BSEE requirements.

(b) You must receive the District Manager's or Regional Supervisor's written approval before you can use alternate procedures or equipment.

(c) To receive approval, you must either submit information or give an oral presentation to the appropriate Regional Supervisor. Your presentation must describe the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment.

§ 250.142 How do I receive approval for departures?

We may approve departures to the operating requirements. You may apply for a departure by writing to the District Manager or Regional Supervisor.

§§ 250.143–250.144 [Reserved]

§ 250.145 How do I designate an agent or a local agent?

(a) You or your designated operator may designate for the Regional Supervisor's approval, or the Regional Director may require you to designate an agent empowered to fulfill your obligations under the Act, the lease, or the regulations in this part.

(b) You or your designated operator may designate for the Regional Supervisor's approval a local agent empowered to receive notices and submit requests, applications, notices, or supplemental information.

§ 250.146 Who is responsible for fulfilling leasehold obligations?

(a) When you are not the sole lessee, you and your co-lessee(s) are jointly and severally responsible for fulfilling your obligations under the provisions of 30 CFR parts 250 through 282 and 30 CFR parts 550 through 582 unless otherwise provided in these regulations.

(b) If your designated operator fails to fulfill any of your obligations under 30 CFR parts 250 through 282 and 30 CFR parts 550 through 582, the Regional Supervisor may require you or any or all of your co-lessees to fulfill those obligations or other operational obligations under the Act, the lease, or the regulations.

(c) Whenever the regulations in 30 CFR parts 250 through 282 and 30 CFR parts 550 through 582 require the lessee to meet a requirement or perform an action, the lessee, operator (if one has been designated), and the person actually performing the activity to which the requirement applies are jointly and

severally responsible for complying with the regulation.

NAMING AND IDENTIFYING FACILITIES AND WELLS (DOES NOT INCLUDE MODUS)

§ 250.150 How do I name facilities and wells in the Gulf of Mexico Region?

(a) Assign each facility a letter designation except for those types of facilities identified in paragraph (c)(1) of this section. For example, A, B, CA, or CB.

(1) After a facility is installed, rename each predrilled well that was assigned only a number and was suspended temporarily at the mudline or at the surface. Use a letter and number designation. The letter used must be the same as that of the production facility, and the number used must correspond to the order in which the well was completed, not necessarily the number assigned when it was drilled. For example, the first well completed for production on Facility A would be renamed Well A–1, the second would be Well A–2, and so on; and

(2) When you have more than one facility on a block, each facility installed, and not bridge-connected to another facility, must be named using a different letter in sequential order. For example, EC 222A, EC 222B, EC 222C.

(3) When you have more than one facility on multiple blocks in a local area being co-developed, each facility installed and not connected with a walkway to another facility should be named using a different letter in sequential order with the block number corresponding to the block on which the platform is located. For example, EC 221A, EC 222B, and EC 223C.

(b) In naming multiple well caissons, you must assign a letter designation.

(c) In naming single well caissons, you must use certain criteria as follows:

(1) For single well caissons not attached to a facility with a walkway, use the well designation. For example, Well No. 1;

(2) For single well caissons attached to a facility with a walkway, use the same designation as the facility. For example, rename Well No.10 as A–10; and

(3) For single well caissons with production equipment, use a letter designation for the facility name and a letter plus number designation for the well. For example, the Well No. 1 caisson would be designated as Facility A, and the well would be Well A–1.

§ 250.151 How do I name facilities in the Pacific Region?

The operator assigns a name to the facility.

§ 250.152 How do I name facilities in the Alaska Region?

Facilities will be named and identified according to the Regional Director's directions.

§ 250.153 Do I have to rename an existing facility or well?

You do not have to rename facilities installed and wells drilled before January 27, 2000, unless the Regional Director requires it.

§ 250.154 What identification signs must I display?

(a) You must identify all facilities, artificial islands, and mobile offshore drilling units with a sign maintained in a legible condition.

(1) You must display an identification sign that can be viewed from the waterline on at least one side of the platform. The sign must use at least 3-inch letters and figures.

(2) When helicopter landing facilities are present, you must display an additional identification sign that is visible from the air. The sign must use at least 12-inch letters and figures and must also display the weight capacity of the helipad unless noted on the top of the helipad. If this sign is visible to both helicopter and boat traffic, then the sign in paragraph (a)(1) of this section is not required.

(3) Your identification sign must:

(i) List the name of the lessee or designated operator;

(ii) In the GOM OCS Region, list the area designation or abbreviation and the block number of the facility location as depicted on OCS Official Protraction Diagrams or leasing maps;

(iii) In the Pacific OCS Region, list the lease number on which the facility is located; and

(iv) List the name of the platform, structure, artificial island, or mobile offshore drilling unit.

(b) You must identify singly completed wells and multiple completions as follows:

(1) For each singly completed well, list the lease number and well number on the wellhead or on a sign affixed to the wellhead;

(2) For wells with multiple completions, downhole splitter wells, and multilateral wells, identify each completion in addition to the well name and lease number individually on the well flowline at the wellhead; and

(3) For subsea wells that flow individually into separate pipelines, affix the required sign on the pipeline or surface flowline dedicated to that subsea well at a convenient location on the receiving platform. For multiple subsea wells that flow into a common pipeline or pipelines, no sign is required.

§§ 250.160–250.167 [Reserved]

SUSPENSIONS

§ 250.168 May operations or production be suspended?

(a) You may request approval of a suspension, or the Regional Supervisor may direct a suspension (Directed Suspension), for all or any part of a lease or unit area.

(b) Depending on the nature of the suspended activity, suspensions are labeled either Suspensions of Operations (SOO) or Suspensions of Production (SOP).

§ 250.169 What effect does suspension have on my lease?

(a) A suspension may extend the term of a lease (see § 250.180(b), (d), and (e)). The extension is equal to the length of time the suspension is in effect, except as provided in paragraph (b) of this section.

(b) A Directed Suspension does not extend the term of a lease when the Regional Supervisor *directs* a suspension because of:

(1) Gross negligence; or

(2) A willful violation of a provision of the lease or governing statutes and regulations.

§ 250.170 How long does a suspension last?

(a) BSEE may issue suspensions for up to 5 years per suspension. The Regional Supervisor will set the length of the suspension based on the conditions of the individual case involved. BSEE may grant consecutive suspension periods.

(b) An SOO ends automatically when the suspended operation commences.

(c) An SOP ends automatically when production begins.

(d) A Directed Suspension normally ends as specified in the letter directing the suspension.

(e) BSEE may terminate any suspension when the Regional Supervisor determines the circumstances that justified the suspension no longer exist or that other lease conditions warrant termination. The Regional Supervisor will notify you of the reasons for termination and the effective date.

§ 250.171 How do I request a suspension?

You must submit your request for a suspension to the Regional Supervisor, and BSEE must receive the request before the end of the lease term (*i.e.*, end of primary term, end of the 1-year period following the last leaseholding operation, and end of a current suspension). Your request must include:

(a) The justification for the suspension including the length of suspension requested;

(b) A reasonable schedule of work leading to the commencement or restoration of the suspended activity;

(c) A statement that a well has been drilled on the lease and determined to be producible according to § 250.1603 (SOP only), 30 CFR 550.115, or 30 CFR 550.116;

(d) A commitment to production (SOP only); and

(e) The service fee listed in § 250.125 of this subpart.

[76 FR 64462, Oct. 18, 2011, as amended at 82 FR 26744, June 9, 2017]

§ 250.172 When may the Regional Supervisor grant or direct an SOO or SOP?

The Regional Supervisor may grant or direct an SOO or SOP under any of the following circumstances:

(a) When necessary to comply with judicial decrees prohibiting any activities or the permitting of those activities. The effective date of the suspension will be the effective date required by the action of the court;

(b) When activities pose a threat of serious, irreparable, or immediate harm or damage. This would include a threat to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment. BSEE may require you to do a site-specific study (see § 250.177(a)).

(c) When necessary for the installation of safety or environmental protection equipment;

(d) When necessary to carry out the requirements of NEPA or to conduct an environmental analysis; or

(e) When necessary to allow for inordinate delays encountered in obtaining required permits or consents, including administrative or judicial challenges or appeals.

§ 250.173 When may the Regional Supervisor direct an SOO or SOP?

The Regional Supervisor may direct a suspension when:

(a) You failed to comply with an applicable law, regulation, order, or provision of a lease or permit; or

(b) The suspension is in the interest of National security or defense.

§ 250.174 When may the Regional Supervisor grant or direct an SOP?

The Regional Supervisor may grant or direct an SOP when the suspension is in the National interest, and it is necessary because the suspension will meet one of the following criteria:

(a) It will allow you to properly develop a lease, including time to construct and install production facilities;

(b) It will allow you time to obtain adequate transportation facilities;

(c) It will allow you time to enter a sales contract for oil, gas, or sulphur. You must show that you are making an effort to enter into the contract(s); or

(d) It will avoid continued operations that would result in premature abandonment of a producing well(s).

§ 250.175 When may the Regional Supervisor grant an SOO?

(a) The Regional Supervisor may grant an SOO when necessary to allow you time to begin drilling or other operations when you are prevented by reasons beyond your control, such as unexpected weather, unavoidable accidents, or drilling rig delays.

(b) The Regional Supervisor may grant an SOO when all of the following conditions are met:

(1) The lease was issued with a primary lease term of 5 years, or with a primary term of 8 years with a requirement to drill within 5 years;

(2) Before the end of the third year of the primary term, you or your predecessor in interest must have acquired and interpreted geophysical information that indicates:

(i) The presence of a salt sheet;

(ii) That all or a portion of a potential hydrocarbon-bearing formation may lie beneath or adjacent to the salt sheet; and

(iii) The salt sheet interferes with identification of the potential hydrocarbon-bearing formation.

(3) The interpreted geophysical information required under paragraph (b)(2) of this section must include full 3–D depth migration beneath the salt sheet and over the entire lease area.

(4) Before requesting the suspension, you have conducted or are conducting additional data processing or interpretation of the geophysical information with the objective of identifying a potential hydrocarbon-bearing formation.

(5) You demonstrate that additional time is necessary to:

(i) Complete current processing or interpretation of existing geophysical data or information;

(ii) Acquire, process, or interpret new geophysical data or information; or

(iii) Drill into the potential hydrocarbon-bearing formation identified as a result of the activities conducted in paragraphs (b)(2), (b)(4), and (b)(5) of this section.

(c) The Regional Supervisor may grant an SOO to conduct additional geological and geophysical data analysis that may lead to the drilling of a well below 25,000 feet true vertical depth below the datum at mean sea level

(TVD SS) when all of the following conditions are met:

(1) The lease was issued with a primary lease term of:

(i) Five years; or

(ii) Eight years with a requirement to drill within 5 years.

(2) Before the end of the fifth year of the primary term, you or your predecessor in interest must have acquired and interpreted geophysical information that:

(i) Indicates that all or a portion of a potential hydrocarbon-bearing formation lies below 25,000 feet TVD SS; and

(ii) Includes full 3–D depth migration over the entire lease area.

(3) Before requesting the suspension, you have conducted or are conducting additional data processing or interpretation of the geophysical information with the objective of identifying a potential hydrocarbon-bearing geologic structure or stratigraphic trap lying below 25,000 feet TVD SS.

(4) You demonstrate that additional time is necessary to:

(i) Complete current processing or interpretation of existing geophysical data or information;

(ii) Acquire, process, or interpret new geophysical or geological data or information that would affect the decision to drill the same geologic structure or stratigraphic trap, as determined by the Regional Supervisor, identified in paragraphs (c)(2) and (c)(3) of this section; or

(iii) Drill a well below 25,000 feet TVD SS into the geologic structure or stratigraphic trap identified as a result of the activities conducted in paragraphs (c)(2), (c)(3), and (c)(4)(i) and (ii) of this section.

§ 250.176 Does a suspension affect my royalty payment?

A directed suspension may affect the payment of rental or royalties for the lease as provided in 30 CFR 1218.154.

§ 250.177 What additional requirements may the Regional Supervisor order for a suspension?

If BSEE grants or directs a suspension under paragraph § 250.172(b), the Regional Supervisor may require you to:

(a) Conduct a site-specific study.

(1) The Regional Supervisor must approve or prescribe the scope for any site-specific study that you perform.

(2) The study must evaluate the cause of the hazard, the potential damage, and the available mitigation measures.

(3) You must pay for the study unless you request, and the Regional Supervisor agrees to arrange, payment by another party.

(4) You must furnish copies and results of the study to the Regional Supervisor.

(5) BSEE will make the results available to other interested parties and to the public.

(6) The Regional Supervisor will use the results of the study and any other information that becomes available:

(i) To decide if the suspension can be lifted; and

(ii) To determine any actions that you must take to mitigate or avoid any damage to the environment, life, or property.

(b) Submit a revised Exploration Plan (including any required mitigating measures);

(c) Submit a revised Development and Production Plan (including any required mitigating measures); or

(d) Submit a revised Development Operations Coordination Document according to 30 CFR part 550, subpart B.

PRIMARY LEASE REQUIREMENTS, LEASE TERM EXTENSIONS, AND LEASE CANCELLATIONS

§ 250.180 What am I required to do to keep my lease term in effect?

(a) If your lease is in its primary term:

(1) You must submit a report to the District Manager according to paragraphs (h) and (i) of this section whenever production begins initially, whenever production ceases during the last year of the primary term, and whenever production resumes during the last year of the primary term.

(2) Your lease expires at the end of its primary term unless you are conducting operations on your lease (see 30 CFR part 556). For purposes of this section, the term *operations* means, drilling, well-reworking, or production in paying quantities. The objective of the drilling or well-reworking must be to

establish production in paying quantities on the lease.

(b) If you stop conducting operations during the last year of your primary lease term, your lease will expire unless you either resume operations or receive an SOO or an SOP from the Regional Supervisor under § 250.172, § 250.173, § 250.174, or § 250.175 before the end of the year after you stop operations.

(c) If you extend your lease term under paragraph (b) of this section, you must pay rental or minimum royalty, as appropriate, for each year or part of the year during which your lease continues in force beyond the end of the primary lease term.

(d) If you stop conducting operations on a lease that has continued beyond its primary term, your lease will expire unless you resume operations or receive an SOO or an SOP from the Regional Supervisor under § 250.172, § 250.173, § 250.174, or § 250.175 before the end of the year after you stop operations.

(e) You may ask the Regional Supervisor to allow you more than a year 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 it conserves resources, prevents waste, or protects correlative rights.

(f) When you begin conducting operations on a lease that has continued beyond its primary term, you must immediately notify the District Manager either orally or by fax or e-mail and follow up with a written report according to paragraph (g) of this section.

(g) If your lease is continued beyond its primary term, you must submit a report to the District Manager under paragraphs (h) and (i) of this section whenever production begins initially, whenever production ceases, whenever production resumes before the end of the 1-year period after having ceased, or whenever drilling or well-reworking operations begin before the end of the 1-year period.

(h) The reports required by paragraphs (a) and (g) of this section must contain:

(1) Name of lessee or operator;

(2) The well number, lease number, area, and block;

(3) As appropriate, the unit agreement name and number; and

(4) A description of the operation and pertinent dates.

(i) You must submit the reports required by paragraphs (a) and (g) of this section within the following timeframes:

(1) Initialization of production—within 5 days of initial production.

(2) Cessation of production—within 15 days after the first full month of zero production.

(3) Resumption of production—within 5 days of resuming production after ceasing production under paragraph (i)(2) of this section.

(4) Drilling or well reworking operations—within 5 days of beginning and completing the leaseholding operations.

(j) For leases continued beyond the primary term, you must immediately report to the District Manager if operations do not begin before the end of the 1-year period.

[76 FR 64462, Oct. 18, 2011, as amended at 82 FR 26744, June 9, 2017]

§§ 250.181–250.185 [Reserved]

INFORMATION AND REPORTING REQUIREMENTS

§ 250.186 What reporting information and report forms must I submit?

(a) You must submit information and reports as BSEE requires.

(1) You may obtain copies of forms from, and submit completed forms to, the District Manager or Regional Supervisor.

(2) Instead of paper copies of forms available from the District Manager or Regional Supervisor, you may use your own computer-generated forms that are equal in size to BSEE's forms. You must arrange the data on your form identical to the BSEE form. If you generate your own form and it omits terms and conditions contained on the official BSEE form, we will consider it

to contain the omitted terms and conditions.

(3) You may submit digital data when the Region/District is equipped to accept it.

(b) When BSEE specifies, you must include, for public information, an additional copy of such reports.

(1) You must mark it *Public Information*

(2) You must include all required information, except information exempt from public disclosure under § 250.197 or otherwise exempt from public disclosure under law or regulation.

§ 250.187 What are BSEE's incident reporting requirements?

(a) You must report all incidents listed in § 250.188(a) and (b) to the District Manager. The specific reporting requirements for these incidents are contained in §§ 250.189 and 250.190.

(b) These reporting requirements apply to incidents that occur on the area covered by your lease, right-of-use and easement, pipeline right-of-way, or other permit issued by BOEM or BSEE, and that are related to operations resulting from the exercise of your rights under your lease, right-of-use and easement, pipeline right-of-way, or permit.

(c) Nothing in this subpart relieves you from making notifications and reports of incidents that may be required by other regulatory agencies.

(d) You must report all spills of oil or other liquid pollutants in accordance with 30 CFR 254.46.

§ 250.188 What incidents must I report to BSEE and when must I report them?

(a) You must report the following incidents to the District Manager immediately via oral communication, and provide a written follow-up report (hard copy or electronically transmitted) within 15 calendar days after the incident:

(1) All fatalities.

(2) All injuries that require the evacuation of the injured person(s) from the facility to shore or to another offshore facility.

(3) All losses of well control. ''Loss of well control'' means:

(i) Uncontrolled flow of formation or other fluids. The flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout);

(ii) Flow through a diverter; or

(iii) Uncontrolled flow resulting from a failure of surface equipment or procedures.

(4) All fires and explosions.

(5) All reportable releases of hydrogen sulfide (H_2S) gas, as defined in § 250.490(l).

(6) All collisions that result in property or equipment damage greater than $25,000. ''Collision'' means the act of a moving vessel (including an aircraft) striking another vessel, or striking a stationary vessel or object (e.g., a boat striking a drilling rig or platform). ''Property or equipment damage'' means the cost of labor and material to restore all affected items to their condition before the damage, including, but not limited to, the OCS facility, a vessel, helicopter, or equipment. It does not include the cost of salvage, cleaning, gas-freeing, dry docking, or demurrage.

(7) All incidents involving structural damage to an OCS facility. ''Structural damage'' means damage severe enough so that operations on the facility cannot continue until repairs are made.

(8) All incidents involving crane or personnel/material handling operations.

(9) All incidents that damage or disable safety systems or equipment (including firefighting systems).

(b) You must provide a written report of the following incidents to the District Manager within 15 calendar days after the incident:

(1) Any injuries that result in one or more days away from work or one or more days on restricted work or job transfer. One or more days means the injured person was not able to return to work or to all of their normal duties the day after the injury occurred;

(2) All gas releases that initiate equipment or process shutdown;

(3) All incidents that require operations personnel on the facility to muster for evacuation for reasons not related to weather or drills;

(4) All other incidents, not listed in paragraph (a) of this section, resulting in property or equipment damage greater than $25,000.

(c) On the Arctic OCS, in addition to the requirements of paragraphs (a) and (b) of this section, you must provide to the BSEE inspector on location, if one is present, or to the Regional Supervisor, both of the following:

(1) An immediate oral report if any of the following occur:

(i) Any sea ice movement or condition that has the potential to affect your operation or trigger ice management activities;

(ii) The start and termination of ice management activities; or

(iii) Any ''kicks'' or operational issues that are unexpected and could result in the loss of well control.

(2) Within 24 hours after completing ice management activities, a written report of such activities that conforms to the content requirements in § 250.190.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 46560, July 15, 2016]

§ 250.189 Reporting requirements for incidents requiring immediate notification.

For an incident requiring immediate notification under § 250.188(a), you must notify the District Manager via oral communication immediately after aiding the injured and stabilizing the situation. Your oral communication must provide the following information:

(a) Date and time of occurrence;

(b) Operator, and operator representative's, name and telephone number;

(c) Contractor, and contractor representative's name and telephone number (if a contractor is involved in the incident or injury/fatality);

(d) Lease number, OCS area, and block;

(e) Platform/facility name and number, or pipeline segment number;

(f) Type of incident or injury/fatality;

(g) Operation or activity at time of incident (*i.e.*, drilling, production, workover, completion, pipeline, crane, *etc.*); and

(h) Description of the incident, damage, or injury/fatality.

§ 250.190 Reporting requirements for incidents requiring written notification.

(a) For any incident covered under § 250.188, you must submit a written report within 15 calendar days after the incident to the District Manager. The report must contain the following information:

(1) Date and time of occurrence;

(2) Operator, and operator representative's name and telephone number;

(3) Contractor, and contractor representative's name and telephone number (if a contractor is involved in the incident or injury);

(4) Lease number, OCS area, and block;

(5) Platform/facility name and number, or pipeline segment number;

(6) Type of incident or injury;

(7) Operation or activity at time of incident (*i.e.*, drilling, production, workover, completion, pipeline, crane *etc.*);

(8) Description of incident, damage, or injury (including days away from work, restricted work or job transfer), and any corrective action taken; and

(9) Property or equipment damage estimate (in U.S. dollars).

(b) You may submit a report or form prepared for another agency in lieu of the written report required by paragraph (a) of this section, provided the report or form contains all required information.

(c) The District Manager may require you to submit additional information about an incident on a case-by-case basis.

§ 250.191 How does BSEE conduct incident investigations?

Any investigation that BSEE conducts under the authority of sections 22(d)(1) and (2) of the Act (43 U.S.C. 1348(d)(1) and (2)) is a fact-finding proceeding with no adverse parties. The purpose of the investigation is to prepare a public report that determines the cause or causes of the incident. The investigation may involve panel meetings conducted by a chairperson appointed by BSEE. The following requirements apply to any panel meetings involving persons giving testimony:

(a) A person giving testimony may have legal or other representative(s) present to provide advice or counsel while the person is giving testimony. The chairperson may require a verbatim transcript to be made of all oral testimony. The chairperson also may

accept a sworn written statement in lieu of oral testimony.

(b) Only panel members, and any experts the panel deems necessary, may address questions to any person giving testimony.

(c) The chairperson may issue subpoenas to persons to appear and provide testimony or documents at a panel meeting. A subpoena may not require a person to attend a panel meeting held at a location more than 100 miles from where a subpoena is served.

(d) Any person giving testimony may request compensation for mileage, and fees for services, within 90 days after the panel meeting. The compensated expenses must be similar to mileage and fees the U.S. District Courts allow.

§ 250.192 What reports and statistics must I submit relating to a hurricane, earthquake, or other natural occurrence?

(a) You must submit evacuation statistics to the Regional Supervisor for a natural occurrence, such as a hurricane, a tropical storm, or an earthquake. Statistics include facilities and rigs evacuated and the amount of production shut-in for gas and oil. You must:

(1) Submit the statistics by fax or e-mail (for activities in the BSEE GOM OCS Region, use Form BSEE–0132) as soon as possible when evacuation occurs. In lieu of submitting your statistics by fax or e-mail, you may submit them electronically in accordance with 30 CFR 250.186(a)(3);

(2) Submit the statistics on a daily basis by 11 a.m., as conditions allow, during the period of shut-in and evacuation;

(3) Inform BSEE when you resume production; and

(4) Submit the statistics either by BSEE district, or the total figures for your operations in a BSEE region.

(b) If your facility, production equipment, or pipeline is damaged by a natural occurrence, you must:

(1) Submit an initial damage report to the Regional Supervisor within 48 hours after you complete your initial evaluation of the damage. You must use Form BSEE–0143, Facility/Equipment Damage Report, to make this and all subsequent reports. In lieu of submitting Form BSEE–0143 by fax or e-mail, you may submit the damage report electronically in accordance with 30 CFR 250.186(a)(3). In the report, you must:

(i) Name the items damaged (e.g., platform or other structure, production equipment, pipeline);

(ii) Describe the damage and assess the extent of the damage (major, medium, minor); and

(iii) Estimate the time it will take to replace or repair each damaged structure and piece of equipment and return it to service. The initial estimate need not be provided on the form until availability of hardware and repair capability has been established (not to exceed 30 days from your initial report).

(2) Submit subsequent reports monthly and immediately whenever information submitted in previous reports changes until the damaged structure or equipment is returned to service. In the final report, you must provide the date the item was returned to service.

§ 250.193 Reports and investigations of possible violations.

(a) Any person may report to BSEE any hazardous or unsafe working condition on any facility engaged in OCS activities, and any possible violation or failure to comply with:

(1) Any provision of the Act,

(2) Any provision of a lease, approved plan, or permit issued under the Act,

(3) Any provision of any regulation or order issued under the Act, or

(4) Any other Federal law relating to safety of offshore oil and gas operations.

(b) To make a report under this section, a person is not required to know whether any legal requirement listed in paragraph (a) of this section has been violated.

(c) When BSEE receives a report of a possible violation, or when a BSEE employee detects a possible violation, BSEE will investigate according to BSEE procedures and notify any other Federal agency(ies) for further investigation, as appropriate.

(d) BSEE investigations of possible violations may include:

(1) Conducting interviews of personnel;

(2) Requiring the prompt production of documents, data, and other evidence;

(3) Requiring the preservation of all relevant evidence and access for BSEE investigators to such evidence; and

(4) Taking other actions and imposing other requirements as necessary to investigate possible violations and assure an orderly investigation.

(e)(1) Reports should contain sufficient credible information to establish a reasonable basis for BSEE to investigate whether a violation or other hazardous or unsafe working condition exists.

(2) To report hazardous or unsafe working conditions or a possible violation:

(i) Contact BSEE by:

(A) Phone at 1–877–440–0173 (BSEE Toll-free Safety Hotline),

(B) Internet at *www.bsee.gov*, or

(C) Mail to: U.S. DOI/BSEE, 1849 C Street NW., Mail Stop 5438, Washington, DC 20240 Attention: IRU Hotline Operations.

(ii) Include the following items in the report:

(A) Name, address, and telephone number should be provided if you do not want to remain anonymous;

(B) The specific concern, provision or Federal law, if known, referenced in (a) that a person violated or with which a person failed to comply; and

(C) Any other facts, data, and applicable information.

(f) When a possible violation is reported, BSEE will protect a person's identity to the extent authorized by law.

[78 FR 20439, Apr. 5, 2013, as amended at 81 FR 36149, June 6, 2016]

§ 250.194 How must I protect archaeological resources?

(a)–(b) [Reserved]

(c) If you discover any archaeological resource while conducting operations in the lease or right-of-way area, you must immediately halt operations within the area of the discovery and report the discovery to the BSEE Regional Director. If investigations determine that the resource is significant, the Regional Director will tell you how to protect it.

§ 250.195 What notification does BSEE require on the production status of wells?

You must notify the appropriate BSEE District Manager when you successfully complete or recomplete a well for production. You must:

(a) Notify the District Manager within 5 working days of placing the well in a production status. You must confirm oral notification by telefax or e-mail within those 5 working days.

(b) Provide the following information in your notification:

(1) Lessee or operator name;

(2) Well number, lease number, and OCS area and block designations;

(3) Date you placed the well on production (indicate whether or not this is first production on the lease);

(4) Type of production; and

(5) Measured depth of the production interval.

§ 250.196 Reimbursements for reproduction and processing costs.

(a) BSEE will reimburse you for costs of reproducing data and information that the Regional Director requests if:

(1) You deliver geophysical and geological (G&G) data and information to BSEE for the Regional Director to inspect or select and retain;

(2) BSEE receives your request for reimbursement and the Regional Director determines that the requested reimbursement is proper; and

(3) The cost is at your lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) BSEE will reimburse you for the costs of processing geophysical information (that does not include cost of data acquisition):

(1) If, at the request of the Regional Director, you processed the geophysical data or information in a form or manner other than that used in the normal conduct of business; or

(2) If you collected the information under a permit that BSEE issued to you before October 1, 1985, and the Regional Director requests and retains the information.

(c) When you request reimbursement, you must identify reproduction and processing costs separately from acquisition costs.

(d) BSEE will not reimburse you for data acquisition costs or for the costs of analyzing or processing geological information or interpreting geological or geophysical information.

§ 250.197 Data and information to be made available to the public or for limited inspection.

BSEE will protect data and information that you submit under this part, and 30 CFR part 203, as described in this section. Paragraphs (a) and (b) of this section describe what data and information will be made available to the public without the consent of the lessee, under what circumstances, and in what time period. Paragraph (c) of this section describes what data and information will be made available for limited inspection without the consent of the lessee, and under what circumstances.

(a) All data and information you submit on BSEE forms will be made available to the public upon submission, except as specified in the following table:

On form . . .	Data and information not immediately available are . . .	Excepted data will be made available . . .
(1) BSEE–0123, Application for Permit to Drill,	Items 15, 16, 22 through 25,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(2) BSEE–0123S, Supplemental APD Information Sheet,	Items 3, 7, 8, 15 and 17,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(3) BSEE–0124, Application for Permit to Modify,	Item 17,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(4) BSEE–0125, End of Operations Report,	Items 12, 13, 17, 21, 22, 26 through 38,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier. However, items 33 through 38 will not be released when the well goes on production unless the period of time in the table in paragraph (b) has expired.
(5) BSEE–0126, Well Potential Test Report,	Item 101,	2 years after you submit it.
(6) [Reserved]		
(7) BSEE–0133 Well Activity Report,	Item 10 Fields [WELLBORE START DATE, TD DATE, OP STATUS, END DATE, MD, TVD, AND MW PPG]. Item 11 Fields [WELLBORE START DATE, TD DATE, PLUGBACK DATE, FINAL MD, AND FINAL TVD] and Items 12 through 15,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(8) BSEE–0133S Open Hole Data Report,	Boxes 7 and 8,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(9) [Reserved]		
(10) [Reserved]		

(b) BSEE will release lease and permit data and information that you submit and BSEE retains, but that are not normally submitted on BSEE forms, according to the following table:

If . . .	BSEE will release . . .	At this time . . .	Special provisions . . .
(1) The Director determines that data and information are needed for specific scientific or research purposes for the Government,	Geophysical data, Geological data Interpreted G&G information, Processed G&G information, Analyzed geological information,	At any time,	BSEE will release data and information only if release would further the National interest without unduly damaging the competitive position of the lessee.

If . . .	BSEE will release . . .	At this time . . .	Special provisions . . .
(2) Data or information is collected with high-resolution systems (e.g., bathymetry, side-scan sonar, subbottom profiler, and magnetometer) to comply with safety or environmental protection requirements,	Geophysical data, Geological data, Interpreted G&G information, Processed geological information, Analyzed geological information,	60 days after BSEE receives the data or information, if the Regional Supervisor deems it necessary,	BSEE will release the data and information earlier than 60 days if the Regional Supervisor determines it is needed by affected States to make decisions under 30 CFR 550, subpart B. The Regional Supervisor will reconsider earlier release if you satisfy him/her that it would unduly damage your competitive position.
(3) Your lease is no longer in effect,	Geophysical data, Geological data, Processed G&G information Interpreted G&G information, Analyzed geological information,	When your lease terminates,	This release time applies only if the provisions in this table governing high-resolution systems and the provisions in 30 CFR 552.7 do not apply. The release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.
(4) Your lease is still in effect,	Geophysical data, Processed geophysical information, Interpreted G&G information,	10 years after you submit the data and information,	This release time applies only if the provisions in this table governing high-resolution systems and the provisions in 30 CFR 552.7 do not apply. This release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.
(5) Your lease is still in effect and within the primary term specified in the lease,	Geological data, Analyzed geological information,	2 years after the required submittal date or 60 days after a lease sale if any portion of an offered lease is within 50 miles of a well, whichever is later,	These release times apply only if the provisions in this table governing high-resolution systems and the provisions in 30 CFR 552.7 do not apply. If the primary term specified in the lease is extended under the heading of ''Suspensions'' in this subpart, the extension applies to this provision.
(6) Your lease is in effect and beyond the primary term specified in the lease,	Geological data, Analyzed geological information,	2 years after the required submittal date,	None.
(7) Data or information is submitted on well operations,	Descriptions of downhole locations, operations, and equipment,	When the well goes on production or when geological data is released according to §§ 250.197(b)(5) and (b)(6), whichever occurs earlier,	Directional survey data may be released earlier to the owner of an adjacent lease according to Subpart D of this part.
(8) Data and information are obtained from beneath unleased land as a result of a well deviation that has not been approved by the District Manager or Regional Supervisor,	Any data or information obtained,	At any time,	None.
(9) Except for high-resolution data and information released under paragraph (b)(2) of this section data and information acquired by a permit under 30 CFR part 551 are submitted by a lessee under 30 CFR part 203, 30 CFR part 250, or 30 CFR part 550,	G&G data, analyzed geological information, processed and interpreted G&G information,	Geological data and information: 10 years after BOEM issues the permit; Geophysical data: 50 years after BOEM issues the permit; Geophysical information: 25 years after BOEM issues the permit,	None.

(c) BSEE may allow limited inspection, but only by persons with a direct interest in related BSEE decisions and issues in specific geographic areas, and who agree in writing to its confidentiality, of G&G data and information submitted under this part or 30 CFR part 203 that BSEE uses to:

(1) Make unitization determinations on two or more leases;

(2) Make competitive reservoir determinations;

(3) Ensure proper plans of development for competitive reservoirs;

(4) Promote operational safety;

(5) Protect the environment;

(6) [Reserved]; or

(7) Determine eligibility for royalty relief.

REFERENCES

§ 250.198 Documents incorporated by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All incorporated material is available for inspection at the Houston BSEE office at 1919 Smith Street Suite 14042, Houston, Texas 77002 and is available from the sources indicated in this section. It is also available for inspection at the National Archives and Records Administration (NARA). To make an appointment to inspect incorporated material at the Houston BSEE office, call 1–844–259–4779. For information on the availability of this material at NARA, call 202–741–6030 or go to *http://www.archives.gov/federal-register/cfr/ibr-locations.html*.

(a) American Concrete Institute (ACI), ACI Standards, 38800 Country Club Drive, Farmington Hills, MI 48331–3439: *http://www.concrete.org;* phone: 248–848–3700:

(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete, 1995; incorporated by reference at § 250.901.

(2) ACI 318R–95, Commentary on Building Code Requirements for Reinforced Concrete, 1995; incorporated by reference at § 250.901.

(3) ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997, incorporated by reference at § 250.901.

(b) American Gas Association (AGA Reports), 400 North Capitol Street NW, Suite 450, Washington, DC 20001, *http://www.aga.org;* phone: 202–824–7000;

(1) AGA Report No. 7—Measurement of Natural Gas by Turbine Meters; Revised February 2006; incorporated by reference at § 250.1203(b);

(2) AGA Report No. 9—Measurement of Gas by Multipath Ultrasonic Meters; Second Edition, April 2007; incorporated by reference at § 250.1203(b);

(3) AGA Report No. 10—Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases; Copyright 2003; incorporated by reference at § 250.1203(b).

(c) American Institute of Steel Construction, Inc. (AISC), AISC Standards, One East Wacker Drive, Suite 700, Chicago, IL 60601–1802; *http://www.aisc.org;* phone: 312–670–2400:

(1) ANSI/AISC 360–05, Specification for Structural Steel Buildings, incorporated by reference at § 250.901.

(2) [Reserved]

(d) American National Standards Institute (ANSI), *http.www./webstore.ansi.org/;* phone: 212–642–4900:

(1) ANSI/ASME B 16.5–2003, Pipe Flanges and Flanged Fittings, incorporated by reference at § 250.1002;

(2) ANSI/ASME B 31.8–2003, Gas Transmission and Distribution Piping Systems, incorporated by reference at § 250.1002;

(3) ANSI Z88.2–1992, American National Standard for Respiratory Protection, incorporated by reference at § 250.490.

(e) American Petroleum Institute (API), API Recommended Practices (RP), Specs, Standards, Manual of Petroleum Measurement Standards (MPMS) chapters, 1220 L Street, NW, Washington, DC 20005–4070; *http://www.api.org;* phone: 202–682–8000:

(1) API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Tenth Edition, May 2014; Addendum 1, May 2017; incorporated by reference at §§ 250.851(a) and 250.1629(b);

(2) API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems,

Fourth Edition, February 2016; Addendum 1, May 2017; incorporated by reference at § 250.841(b).

(3) API Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, May 2007; incorporated by reference at § 250.901;

(4) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, May 2007; incorporated by reference at § 250.901;

(5) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, May 2007; incorporated by reference at § 250.901;

(6) API Bulletin 92L, Drilling Ahead Safely with Lost Circulation in the Gulf of Mexico, First Edition, August 2015; incorporated by reference at § 250.427(b);

(7) API MPMS Chapter 1—Vocabulary, Second Edition, July 1994; incorporated by reference at § 250.1201;

(8) API MPMS Chapter 2—Tank Calibration, Section 2A—Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method, First Edition, February 1995; reaffirmed August 2017; incorporated by reference at § 250.1202;

(9) API MPMS Chapter 2—Tank Calibration, Section 2B—Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989; reaffirmed April 2019 (including Addendum 1, October 2019); incorporated by reference at § 250.1202;

(10) API MPMS Chapter 3—Tank Gauging, Section 1A—Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; incorporated by reference at § 250.1202;

(11) API MPMS Chapter 3—Tank Gauging, Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition, June 2001; reaffirmed February 2016; incorporated by reference at § 250.1202;

(12) API MPMS Chapter 4—Proving Systems, Section 1—Introduction, Third Edition, February 2005; reaffirmed June 2014; incorporated by reference at § 250.1202;

(13) API MPMS Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003; incorporated by reference at § 250.1202;

(14) API MPMS Chapter 4—Proving Systems, Section 4—Tank Provers, Second Edition, May 1998, reaffirmed May 2015; incorporated by reference at § 250.1202;

(15) API MPMS Chapter 4—Proving Systems, Section 5—Master-Meter Provers, Second Edition, May 2000, reaffirmed, August 2005; incorporated by reference at § 250.1202;

(16) API MPMS Chapter 4—Proving Systems, Section 6—Pulse Interpolation, Second Edition, May 1999; Errata April 2007; reaffirmed October 2013; incorporated by reference at § 250.1202;

(17) API MPMS Chapter 4—Proving Systems, Section 7—Field Standard Test Measures, Second Edition, December 1998; reaffirmed 2003; incorporated by reference at § 250.1202;

(18) API MPMS Chapter 4—Proving Systems, Section 8—Operation of Proving Systems; First Edition, reaffirmed March 2007; incorporated by reference at § 250.1202(a), (f), and (g);

(19) API MPMS Chapter 5—Metering, Section 1—General Considerations for Measurement by Meters, Fourth Edition, September 2005; incorporated by reference at § 250.1202;

(20) API MPMS Chapter 5—Metering, Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters, Third Edition, September 2005; reaffirmed July 2015; incorporated by reference at § 250.1202;

(21) API MPMS Chapter 5—Metering, Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters, Fifth Edition, September 2005; reaffirmed August 1, 2014; incorporated by reference at § 250.1202;

(22) API MPMS Chapter 5—Metering, Section 4—Accessory Equipment for Liquid Meters, Fourth Edition, September 2005; reaffirmed August 2015; incorporated by reference at § 250.1202;

(23) API MPMS Chapter 5—Metering, Section 5—Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, Second Edition, August 2005; reaffirmed August 2015; incorporated by reference at § 250.1202;

(24) API MPMS Chapter 5—Metering, Section 6—Measurement of Liquid Hydrocarbons by Coriolis Meters; First Edition, October 2002; reaffirmed November 2013; incorporated by reference at § 250.1202;

(25) API MPMS Chapter 5—Metering, Section 8—Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters Using Transit Time Technology; First Edition, February 2005; incorporated by reference at § 250.1202(a);

(26) API MPMS Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991; reaffirmed May 2012; incorporated by reference at § 250.1202;

(27) API MPMS Chapter 6—Metering Assemblies, Section 6—Pipeline Metering Systems, Second Edition, May 1991; reaffirmed December 2017; incorporated by reference at § 250.1202;

(28) API MPMS Chapter 6—Metering Assemblies, Section 7—Metering Viscous Hydrocarbons, Second Edition, May 1991; reaffirmed March 2018; incorporated by reference at § 250.1202;

(29) API MPMS Chapter 7—Temperature Determination, First Edition, June 2001; reaffirmed, March 2007; incorporated by reference at § 250.1202;

(30) API MPMS Chapter 8—Sampling, Section 1—Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; reaffirmed, March 2006; incorporated by reference at § 250.1202;

(31) API MPMS Chapter 8—Sampling, Section 2—Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products, Second Edition, October 1995; reaffirmed, June 2005; incorporated by reference at § 250.1202;

(32) API MPMS Chapter 9—Density Determination, Section 1—Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, Second Edition, December 2002; reaffirmed October 2005; incorporated by reference at § 250.1202(a) and (l);

(33) API MPMS Chapter 9—Density Determination, Section 2—Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer, Second Edition, March 2003; incorporated by reference at § 250.1202;

(34) API MPMS Chapter 10—Sediment and Water, Section 1—Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method, Third Edition, November 2007; reaffirmed October 2012; incorporated by reference at § 250.1202;

(35) API MPMS Chapter 10—Sediment and Water, Section 2—Standard Test Method for Water in Crude Oil by Distillation, Second Edition, November 2007; incorporated by reference at § 250.1202;

(36) API MPMS Chapter 10—Sediment and Water, Section 3—Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), Third Edition, May 2008; incorporated by reference at § 250.1202;

(37) API MPMS Chapter 10—Sediment and Water, Section 4—Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure), Third Edition, December 1999; incorporated by reference at § 250.1202;

(38) API MPMS Chapter 10—Sediment and Water, Section 9—Standard Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration, Second Edition, December 2002; reaffirmed 2005; incorporated by reference at § 250.1202;

(39) API 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 Volume to 60 °F Against API Gravity at 60 °F, API Standard 2540, First Edition, August 1980; reaffirmed March 1997; incorporated by reference at § 250.1202;

(40) API 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: December 2007; incorporated by reference at § 250.1202;

(41) API MPMS Chapter 11—Physical Properties Data, Section 1—Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils; May 2004 (incorporating Addendum 1,

September 2007); incorporated by reference at § 250.1202(a), (g), and (l);

(42) API MPMS Chapter 11—Physical Properties Data, Addendum to Section 2, Part 2—Compressibility Factors for Hydrocarbons, Correlation of Vapor Pressure for Commercial Natural Gas Liquids, First Edition, December 1994; reaffirmed, December 2002; incorporated by reference at § 250.1202;

(43) API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 1—Introduction, Second Edition, May 1995; reaffirmed March 2014; incorporated by reference at § 250.1202;

(44) API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2—Measurement Tickets, Third Edition, June 2003; reaffirmed February 2016; incorporated by reference at § 250.1202;

(45) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 3—Proving Reports; First Edition, October 1998, reaffirmed March 2014; incorporated by reference at § 250.1202(a) and (g);

(46) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 4—Calculation of Base Prover Volumes by the Waterdraw Method, First Edition, December 1997; reaffirmed September 2014; incorporated by reference at § 250.1202(a), (f), and (g);

(47) API 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; reaffirmed, January 2003; incorporated by reference at § 250.1203;

(48) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters, Part 2—Specification and Installation Requirements, Fourth Edition, April 2000; reaffirmed March 2006; incorporated by reference at § 250.1203;

(49) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters; Part 3—Natural Gas Applications; Third Edition, August 1992; Errata March 1994, reaffirmed, February 2009; incorporated by reference at § 250.1203;

(50) API MPMS, Chapter 14.5/GPA Standard 2172–09; Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer; Third Edition, January 2009; reaffirmed February 2014; incorporated by reference at § 250.1203;

(51) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 6—Continuous Density Measurement, Second Edition, April 1991; reaffirmed, February 2006; incorporated by reference at § 250.1203;

(52) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 8—Liquefied Petroleum Gas Measurement, Second Edition, July 1997; reaffirmed, March 2006; incorporated by reference at § 250.1203;

(53) API MPMS Chapter 20—Section 1—Allocation Measurement, First Edition, September 1993; reaffirmed October 2006; incorporated by reference at § 250.1202;

(54) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 1—Electronic Gas Measurement, First Edition, August 1993; reaffirmed, July 2005; incorporated by reference at § 250.1203;

(55) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 2—Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters; First Edition, June 1998; reaffirmed October 2016; incorporated by reference at § 250.1202(a);

(56) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Addendum to Section 2—Flow Measurement Using Electronic Metering Systems, Inferred Mass; First Edition, reaffirmed February 2006; incorporated by reference at § 250.1202(a);

(57) API RP 2A–WSD, Recommended Practice for Planning, Designing and

Constructing Fixed Offshore Platforms—Working Stress Design, Twenty-first Edition, December 2000; Errata and Supplement 1, December 2002; Errata and Supplement 2, September 2005; Errata and Supplement 3, October 2007; incorporated by reference at §§ 250.901, 250.908, 250.919, and 250.920;

(58) API RP 2D, Operation and Maintenance of Offshore Cranes, Sixth Edition, May 2007; incorporated by reference at § 250.108;

(59) API RP 2FPS, RP for Planning, Designing, and Constructing Floating Production Systems; First Edition, March 2001; incorporated by reference at § 250.901;

(60) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Structures; Third Edition, April 2008; incorporated by reference at § 250.901(a) and (d);

(61) ANSI/API RP 2N, Third Edition, ''Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions'', Third Edition, April 2015; incorporated by reference at § 250.470(g);

(62) API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009; incorporated by reference at §§ 250.733, 250.800(c), 250.901(a), (d), and 250.1002(b);

(63) API RP 2SK, Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008, reaffirmed June 2015; incorporated by reference at §§ 250.800(c) and 250.901(a) and (d);

(64) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007; incorporated by reference at §§ 250.800(c) and 250.901(a) and (d);

(65) API RP 2T, Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms, Second Edition, August 1997; incorporated by reference at § 250.901(a) and (d);

(66) ANSI/API RP 14B, Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems, Sixth Edition, September 2015; incorporated by reference at §§ 250.802(b), 250.803(a), 250.814(d), 250.828(c), and 250.880(c);

(67) API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, reaffirmed: March 2007; incorporated by reference at §§ 250.125(a), 250.292(j), 250.841(a), 250.842(a), 250.850, 250.852(a), 250.855, 250.856(a), 250.858(a), 250.862(e), 250.865(a), 250.867(a), 250.869(a) through (c), 250.872(a), 250.873(a), 250.874(a), 250.880(b) and (c), 250.1002(d), 250.1004(b), 250.1628(c) and (d), 250.1629(b), and 250.1630(a);

(68) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; reaffirmed, January 2013; incorporated by reference at §§ 250.841(b), 250.842(a), and 250.1628(b) and (d);

(69) API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, reaffirmed: April 2013; incorporated by reference at §§ 250.114(c), 250.842(c), 250.862(e), and 250.1629(b);

(70) API RP 14FZ, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, Second Edition, May 2013; incorporated by reference at §§ 250.114(c), 250.842(c), 250.862(e), and 250.1629(b);

(71) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; Reaffirmed, January 2013; incorporated by reference at §§ 250.859(a), 250.862(e), 250.880(c), and 250.1629(b);

(72) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; reaffirmed: January 2013; incorporated by reference at §§ 250.800(b) and (c), 250.842(c), and 250.901(a) and (d);

(73) API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, Second Edition, June 2013; Errata, January 2014; incorporated by reference at § 250.734(a);

(74) API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deepwater Wells, First Edition, September 2002; incorporated by reference at § 250.415;

(75) API RP 75, Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, Third Edition, May 2004, reaffirmed May 2008; incorporated by reference at §§ 250.1900, 250.1902, 250.1903, 250.1909, 250.1920;

(76) API RP 86, API Recommended Practice for Measurement of Multiphase Flow; First Edition, September 2005; incorporated by reference at §§ 250.1202(a) and 250.1203(b);

(77) API RP 90, Annular Casing Pressure Management for Offshore Wells, First Edition, August 2006; incorporated by reference at § 250.519;

(78) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Third Edition, December 2012; Errata January 2014, incorporated by reference at §§ 250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);

(79) API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997; reaffirmed, August 2013; incorporated by reference at §§ 250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);

(80) API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993; reaffirmed November 2003; incorporated by reference at § 250.1202;

(81) API Spec. 2C, Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004; incorporated by reference at § 250.108;

(82) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition, October 2010; Addendum 1, November 2011; Errata 2, November 2011; Addendum 2, November 2012; Addendum 3, March 2013; Errata 3, June 2013; Errata 4, August 2013; Errata 5, November 2013; Errata 6, March 2014; Errata 7, December 2014; Errata 8, February 2016; Addendum 4, June 2016; Errata 9, June 2016; Errata 10, August 2016; incorporated by reference at §§ 250.730, 250.802(a), 250.803(a), 250.833, 250.873(b), 250.874(g), and 250.1002(b);

(83) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, Second Edition, February 2013; incorporated by reference at §§ 250.802(a), 250.833, 250.873(b), and 250.874(g);

(84) API STD 6AV2, Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore; First Edition, March 2014; Errata 1, August 2014; incorporated by reference at §§ 250.820, 250.834, 250.836, and 250.880(c)

(85) ANSI/API Spec. 6D, Specification for Pipeline Valves, Twenty-third Edition, April 2008; Effective Date: October 1, 2008, Errata 1, June 2008; Errata 2, November 2008; Errata 3, February 2009; Addendum 1, October 2009; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 14313:2007 (Identical), Petroleum and natural gas industries—Pipeline transportation systems—Pipeline valves; incorporated by reference at § 250.1002(b);

(86) ANSI/API Spec. 11D1, Packers and Bridge Plugs, Second Edition, July 2009; incorporated by reference at §§ 250.518, 250.619, and 250.1703;

(87) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, reaffirmed, June 2012; incorporated by reference at §§ 250.802 and 250.803(a);

(88) ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004, reaffirmed August 2010; incorporated by reference at § 250.730;

(89) ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993, reaffirmed July 2010; incorporated by reference at § 250.730;

(90) API Spec. 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004, reaffirmed August 2013; incorporated by reference at § 250.730;

(91) ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition, May 2011; incorporated by reference at § 250.730;

(92) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008, incorporated by reference at §§ 250.852(e), 250.1002(b), and 250.1007(a).

(93) ANSI/API Spec. Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition, June 2013; Errata, February 2014; Errata 2, March 2014; Addendum 1, June 2016; incorporated by reference at §§ 250.730 and 250.801(b) and (c);

(94) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, Addendum 1, July 2016, incorporated by reference at §§ 250.730, 250.734, 250.735, 250.736, 250.737, and 250.739;

(95) API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010; incorporated by reference at §§ 250.415(f) and 250.420(a);

(96) API Standard 2552, USA Standard Method for Measurement and Calibration of Spheres and Spheroids, First Edition, 1966; reaffirmed, October 2007; incorporated by reference at § 250.1202;

(97) API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002; incorporated by reference at § 250.1202;

(f) American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007–2900; *http://www.asme.org;* phone: 1–800–843–2763.

(1) 2017 ASME Boiler and Pressure Vessel Code (BPVC), Section I, Rules for Construction of Power Boilers, 2017 Edition, July 1, 2017, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(2) 2017 ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers, 2017 Edition, July 1, 2017, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(3) 2017 ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Division 1, 2017 Edition; July 1, 2017, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(4) 2017 ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Division 2: Alternative Rules, 2017 Edition, July 1, 2017, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(5) 2017 ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Division 3: Alternative Rules for Construction of High Pressure Vessels, 2017 Edition, July 1, 2017, incorporated by reference at §§ 250.851(a) and 250.1629(b).

(g) American Society for Testing and Materials (ASTM), ASTM Standards, 100 Bar Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428–2959; *http://www.astm.org;* phone: 1–877–909–2786:

(1) ASTM Standard C 33–07, approved December 15, 2007, Standard Specification for Concrete Aggregates; incorporated by reference at § 250.901;

(2) ASTM Standard C 94/C 94M–07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete; incorporated by reference at § 250.901;

(3) ASTM Standard C 150–07, approved May 1, 2007, Standard Specification for Portland Cement; incorporated by reference at § 250.901;

(4) ASTM Standard C 330–05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete; incorporated by reference at § 250.901;

(5) ASTM Standard C 595–08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements; incorporated by reference at § 250.901;

(h) American Welding Society (AWS), AWS Codes, 8669 NW 36 Street, #130, Miami, FL 33126; *http://www.aws.org;*phone: 800–443–9353:

(1) AWS D1.1:2000, Structural Welding Code—Steel, 17th Edition, October 18, 1999; incorporated by reference at § 250.901;

(2) AWS D1.4–98, Structural Welding Code—Reinforcing Steel, 1998 Edition; incorporated by reference at § 250.901;

(3) AWS D3.6M:1999, Specification for Underwater Welding (1999); incorporated by reference at § 250.901.

(i) National Association of Corrosion Engineers (NACE) International, NACE Standards, Park Ten Place, Houston, TX 77084; *http://www.nace.org;* phone: 281–228–6200:

(1) NACE Standard MR0175–2003, Standard Material Requirements, Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments, Revised January 17, 2003; incorporated by reference at §§ 250.490 and 250.901;

(2) NACE Standard RP0176–2003, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production; incorporated by reference at § 250.901.

(j) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, CP 56, CH–1211, Geneva 20, Switzerland; *www.iso.org;* phone: 41–22–749–01–11:

(1) ISO/IEC (International Electrotechnical Commission) 17011, Conformity assessment—General requirements for accreditation bodies accrediting conformity assessment bodies, First edition 2004–09–01; Corrected version 2005–02–15; incorporated by reference at §§ 250.1900, 250.1903, 250.1904, and 250.1922.

(2) ISO/IEC 17021–1, Conformity assessment—Requirements for bodies providing audit and certification of management systems—Part 1: Requirements, First Edition, June 2015, incorporated by reference at § 250.730(d).

(3) [Reserved]

(k) Center for Offshore Safety (COS), 1990 Post Oak Blvd., Suite 1370, Houston, TX 77056; *www.centerforoffshoresafety.org;* phone: 832–495–4925.

(1) COS Safety Publication COS–2–01, Qualification and Competence Requirements for Audit Teams and Auditors Performing Third-party SEMS Audits of Deepwater Operations, First Edition, Effective Date October 2012; incorporated by reference at §§ 250.1900, 250.1903, 250.1904, and 250.1921.

(2) COS Safety Publication COS–2–03, Requirements for Third-party SEMS Auditing and Certification of Deepwater Operations, First Edition, Effective Date October 2012; incorporated by reference at §§ 250.1900, 250.1903, 250.1904, and 250.1920.

(3) COS Safety Publication COS–2–04, Requirements for Accreditation of Audit Service Providers Performing SEMS Audits and Certification of Deepwater Operations, First Edition, Effective Date October 2012; incorporated by reference at §§ 250.1900, 250.1903, 250.1904, and 250.1922.

[84 FR 21969, May 15, 2019, as amended at 85 FR 84236, Dec. 30, 2020]

§ 250.199 Paperwork Reduction Act statements—information collection.

(a) OMB has approved the information collection requirements in part 250 under 44 U.S.C. 3501 *et seq.* The table in paragraph (e) of this section lists the subpart in the rule requiring the information and its title, provides the OMB control number, and summarizes the reasons for collecting the information and how BSEE uses the information. The associated BSEE forms required by this part are listed at the end of this table with the relevant information.

(b) Respondents are OCS oil, gas, and sulphur lessees and operators. The requirement to respond to the information collections in this part is mandated under the Act (43 U.S.C. 1331 *et seq.*) and the Act's Amendments of 1978 (43 U.S.C. 1801 *et seq.*). Some responses are also required to obtain or retain a benefit or may be voluntary. Proprietary information will be protected under § 250.197, Data and information to be made available to the public or for limited inspection; parts 30 CFR Parts 251, 252; and the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations at 43 CFR part 2.

(c) The Paperwork Reduction Act of 1995 requires us to inform the public that 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.

(d) Send comments regarding any aspect of the collections of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

(e) BSEE is collecting this information for the reasons given in the following table:

30 CFR Subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(1) Subpart A, General (1014–0022), including Forms BSEE–0011, iSEE; BSEE–0132, Evacuation Statistics; BSEE–0143, Facility/Equipment Damage Report; BSEE–1832, Notification of Incidents of Noncompliance.	(i) Determine that activities on the OCS comply with statutory and regulatory requirements; are safe and protect the environment; and result in diligent development and production on OCS leases. (ii) Support the unproved and proved reserve estimation, resource assessment, and fair market value determinations. (iii) Assess damage and project any disruption of oil and gas production from the OCS after a major natural occurrence.
(2) Subpart B, Plans and Information (1014–0024)	Evaluate Deepwater Operations Plans for compliance with statutory and regulatory requirements
(3) Subpart C, Pollution Prevention and Control (1014–0023)	(i) Evaluate measures to prevent unauthorized discharge of pollutants into the offshore waters. (ii) Ensure action is taken to control pollution.
(4) Subpart D, Oil and Gas and Drilling Operations (1014–0018), including Forms BSEE–0125, End of Operations Report; BSEE–0133, Well Activity Report; and BSEE–0133S, Open Hole Data Report.	(i) Evaluate the equipment and procedures to be used in drilling operations on the OCS. (ii) Ensure that drilling operations meet statutory and regulatory requirements.
(5) Subpart E, Oil and Gas Well-Completion Operations (1014–0004)	(i) Evaluate the equipment and procedures to be used in well-completion operations on the OCS. (ii) Ensure that well-completion operations meet statutory and regulatory requirements.
(6) Subpart F, Oil and Gas Well Workover Operations (1014–0001)	(i) Evaluate the equipment and procedures to be used during well-workover operations on the OCS. (ii) Ensure that well-workover operations meet statutory and regulatory requirements.
(7) Subpart G, Blowout Preventer Systems (1014–0028), including Form BSEE–0144, Rig Movement Notification Report.	(i) Evaluate the equipment and procedures to be used during well drilling, completion, workover, and abandonment operations on the OCS. (ii) Ensure that well operations meet statutory and regulatory requirements.
(8) Subpart H, Oil and Gas Production Safety Systems (1014–0003)	(i) Evaluate the equipment and procedures that will be used during production operations on the OCS. (ii) Ensure that production operations meet statutory and regulatory requirements.
(9) Subpart I, Platforms and Structures (1014–0011)	(i) Evaluate the design, fabrication, and installation of platforms on the OCS. (ii) Ensure the structural integrity of platforms installed on the OCS.
(10) Subpart J, Pipelines and Pipeline Rights-of-Way (1014–0016), including Form BSEE–0149, Assignment of Federal OCS Pipeline Right-of-Way Grant.	(i) Evaluate the design, installation, and operation of pipelines on the OCS. (ii) Ensure that pipeline operations meet statutory and regulatory requirements.
(11) Subpart K, Oil and Gas Production Rates (1014–0019), including Forms BSEE–0126, Well Potential Test Report and BSEE–0128, Semi-annual Well Test Report.	(i) Evaluate production rates for hydrocarbons produced on the OCS. (ii) Ensure economic maximization of ultimate hydrocarbon recovery.
(12) Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security (1014–0002).	(i) Evaluate the measurement of production, commingling of hydrocarbons, and site security plans. (ii) Ensure that produced hydrocarbons are measured and commingled to provide for accurate royalty payments and security.
(13) Subpart M, Unitization (1014–0015)	(i) Evaluate the unitization of leases. (ii) Ensure that unitization prevents waste, conserves natural resources, and protects correlative rights.
(14) Subpart N, Remedies and Penalties	(The requirements in subpart N are exempt from the Paperwork Reduction Act of 1995 according to 5 CFR 1320.4).
(15) Subpart O, Well Control and Production Safety Training (1014–0008)	(i) Evaluate training program curricula for OCS workers, course schedules, and attendance.

30 CFR Subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
	(ii) Ensure that training programs are technically accurate and sufficient to meet statutory and regulatory requirements, and that workers are properly trained.
(16) Subpart P, Sulfur Operations (1014–0006)	(i) Evaluate sulfur exploration and development operations on the OCS. (ii) Ensure that OCS sulfur operations meet statutory and regulatory requirements and will result in diligent development and production of sulfur leases.
(17) Subpart Q, Decommissioning Activities (1014–0010)	Ensure that decommissioning activities, site clearance, and platform or pipeline removal are properly performed to meet statutory and regulatory requirements and do not conflict with other users of the OCS.
(18) Subpart S, Safety and Environmental Management Systems (1014–0017), including Form BSEE–0131, Performance Measures Data.	(i) Evaluate operators' policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel). (ii) Evaluate Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.
(19) Application for Permit to Drill (APD, Revised APD), Form BSEE–0123; and Supplemental APD Information Sheet, Form BSEE–0123S, and all supporting documentation (1014–0025).	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling. (ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.
(20) Application for Permit to Modify (APM), Form BSEE–0124, and supporting documentation (1014–0026).	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling and to evaluate well plan modifications and changes in major equipment. (ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26015, Apr. 29, 2016; 81 FR 36149, June 6, 2016]

Subpart B—Plans and Information

GENERAL INFORMATION

§ 250.200 Definitions.

Acronyms and terms used in this subpart have the following meanings:

(a) *Acronyms* used frequently in this subpart are listed alphabetically below:

BOEM means Bureau of Ocean Energy Management of the Department of the Interior.

BSEE means Bureau of Safety and Environmental Enforcement of the Department of the Interior.

CID means Conservation Information Document.

CZMA means Coastal Zone Management Act.

DOCD means Development Operations Coordination Document.

DPP means Development and Production Plan.

DWOP means Deepwater Operations Plan.

EIA means Environmental Impact Analysis.

EP means Exploration Plan.

NPDES means National Pollutant Discharge Elimination System.

NTL means Notice to Lessees and Operators.

OCS means Outer Continental Shelf.

(b) Terms used in this subpart are listed alphabetically below:

Amendment means a change you make to an EP, DPP, or DOCD that is pending before BOEM for a decision (see 30 CFR 550.232(d) and 550.267(d)).

Modification means a change required by the Regional Supervisor to an EP, DPP, or DOCD (see 30 CFR 550.233(b)(2) and 550.270(b)(2)) that is pending before BOEM for a decision because the OCS plan is inconsistent with applicable requirements.

New or unusual technology means equipment or procedures that:

(1) Have not been used previously or extensively in a BSEE OCS Region;

(2) Have not been used previously under the anticipated operating conditions; or

(3) Have operating characteristics that are outside the performance parameters established by this part.

Non-conventional production or completion technology includes, but is not limited to, floating production systems, tension leg platforms, spars, floating production, storage, and offloading systems, guyed towers, compliant towers, subsea manifolds, and other subsea production components that rely on a remote site or host facility for utility and well control services.

Offshore vehicle means a vehicle that is capable of being driven on ice.

Resubmitted OCS plan means an EP, DPP, or DOCD that contains changes you make to an OCS plan that BOEM has disapproved (see 30 CFR 550.234(b), 550.272(a), and 550.273(b)).

Revised OCS plan means an EP, DPP, or DOCD that proposes changes to an approved OCS plan, such as those in the location of a well or platform, type of drilling unit, or location of the onshore support base (see 30 CFR 550.283(a)).

Supplemental OCS plan means an EP, DPP, or DOCD that proposes the addition to an approved OCS plan of an activity that requires approval of an application or permit (see 30 CFR 550.283(b)).

§ 250.201 What plans and information must I submit before I conduct any activities on my lease or unit?

(a) *Plans and documents.* Before you conduct the activities on your lease or unit listed in the following table, you must submit, and BSEE must approve, the listed plans and documents. Your plans and documents may cover one or more leases or units.

You must submit a(n) . . .	Before you . . .
(1) [Reserved]	
(2) [Reserved]	
(3) [Reserved]	
(4) Deepwater Operations Plan (DWOP),	Conduct post-drilling installation activities in any water depth associated with a development project that will involve the use of a non-conventional production or completion technology.
(5) [Reserved]	
(6) [Reserved]	

(b) *Submitting additional information.* On a case-by-case basis, the Regional Supervisor may require you to submit additional information if the Regional Supervisor determines that it is necessary to evaluate your proposed plan or document.

(c) *Limiting information.* The Regional Director may limit the amount of information or analyses that you otherwise must provide in your proposed plan or document under this subpart when:

(1) Sufficient applicable information or analysis is readily available to BSEE;

(2) Other coastal or marine resources are not present or affected;

(3) Other factors such as technological advances affect information needs; or

(4) Information is not necessary or required for a State to determine consistency with their CZMA Plan.

(d) *Referencing.* In preparing your proposed plan or document, you may reference information and data discussed in other plans or documents you previously submitted or that are otherwise readily available to BSEE.

§§ 250.202–250.203 [Reserved]

§ 250.204 How must I protect the rights of the Federal government?

(a) To protect the rights of the Federal government, you must either:

(1) Drill and produce the wells that the Regional Supervisor determines are necessary to protect the Federal government from loss due to production on other leases or units or from adjacent lands under the jurisdiction of other entities (e.g., State and foreign governments); or

(2) Pay a sum that the Regional Supervisor determines as adequate to compensate the Federal government for your failure to drill and produce any well.

(b) Payment under paragraph (a)(2) of this section may constitute production in paying quantities for the purpose of extending the lease term.

(c) You must complete and produce any penetrated hydrocarbon-bearing zone that the Regional Supervisor determines is necessary to conform to sound conservation practices.

§ 250.205 Are there special requirements if my well affects an adjacent property?

For wells that could intersect or drain an adjacent property, the Regional Supervisor may require special measures to protect the rights of the Federal government and objecting lessees or operators of adjacent leases or units.

POST-APPROVAL REQUIREMENTS FOR THE EP, DPP, AND DOCD

§ 250.282 Do I have to conduct post-approval monitoring?

The Regional Supervisor may direct you to conduct monitoring programs. You must retain copies of all monitoring data obtained or derived from your monitoring programs and make them available to BSEE upon request. The Regional Supervisor may require you to:

(a) *Monitoring plans.* Submit monitoring plans for approval before you begin work; and

(b) *Monitoring reports.* Prepare and submit reports that summarize and analyze data and information obtained or derived from your monitoring programs. The Regional Supervisor will specify requirements for preparing and submitting these reports.

DEEPWATER OPERATIONS PLAN (DWOP)

§ 250.286 What is a DWOP?

(a) A DWOP is a plan that provides sufficient information for BSEE to review a deepwater development project, and any other project that uses non-conventional production or completion technology, from a total system approach. The DWOP does not replace, but supplements other submittals required by the regulations such as BOEM Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents. BSEE will use the information in your DWOP to determine whether the project will be developed in an acceptable manner, particularly with respect to operational safety and environmental protection issues involved with non-conventional production or completion technology.

(b) The DWOP process consists of two parts: a Conceptual Plan and the DWOP. Section 250.289 prescribes what the Conceptual Plan must contain, and § 250.292 prescribes what the DWOP must contain.

§ 250.287 For what development projects must I submit a DWOP?

You must submit a DWOP for each development project in which you will use non-conventional production or completion technology, regardless of water depth. If you are unsure whether BSEE considers the technology of your project non-conventional, you must contact the Regional Supervisor for guidance.

§ 250.288 When and how must I submit the Conceptual Plan?

You must submit four copies, or one hard copy and one electronic version, of the Conceptual Plan to the Regional Director after you have decided on the general concept(s) for development and before you begin engineering design of the well safety control system or subsea production systems to be used after well completion.

§ 250.289 What must the Conceptual Plan contain?

In the Conceptual Plan, you must explain the general design basis and philosophy that you will use to develop the field. You must include the following information:

(a) An overview of the development concept(s);

(b) A well location plat;

(c) The system control type (*i.e.*, direct hydraulic or electro-hydraulic); and

(d) The distance from each of the wells to the host platform.

§ 250.290 What operations require approval of the Conceptual Plan?

You may not complete any production well or install the subsea wellhead and well safety control system (often called the tree) before BSEE has approved the Conceptual Plan.

§ 250.291 When and how must I submit the DWOP?

You must submit four copies, or one hard copy and one electronic version,

of the DWOP to the Regional Director after you have substantially completed safety system design and before you begin to procure or fabricate the safety and operational systems (other than the tree), production platforms, pipelines, or other parts of the production system.

§ 250.292 What must the DWOP contain?

You must include the following information in your DWOP:

(a) A description and schematic of the typical wellbore, casing, and completion;

(b) Structural design, fabrication, and installation information for each surface system, including host facilities;

(c) Design, fabrication, and installation information on the mooring systems for each surface system;

(d) Information on any active stationkeeping system(s) involving thrusters or other means of propulsion used with a surface system;

(e) Information concerning the drilling and completion systems;

(f) Design and fabrication information for each riser system (e.g., drilling, workover, production, and injection);

(g) Pipeline information;

(h) Information about the design, fabrication, and operation of an offtake system for transferring produced hydrocarbons to a transport vessel;

(i) Information about subsea wells and associated systems that constitute all or part of a single project development covered by the DWOP;

(j) Flow schematics and Safety Analysis Function Evaluation (SAFE) charts (API RP 14C, subsection 4.3c, incorporated by reference in § 250.198) of the production system from the Surface Controlled Subsurface Safety Valve (SCSSV) downstream to the first item of separation equipment;

(k) A description of the surface/subsea safety system and emergency support systems to include a table that depicts what valves will close, at what times, and for what events or reasons;

(l) A general description of the operating procedures, including a table summarizing the curtailment of production and offloading based on operational considerations;

(m) A description of the facility installation and commissioning procedure;

(n) A discussion of any new technology that affects hydrocarbon recovery systems;

(o) A list of any alternate compliance procedures or departures for which you anticipate requesting approval;

(p) If you propose to use a pipeline free standing hybrid riser (FSHR) on a permanent installation that utilizes a buoyancy air can suspended from the top of the riser, you must provide the following information in your DWOP in the discussions required by paragraphs (f) and (g) of this section:

(1) A detailed description and drawings of the FSHR, buoy, and the associated connection system;

(2) Detailed information regarding the system used to connect the FSHR to the buoyancy air can, and associated redundancies; and

(3) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and the associated connection system for fatigue, stress, and any other abnormal condition (e.g., corrosion) that may negatively impact the riser system's integrity.

(q) Payment of the service fee listed in § 250.125.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

§ 250.293 What operations require approval of the DWOP?

You may not begin production until BSEE approves your DWOP.

§ 250.294 May I combine the Conceptual Plan and the DWOP?

If your development project meets the following criteria, you may submit a combined Conceptual Plan/DWOP on or before the deadline for submitting the Conceptual Plan.

(a) The project is located in water depths of less than 400 meters (1,312 feet); and

(b) The project is similar to projects involving non-conventional production or completion technology for which you have obtained approval previously.

§ 250.295 When must I revise my DWOP?

You must revise either the Conceptual Plan or your DWOP to reflect changes in your development project that materially alter the facilities, equipment, and systems described in your plan. You must submit the revision within 60 days after any material change to the information required for that part of your plan.

Subpart C—Pollution Prevention and Control

§ 250.300 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 Manager 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 Manager.

(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 Manager may restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. The District Manager may also restrict the use of components that 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 Manager. For Arctic OCS exploratory drilling, you must capture all petroleum-based mud to prevent its discharge into the marine environment. The Regional Supervisor may also require you to capture, during your Arctic OCS exploratory drilling operations, all water-based mud from operations after completion of the hole for the conductor casing to prevent its discharge into the marine environment, based on various factors including, but not limited to:

(i) The proximity of your exploratory drilling operation to subsistence hunting and fishing locations;

(ii) The extent to which discharged mud may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or

(iii) The extent to which discharged mud may adversely affect marine mammals, fish, or their habitat.

(2) You must obtain approval from the District Manager of the method you plan to use to dispose of drill cuttings, sand, and other well solids. For Arctic OCS exploratory drilling, you must capture all cuttings from operations that utilize petroleum-based mud to prevent their discharge into the marine environment. The Regional Supervisor may also require you to capture, during your Arctic OCS exploratory drilling operations, all cuttings from operations that utilize water-based mud after completion of the hole for the conductor casing to prevent their discharge into the marine environment, based on various factors including, but not limited to:

(i) The proximity of your exploratory drilling operation to subsistence hunting and fishing locations;

(ii) The extent to which discharged cuttings may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or

(iii) The extent to which discharged cuttings may adversely affect marine mammals, fish, or their habitat.

(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 Manager.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 46560, July 15, 2016]

§ 250.301 Inspection of facilities.

Drilling and production facilities shall be inspected daily or at intervals approved or prescribed by the District Manager 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.

Subpart D—Oil and Gas Drilling Operations

GENERAL REQUIREMENTS

§ 250.400 General requirements.

Drilling operations must be conducted in a safe 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. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26017, Apr. 29, 2016]

§§ 250.401–250.403 [Reserved]

§ 250.404 What are the requirements for the crown block?

You must have a crown block safety device that prevents the traveling block from striking the crown block. You must check the device for proper operation at least once per week and after each drill-line slipping operation and record the results of this operational check in the driller's report.

§ 250.405 What are the safety requirements for diesel engines used on a drilling rig?

You must equip each diesel engine with an air intake device to shut down the diesel engine in the event of a runaway.

(a) For a diesel engine that is not continuously manned, you must equip the engine with an automatic shutdown device;

(b) For a diesel engine that is continuously manned, you may equip the engine with either an automatic or remote manual air intake shutdown device;

(c) You do not have to equip a diesel engine with an air intake device if it meets one of the following criteria:

(1) Starts a larger engine;

(2) Powers a firewater pump;

(3) Powers an emergency generator;

(4) Powers a BOP accumulator system;

(5) Provides air supply to divers or confined entry personnel;

(6) Powers temporary equipment on a nonproducing platform;

(7) Powers an escape capsule; or

(8) Powers a portable single-cylinder rig washer.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36149, June 6, 2016]

§ 250.406 [Reserved]

§ 250.407 What tests must I conduct to determine reservoir characteristics?

You must determine the presence, quantity, quality, and reservoir characteristics of oil, gas, sulphur, and water in the formations penetrated by logging, formation sampling, or well testing.

§ 250.408 May I use alternative procedures or equipment during drilling operations?

You may use alternative procedures or equipment during drilling operations after receiving approval from the District Manager. You must identify and discuss your proposed alternative procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE–0123) (see § 250.414(h)). Procedures for obtaining approval are described in § 250.141 of this part.

§ 250.409 May I obtain departures from these drilling requirements?

The District Manager may approve departures from the drilling requirements specified in this subpart. You may apply for a departure from drilling requirements by writing to the District Manager. You should identify and discuss the departure you are requesting in your APD (see § 250.414(h)).

APPLYING FOR A PERMIT TO DRILL

§ 250.410 How do I obtain approval to drill a well?

You must obtain written approval from the District Manager before you begin drilling any well or before you sidetrack, bypass, or deepen a well. To obtain approval, you must:

(a) Submit the information required by §§ 250.411 through 250.418;

(b) Include the well in your approved Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD);

(c) Meet the oil spill financial responsibility requirements for offshore facilities as required by 30 CFR part 553; and

(d) Submit the following to the District Manager:

(1) An original and two complete copies of Form BSEE–0123, Application for Permit to Drill (APD), and Form BSEE–0123S, Supplemental APD Information Sheet;

(2) A separate public information copy of forms BSEE–0123 and BSEE–0123S that meets the requirements of § 250.186; and

(3) Payment of the service fee listed in § 250.125.

§ 250.411 What information must I submit with my application?

In addition to forms BSEE–0123 and BSEE–0123S, you must include the information required in this subpart and subpart G of this part, including the following:

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well,	§ 250.412.
(b) Design criteria used for the proposed well,	§ 250.413.
(c) Drilling prognosis,	§ 250.414.
(d) Casing and cementing programs,	§ 250.415.
(e) Diverter systems descriptions,	§ 250.416.
(f) BOP system descriptions,	§ 250.731.
(g) Requirements for using a MODU, and	§ 250.713.
(h) Additional information.	§ 250.418.

[81 FR 26017, Apr. 29, 2016]

§ 250.412 What requirements must the location plat meet?

The location plat must:

(a) Have a scale of 1:24,000 (1 inch = 2,000 feet);

(b) Show the surface and subsurface locations of the proposed well and all the wells in the vicinity;

(c) Show the surface and subsurface locations of the proposed well in feet or meters from the block line;

(d) Contain the longitude and latitude coordinates, and either Universal Transverse Mercator grid-system coordinates or state plane coordinates in the Lambert or Transverse Mercator Projection system for the surface and subsurface locations of the proposed well; and

(e) State the units and geodetic datum (including whether the datum is North American Datum 27 or 83) for these coordinates. If the datum was converted, you must state the method used for this conversion, since the various methods may produce different values.

§ 250.413 What must my description of well drilling design criteria address?

Your description of well drilling design criteria must address:

(a) Pore pressures;

(b) Formation fracture gradients, adjusted for water depth;

(c) Potential lost circulation zones;

(d) Drilling fluid weights;

(e) Casing setting depths;

(f) Maximum anticipated surface pressures. For this section, maximum anticipated surface pressures are the pressures that you reasonably expect to be exerted upon a casing string and its related wellhead equipment. In calculating maximum anticipated surface pressures, you must consider: drilling, completion, and producing conditions; drilling fluid densities to be used below various casing strings; fracture gradients of the exposed formations; casing setting depths; total well depth; formation fluid types; safety margins; and other pertinent conditions. You must include the calculations used to determine the pressures for the drilling and the completion phases, including the anticipated surface pressure used for designing the production string;

(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights (surface and downhole), planned safe drilling margin, and casing setting depths in true vertical measurements;

(h) A summary report of the shallow hazards site survey that describes the geological and manmade conditions if not previously submitted; and

(i) Permafrost zones, if applicable.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

§ 250.414 What must my drilling prognosis include?

Your drilling prognosis must include a brief description of the procedures you will follow in drilling the well. This prognosis includes but is not limited to the following:

(a) Projected plans for coring at specified depths;

(b) Projected plans for logging;

(c) Planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations.

(1) Your safe drilling margin must also include use of equivalent downhole mud weight that is:

(i) Greater than the estimated pore pressure; and

(ii) Except as provided in paragraph (c)(2) of this section, a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient.

(2) In lieu of meeting the criteria in paragraph (c)(1)(ii) of this section, you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight. You may submit such justification in advance of your full APD, and BSEE may consider such justification for approval when submitted. Any such approval will be contingent upon your confirmation in the APD that your plans and the information underlying your approved justification have not changed.

(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set and analogous well behavior observations, if available.

(d) Estimated depths to the top of significant marker formations;

(e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids;

(f) Estimated depths to major faults;

(g) Estimated depths of permafrost, if applicable;

(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;

(i) Projected plans for well testing (refer to § 250.460);

(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

(k) Any additional information required by the District Manager needed to clarify or evaluate your drilling prognosis.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

§ 250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

(a) The following well design information:

(1) Hole sizes;

(2) Bit depths (including measured and true vertical depth (TVD));

(3) Casing information, including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and

(4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

(b) Casing design safety factors for tension, collapse, and burst with the assumptions made to arrive at these values;

(c) Type and amount of cement (in cubic feet) planned for each casing string;

(d) In areas containing permafrost, setting depths for conductor and surface casing based on the anticipated depth of the permafrost. Your program must provide protection from thaw subsidence and freezeback effect, proper anchorage, and well control;

(e) A statement of how you evaluated the best practices included in API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deep Water Wells (as incorporated by reference in § 250.198), if you drill a well in water depths greater than 500 feet and are in either of the following two areas:

(1) An ''area with an unknown shallow water flow potential'' is a zone or geologic formation where neither the

presence nor absence of potential for a shallow water flow has been confirmed.

(2) An ''area known to contain a shallow water flow hazard'' is a zone or geologic formation for which drilling has confirmed the presence of shallow water flow; and

(f) A written description of how you evaluated the best practices included in API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition (as incorporated by reference in § 250.198). Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API Standard 65—Part 2, Sections 4 and 5).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50891, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016]

§ 250.416 What must I include in the diverter description?

You must include in the diverter description:

(a) A description of the diverter system and its operating procedures;

(b) A schematic drawing of the diverter system (plan and elevation views) that shows:

(1) The size of the element installed in the diverter housing;

(2) Spool outlet internal diameter(s);

(3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and

(4) Valve type, size, working pressure rating, and location.

[81 FR 26018, Apr. 29, 2016]

§ 250.417 [Reserved]

§ 250.418 What additional information must I submit with my APD?

You must include the following with the APD:

(a) Rated capacities of the drilling rig and major drilling equipment, if not already on file with the appropriate District office;

(b) A drilling fluids program that includes the minimum quantities of drilling fluids and drilling fluid materials, including weight materials, to be kept at the site;

(c) A proposed directional plot if the well is to be directionally drilled;

(d) A Hydrogen Sulfide Contingency Plan (see § 250.490), if applicable, and not previously submitted;

(e) A welding plan (see §§ 250.109 to 250.113) if not previously submitted;

(f) In areas subject to subfreezing conditions, evidence that the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions;

(g) A request for approval, if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

(h) Certification of your casing and cementing program as required in § 250.420(a)(7); and

(i) Such other information as the District Manager may require.

(j) For Arctic OCS exploratory drilling operations, you must provide the information required by § 250.470.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016; 81 FR 46561, July 15, 2016]

CASING AND CEMENTING REQUIREMENTS

§ 250.420 What well casing and cementing requirements must I meet?

You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of subpart G of this part.

(a) *Casing and cementing program requirements.* Your casing and cementing programs must:

(1) Properly control formation pressures and fluids;

(2) Prevent the direct or indirect release of fluids from any stratum through the wellbore into offshore waters;

(3) Prevent communication between separate hydrocarbon-bearing strata;

(4) Protect freshwater aquifers from contamination;

(5) Support unconsolidated sediments;

(6) Provide adequate centralization consistent with the guidelines of API

Standard 65—Part 2 (as incorporated by reference in § 250.198); and

(7)(i) Include a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions, and is sufficient to satisfy the tests and requirements of this section and § 250.423. Submit this certification with your APD (Form BSEE–0123).

(ii) You must have the registered professional engineer involved in the casing and cementing design process.

(iii) The registered professional engineer must be registered in a state of the United States and have sufficient expertise and experience to perform the certification.

(b) *Casing requirements.* (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof.

(2) The casing design must include safety measures that ensure well control during drilling and safe operations during the life of the well.

(3) On all wells that use subsea BOP stacks, you must include two independent barriers, including one mechanical barrier, in each annular flow path (examples of barriers include, but are not limited to, primary cement job and seal assembly). For the final casing string (or liner if it is your final string), you must install one mechanical barrier in addition to cement to prevent flow in the event of a failure in the cement. A dual float valve, by itself, is not considered a mechanical barrier. These barriers cannot be modified prior to or during completion or abandonment operations. The BSEE District Manager may approve alternative options under § 250.141. You must submit documentation of this installation to BSEE in the End-of-Operations Report (Form BSEE–0125).

(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

(c) *Cementing requirements.* (1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations. (If a liner is used refer to § 250.421(f)).

(2) You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

§ 250.421 What are the casing and cementing requirements by type of casing string?

The table in this section identifies specific design, setting, and cementing requirements for casing strings and liners. For the purposes of subpart D, the casing strings in order of normal installation are as follows: drive or structural, conductor, surface, intermediate, and production casings (including liners). The District Manager may approve or prescribe other casing and cementing requirements where appropriate.

Casing type	Casing requirements	Cementing requirements
(a) Drive or Structural	Set by driving, jetting, or drilling to the minimum depth as approved or prescribed by the District Manager.	If you drilled a portion of this hole, you must use enough cement to fill the annular space back to the mudline.

Casing type	Casing requirements	Cementing requirements
(b) Conductor	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone.	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.
(c) Surface	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths.	Use enough cement to fill the calculated annular space to at least 200 feet measured depth (MD) inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.
(d) Intermediate	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions.	Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well. As a minimum, you must cement the annular space 500 feet MD above the casing shoe and 500 feet MD above each zone to be isolated.
(e) Production	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions.	Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe. As a minimum, you must cement the annular space at least 500 feet MD above the casing shoe and 500 feet MD above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as surface casing, you must set the top of the liner at least 200 feet MD above the previous casing/liner shoe.. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet MD above the previous casing shoe. You may not use a liner as conductor casing. A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26018, Apr. 29, 2016; 84 FR 21974, May 15, 2019]

§ 250.422 When may I resume drilling after cementing?

(a) After cementing surface, intermediate, or production casing (or liners), you may resume drilling after the cement has been held under pressure for 12 hours. For conductor casing, you may resume drilling after the cement has been held under pressure for 8 hours. One acceptable method of holding cement under pressure is to use float valves to hold the cement in place.

(b) If you plan to nipple down your diverter or BOP stack during the 8- or 12-hour waiting time, you must determine, before nippling down, when it will be safe to do so. You must base your determination on a knowledge of formation conditions, cement composition, effects of nippling down, presence of potential drilling hazards, well conditions during drilling, cementing, and post cementing, as well as past experience.

§ 250.423 What are the requirements for casing and liner installation?

You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the casing string.

(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the liner.

(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners.

(1) You must submit for approval with your APD, test procedures and criteria for a successful test.

(2) You must document all your test results and make them available to BSEE upon request.

[81 FR 26019, Apr. 29, 2016, as amended at 84 FR 21974, May 15, 2019]

§§ 250.424–250.426 [Reserved]

§ 250.427 What are the requirements for pressure integrity tests?

You must conduct a pressure integrity test below the surface casing or liner and all intermediate casings or liners. The District Manager may require you to run a pressure-integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. You must conduct each pressure integrity test after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe. You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight if identified in an approved APD.

(a) You must use the pressure integrity test and related hole-behavior observations, such as pore-pressure test results, gas-cut drilling fluid, and well kicks to adjust the drilling fluid program and the setting depth of the next casing string. You must record all test results and hole-behavior observations made during the course of drilling related to formation integrity and pore pressure in the driller's report.

(b) While drilling, you must maintain the safe drilling margin identified in § 250.414. When you cannot maintain the safe drilling margin, you must:

(1) Suspend drilling operations and submit proposed remedial actions to the District Manager. The District Manager must review and approve your proposed remedial actions, which may include limited drilling through a lost circulation zone; or

(2) Notify the District Manager and take further action in accordance with API Bulletin 92L (as incorporated by reference in § 250.198), if appropriate. You must submit a revised permit documenting any responsive actions taken.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26019, Apr. 29, 2016; 84 FR 21974, May 15, 2019]

§ 250.428 What must I do in certain cementing and casing situations?

The table in this section describes actions that lessees must take when certain situations occur during casing and cementing activities.

If you encounter the following situation:	Then you must . . .
(a) Have unexpected formation pressures or conditions that warrant revising your casing design,	Submit a revised casing program to the District Manager for approval.
(b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations,	Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.
(c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment),	(1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; (iii) Using tracers in the cement and logging them prior to drill out; or (iv) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.

If you encounter the following situation:	Then you must . . .
(d) Inadequate cement job,	Comply with § 250.428(c)(1) and take remedial actions. The District Manager must review and approve all remedial actions either through a previously approved contingency plan within the permit or remedial actions included in a revised permit before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program, that are not included in the approved permit, will require submittal of a certification by a professional engineer (PE) certifying that they have reviewed and approved the proposed changes. You must also meet any other requirements of the District Manager for remedial actions.
(e) Primary cement job that did not isolate abnormal pressure intervals,	Isolate those intervals from normal pressures by squeeze cementing before you complete; suspend operations; or abandon the well, whichever occurs first.
(f) Decide to produce a well that was not originally contemplated for production,	Have at least two cemented casing strings (does not include liners) in the well. Note: All producing wells must have at least two cemented casing strings.
(g) Want to drill a well without setting conductor casing,	Submit geologic data and information to the District Manager that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging and drilling fluid-monitoring from wells previously drilled within 500 feet of the proposed well path down to the next casing point.
(h) Need to use less than required cement for the surface casing during floating drilling operations to provide protection from burst and collapse pressures,	Submit information to the District Manager that demonstrates the use of less cement is necessary.
(i) Cement across a permafrost zone,	Use cement that sets before it freezes and has a low heat of hydration.
(j) Leave the annulus opposite a permafrost zone uncemented,	Fill the annulus with a liquid that has a freezing point below the minimum permafrost temperature and minimizes opposite a corrosion.
(k) Plan to use a valve(s) on the drive pipe during cementing operations for the conductor casing, surface casing, or liner,	Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26019, Apr. 29, 2016; 84 FR 21974, May 15, 2019]

DIVERTER SYSTEM REQUIREMENTS

§ 250.430 When must I install a diverter system?

You must install a diverter system before you drill a conductor or surface hole. The diverter system consists of a diverter sealing element, diverter lines, and control systems. You must design, install, use, maintain, and test the diverter system to ensure proper diversion of gases, water, drilling fluid, and other materials away from facilities and personnel.

§ 250.431 What are the diverter design and installation requirements?

You must design and install your diverter system to:

(a) Use diverter spool outlets and diverter lines that have a nominal diameter of at least 10 inches for surface wellhead configurations and at least 12 inches for floating drilling operations;

(b) Use dual diverter lines arranged to provide for downwind diversion capability;

(c) Use at least two diverter control stations. One station must be on the drilling floor. The other station must be in a readily accessible location away from the drilling floor;

(d) Use only remote-controlled valves in the diverter lines. All valves in the diverter system must be full-opening. You may not install manual or butterfly valves in any part of the diverter system;

(e) Minimize the number of turns (only one 90-degree turn allowed for each line for bottom-founded drilling units) in the diverter lines, maximize the radius of curvature of turns, and target all right angles and sharp turns;

(f) Anchor and support the entire diverter system to prevent whipping and vibration; and

(g) Protect all diverter-control instruments and lines from possible damage by thrown or falling objects.

§ 250.432 How do I obtain a departure to diverter design and installation requirements?

The table below describes possible departures from the diverter requirements and the conditions required for each departure. To obtain one of these departures, you must have discussed the departure in your APD and received approval from the District Manager.

If you want a departure to:	Then you must . . .
(a) Use flexible hose for diverter lines instead of rigid pipe,	Use flexible hose that has integral end couplings.
(b) Use only one spool outlet for your diverter system,	(1) Have branch lines that meet the minimum internal diameter requirements; and (2) Provide downwind diversion capability.
(c) Use a spool with an outlet with an internal diameter of less than 10 inches on a surface wellhead,	Use a spool that has dual outlets with an internal diameter of at least 8 inches.
(d) Use a single diverter line for floating drilling operations on a dynamically positioned drillship,	Maintain an appropriate vessel heading to provide for downwind diversion.

§ 250.433 What are the diverter actuation and testing requirements?

When you install the diverter system, you must actuate the diverter sealing element, diverter valves, and diverter-control systems and control stations. You must also flow-test the vent lines.

(a) For drilling operations with a surface wellhead configuration, you must actuate the diverter system at least once every 24-hour period after the initial test. After you have nippled up on conductor casing, you must pressure-test the diverter-sealing element and diverter valves to a minimum of 200 psi. While the diverter is installed, you must conduct subsequent pressure tests within 7 days after the previous test.

(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system within 7 days after the previous actuation. For subsequent testing, you may partially actuate the diverter element and a flow test is not required.

(c) You must alternate actuations and tests between control stations.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21975, May 15, 2019]

§ 250.434 What are the recordkeeping requirements for diverter actuations and tests?

You must record the time, date, and results of all diverter actuations and tests in the driller's report. In addition, you must:

(a) Record the diverter pressure test on a pressure chart;

(b) Require your onsite representative to sign and date the pressure test chart;

(c) Identify the control station used during the test or actuation;

(d) Identify problems or irregularities observed during the testing or actuations and record actions taken to remedy the problems or irregularities; and

(e) Retain all pressure charts and reports pertaining to the diverter tests and actuations at the facility for the duration of drilling the well.

§§ 250.440–250.451 [Reserved]

§ 250.452 What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations?

(a) When conducting exploratory drilling operations on the Arctic OCS, you must gather and monitor real-time data using an independent, automatic,

and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's fluid handling systems on the rig; and

(3) The well's downhole conditions as monitored by a downhole sensing system, when such a system is installed.

(b) During well operations, you must transmit the data identified in paragraph (a) of this section as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After well operations, you must store the data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must provide BSEE with access to your real-time monitoring data onshore upon request.

[81 FR 46561, July 15, 2016]

DRILLING FLUID REQUIREMENTS

§ 250.455 What are the general requirements for a drilling fluid program?

You must design and implement your drilling fluid program to prevent the loss of well control. This program must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas.

§ 250.456 What safe practices must the drilling fluid program follow?

Your drilling fluid program must include the following safe practices:

(a) Before starting out of the hole with drill pipe, you must properly condition the drilling fluid. You must circulate a volume of drilling fluid equal to the annular volume with the drill pipe just off-bottom. You may omit this practice if documentation in the driller's report shows:

(1) No indication of formation fluid influx before starting to pull the drill pipe from the hole;

(2) The weight of returning drilling fluid is within 0.2 pounds per gallon (1.5 pounds per cubic foot) of the drilling fluid entering the hole; and

(3) Other drilling fluid properties are within the limits established by the program approved in the APD.

(b) Record each time you circulate drilling fluid in the hole in the driller's report;

(c) When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume needed to fill the hole. Both sets of numbers must be posted near the driller's station. You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;

(d) You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;

(e) When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom;

(f) You must calculate and post near the driller's console the maximum pressures that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the District Manager). As a minimum, you must post the following two pressures:

(1) The surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and

(2) The lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the District Manager);

(g) You must install an operable drilling fluid-gas separator and

degasser before you begin drilling operations. You must maintain this equipment throughout the drilling of the well;

(h) Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids in the hole. If circulating out test fluids is not feasible, you may bullhead test fluids out of the drill-stem test string and tools with an appropriate kill weight fluid;

(i) When circulating, you must test the drilling fluid at least once each tour, or more frequently if conditions warrant. Your tests must conform to industry-accepted practices and include density, viscosity, and gel strength; hydrogenion concentration; filtration; and any other tests the District Manager requires for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and for kick detection. You must record the results of these tests in the drilling fluid report; and

(j) In areas where permafrost and/or hydrate zones are present or may be present, you must control drilling fluid temperatures to drill safely through those zones.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26020, Apr. 29, 2016]

§ 250.457 What equipment is required to monitor drilling fluids?

Once you establish drilling fluid returns, you must install and maintain the following drilling fluid-system monitoring equipment throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

(a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;

(b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;

(c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and

(d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm.

§ 250.458 What quantities of drilling fluids are required?

(a) You must use, maintain, and replenish quantities of drilling fluid and drilling fluid materials at the drill site as necessary to ensure well control. You must determine those quantities based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.

(b) You must record the daily inventories of drilling fluid and drilling fluid materials, including weight materials and additives in the drilling fluid report.

(c) If you do not have sufficient quantities of drilling fluid and drilling fluid material to maintain well control, you must suspend drilling operations.

§ 250.459 What are the safety requirements for drilling fluid-handling areas?

You must classify drilling fluid-handling areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class I, Division 1 and Division 2 (as incorporated by reference in § 250.198); or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class 1, Zone 0, Zone 1, and Zone 2 (as incorporated by reference in § 250.198). In areas where dangerous concentrations of combustible gas may accumulate, you must install and maintain a ventilation system and gas monitors. Drilling fluid-handling areas must have the following safety equipment:

(a) A ventilation system 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. In addition:

(1) If natural means provide adequate ventilation, then a mechanical ventilation system is not necessary;

(2) If a mechanical system does not run continuously, then it must activate when gas detectors indicate the presence of 1 percent or more of combustible gas by volume; and

(3) If discharges from a mechanical ventilation system may be hazardous, then you must maintain the drilling fluid-handling area at a negative pressure. You must protect the negative pressure area by using at least one of the following: a pressure-sensitive alarm, open-door alarms on each access to the area, automatic door-closing devices, air locks, or other devices approved by the District Manager;

(b) Gas detectors and alarms except in open areas where adequate ventilation is provided by natural means. You must test and recalibrate gas detectors quarterly. No more than 90 days may elapse between tests;

(c) Explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases. Where you use air for pressuring equipment, you must locate the air intake outside of and as far as practicable from hazardous areas; and

(d) Alarms that activate when the mechanical ventilation system fails.

OTHER DRILLING REQUIREMENTS

§ 250.460 What are the requirements for conducting a well test?

(a) If you intend to conduct a well test, you must include your projected plans for the test with your APD (form BSEE–0123) or in an Application for Permit to Modify (APM) (form BSEE–0124). Your plans must include at least the following information:

(1) Estimated flowing and shut-in tubing pressures;

(2) Estimated flow rates and cumulative volumes;

(3) Time duration of flow, buildup, and drawdown periods;

(4) Description and rating of surface and subsurface test equipment;

(5) Schematic drawing, showing the layout of test equipment;

(6) Description of safety equipment, including gas detectors and fire-fighting equipment;

(7) Proposed methods to handle or transport produced fluids; and

(8) Description of the test procedures.

(b) You must give the District Manager at least 24-hours notice before starting a well test.

§ 250.461 What are the requirements for directional and inclination surveys?

For this subpart, BSEE classifies a well as vertical if the calculated average of inclination readings does not exceed 3 degrees from the vertical.

(a) *Survey requirements for a vertical well.* (1) You must conduct inclination surveys on each vertical well and record the results. Survey intervals may not exceed 1,000 feet during the normal course of drilling;

(2) You must also conduct a directional survey that provides both inclination and azimuth, and digitally record the results in electronic format:

(i) Within 500 feet of setting surface or intermediate casing;

(ii) Within 500 feet of setting any liner; and

(iii) When you reach total depth.

(b) *Survey requirements for a directional well.* You must conduct directional surveys on each directional well and digitally record the results. Surveys must give both inclination and azimuth at intervals not to exceed 500 feet during the normal course of drilling. Intervals during angle-changing portions of the hole may not exceed 180 feet.

(c) *Measurement while drilling.* You may use measurement-while-drilling technology if it meets the requirements of this section.

(d) *Composite survey requirements.* (1) Your composite directional survey must show the interval from the bottom of the conductor casing to total depth. In the absence of conductor casing, the survey must show the interval from the bottom of the drive or structural casing to total depth; and

(2) You must correct all surveys to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north after making the magnetic-to-true-north correction. Surveys must show the

magnetic and grid corrections used and include a listing of the directionally computed inclinations and azimuths.

(e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder. This could occur when the adjoining leaseholder requests a copy of the survey for the protection of correlative rights.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21975, May 15, 2019]

§ 250.462 What are the source control, containment, and collocated equipment requirements?

For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.

(a) To determine your required source control and containment capabilities you must do the following:

(1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well.

(2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment to regain control of the well. SCCE means the capping stack, cap-and-flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels, which have the collective purpose to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment based on the determinations outlined in paragraph (a) of this section. This SCCE, supporting equipment, and collocated equipment may include, but is not limited to, the following:

(1) Subsea containment and capture equipment, including containment domes and capping stacks;

(2) Subsea utility equipment including hydraulic power sources and hydrate control equipment;

(3) Collocated equipment including dispersant injection equipment;

(4) Riser systems;

(5) Remotely operated vehicles (ROVs);

(6) Capture vessels;

(7) Support vessels; and

(8) Storage facilities.

(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE–0123. The description of your containment capabilities must contain the following:

(1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor;

(2) A discussion of the determination required in paragraph (a) of this section; and

(3) Information showing that you have access to and the ability to deploy all equipment required by paragraph (b) of this section.

(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your:

(1) Well design changes; or

(2) Approved source control and containment equipment is out of service.

(e) You must maintain, test, and inspect the source control, containment, and collocated equipment identified in the following table according to these requirements:

Equipment	Requirements, you must:	Additional information
(1) Capping stacks, ...	(i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests),	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in after being functioned.

Equipment	Requirements, you must:	Additional information
	(ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE (if available) and an independent third party..	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	
(2) Production safety systems used for flow and capture operations,	(i) Meet or exceed the requirements set forth in Subpart H, excluding required equipment that would be installed below the wellhead or that is not applicable to the cap and flow system.	
	(ii) Have all equipment unique to containment operations available for inspection at all times.	
(3) Subsea utility equipment,.	Have all equipment utilized solely for containment operations available for inspection at all times.	Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, and hydrate control equipment.
(4) Collocated equipment designated by the operator in the Regional Containment Demonstration (RCD) or Well Containment Plan (WCP),.	Have equipment available for inspection at all times.	Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment.

[81 FR 26020, Apr. 29, 2016, as amended at 84 FR 21975, May 15, 2019]

§ 250.463 Who establishes field drilling rules?

(a) The District Manager may establish field drilling rules different from the requirements of this subpart when geological and engineering information shows that specific operating requirements are appropriate. You must comply with field drilling rules and nonconflicting requirements of this subpart. The District Manager may amend or cancel field drilling rules at any time.

(b) You may request the District Manager to establish, amend, or cancel field drilling rules.

APPLYING FOR A PERMIT TO MODIFY AND WELL RECORDS

§ 250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to BSEE?

(a) You must submit an APM (form BSEE–0124) or an End of Operations Report (form BSEE–0125) and other materials to the Regional Supervisor as shown in the following table. You must also submit a public information copy of each form.

When you . . .	Then you must . . .	And . . .
(1) Intend to revise your drilling plan, change major drilling equipment, or plugback,	Submit form BSEE–0124 or request oral approval,	Receive written or oral approval from the District Manager before you begin the intended operation. If you get an approval, you must submit form BSEE–0124 no later than the end of the 3rd business day following the oral approval. In all cases, or you must meet the additional requirements in paragraph (b) of this section.
(2) Determine a well's final surface location, water depth, and the rotary kelly bushing elevation,	Immediately Submit a form BSEE–0124,	Submit a plat certified by a registered land surveyor that meets the requirements of § 250.412.
(3) Move a drilling unit from a wellbore before completing a well,	Submit forms BSEE–0124 and BSEE–0125 within 30 days after the suspension of wellbore operations,	Submit appropriate copies of the well records.

(b) If you intend to perform any of the actions specified in paragraph (a)(1) of this section, you must meet the following additional requirements:

(1) Your APM (Form BSEE–0124) must contain a detailed statement of the proposed work that would materially change from the approved APD. The submission of your APM must be accompanied by payment of the service fee listed in § 250.125;

(2) Your form BSEE–0124 must include the present status of the well, depth of all casing strings set to date, well depth, present production zones and productive capability, and all other information specified; and

(3) Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE–0125, as required under § 250.744.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26021, Apr. 29, 2016]

§§ 250.466–250.469 [Reserved]

ADDITIONAL ARCTIC OCS REQUIREMENTS

SOURCE: 81 FR 46561, July 15, 2016, unless otherwise noted.

§ 250.470 What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?

In addition to complying with all other applicable requirements included in this part, you must provide with your APD all of the following information pertaining to your proposed Arctic OCS exploratory drilling:

(a) A detailed description of:

(1) The environmental, meteorological, and oceanic conditions you expect to encounter at the well site(s);

(2) How you will prepare your equipment, materials, and drilling unit for service in the conditions identified in paragraph (a)(1) of this section, and how your drilling unit will be in compliance with the requirements of § 250.713.

(b) A detailed description of all operations necessary in Arctic OCS conditions to transition the rig from being under way to conducting drilling operations and from ending drilling operations to being under way, as well as any anticipated repair and maintenance plans for the drilling unit and equipment. You should include, among other things, a description of how you plan to:

(1) Recover the subsea equipment, including the marine riser and the lower marine riser package;

(2) Recover the BOP;

(3) Recover the auxiliary sub-sea controls and template;

(4) Lay down the drill pipe and secure the drill pipe and marine riser;

(5) Secure the drilling equipment;

(6) Transfer the fluids for transport or disposal;

(7) Secure ancillary equipment like the draw works and lines;

(8) Refuel or transfer fuel;

(9) Offload waste;

(10) Recover the Remotely Operated Vehicles;

(11) Pick up the oil spill prevention booms and equipment; and

(12) Offload the drilling crew.

(c) A description of well-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of the well, including but not limited to the following:

(1) When you will spud the particular well (*i.e.*, begin drilling operations at the well site) identified in the APD;

(2) How long you will take to drill the well;

(3) Anticipated depths and geologic targets, with timelines;

(4) When you expect to set and cement each string of casing;

(5) When and how you would log the well;

(6) Your plans to test the well;

(7) When and how you intend to abandon the well, including specifically addressing your plans for how to move the rig off location and how you will meet the requirements of § 250.720(c);

(8) A description of what equipment and vessels will be involved in the process of temporarily abandoning the well due to ice; and

(9) An explanation of how you will integrate these elements into your overall program.

(d) A detailed description of your weather and ice forecasting capability for all phases of the drilling operation, including:

(1) How you will ensure your continuous awareness of potential weather and ice hazards at, and during transition between, wells;

(2) Your plans for managing ice hazards and responding to weather events; and

(3) Verification that you have the capabilities described in your BOEM-approved EP.

(e) A detailed description of how you will comply with the requirements of § 250.472.

(f) A statement that you own, or have a contract with a provider for, source control and containment equipment (SCCE), which is capable of controlling and/or containing a worst case discharge, as described in your BOEM-approved EP, when proposing to use a MODU to conduct exploratory drilling operations on the Arctic OCS. The following information must be included in your SCCE submittal:

(1) A detailed description of your or your contractor's SCCE capability to stop or contain flow from an out-of-control well, including your operating assumptions and limitations; your access to and ability to deploy, in accordance with § 250.471, all necessary SCCE; and your ability to evaluate the performance of the well design to determine how you can achieve a full shut-in without having reservoir fluids discharged into the environment;

(2) An inventory of the local and regional SCCE, supplies, and services that you own or for which you have a contract with a provider. You must identify each supplier of such equipment and services and provide their locations and telephone numbers;

(3) Where applicable, proof of contracts or membership agreements with cooperatives, service providers, or other contractors who will provide you with the necessary SCCE or related supplies and services if you do not possess them. 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 while you are drilling below or working below the surface casing;

(4) A detailed description of the procedures you plan to use to inspect, test, and maintain your SCCE; and

(5) A detailed description of your plan to ensure that all members of your operating team, who are responsible for operating the SCCE, have received the necessary training to deploy and operate such equipment in Arctic OCS conditions and demonstrate ongoing proficiency in source control operations. You must also identify and include the dates of prior and planned training.

(g) Where it does not conflict with other requirements of this subpart, and except as provided in paragraphs (g)(1) through (11) of this section, you must comply with the requirements of API RP 2N, Third Edition ''Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions'' (incorporated by reference as specified in § 250.198), and provide a detailed description of how you will utilize the best practices included in API RP 2N during your exploratory drilling operations. You are not required to incorporate the following sections of API RP 2N into your drilling operations:

(1) Sections 6.6.3 through 6.6.4;

(2) The foundation recommendations in Section 8.4;

(3) Section 9.6;

(4) The recommendations for permanently moored systems in Section 9.7;

(5) The recommendations for pile foundations in Section 9.10;

(6) Section 12;

(7) Section 13.2.1;

(8) Sections 13.8.1.1, 13.8.2.1, 13.8.2.2, 13.8.2.4 through 13.8.2.7;

(9) Sections 13.9.1, 13.9.2, 13.9.4 through 13.9.8;

(10) Sections 14 through 16; and

(11) Section 18.

§ 250.471 What are the requirements for Arctic OCS source control and containment?

You must meet the following requirements for all exploration wells drilled on the Arctic OCS:

(a) If you use a MODU when drilling below or working below the surface casing, you must have access to the following SCCE capable of stopping or capturing the flow of an out-of-control well:

(1) A capping stack, positioned to ensure that it will arrive at the well location within 24 hours after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section;

(2) A cap and flow system, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The cap and flow system must be designed to capture at least the amount of hydrocarbons equivalent to the calculated worst case discharge rate referenced in your BOEM-approved EP; and

(3) A containment dome, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The containment dome must have the capacity to pump fluids without relying on buoyancy.

(b) You must conduct a monthly stump test of dry-stored capping stacks. If you use a pre-positioned capping stack, you must conduct a stump test prior to each installation on each well.

(c) As required by § 250.465(a), if you propose to change your well design, you must submit an APM. For Arctic OCS operations, your APM must include a reevaluation of your SCCE capabilities for any new Worst Case Discharge (WCD) rate, and a demonstration that your SCCE capabilities will meet the criteria in § 250.470(f) under the changed well design.

(d) You must conduct tests or exercises of your SCCE, including deployment of your SCCE, when directed by the Regional Supervisor.

(e) You must maintain records pertaining to testing, inspection, and maintenance of your SCCE for at least 10 years and make the records available to any authorized BSEE representative upon request.

(f) You must maintain records pertaining to the use of your SCCE during testing, training, and deployment activities for at least 3 years and make the records available to any authorized BSEE representative upon request.

(g) Upon a loss of well control, you must initiate transit of all SCCE identified in paragraph (a) of this section to the well.

(h) You must deploy and use SCCE when directed by the Regional Supervisor.

(i) Operators may request approval of alternate procedures or equipment to the SCCE requirements of subparagraph (a) of this section in accordance with § 250.141. The operator must show and document that the alternate procedures or equipment will provide a level of safety and environmental protection that will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be capable of stopping or capturing the flow of an out-of-control well.

§ 250.472 What are the relief rig requirements for the Arctic OCS?

(a) In the event of a loss of well control, the Regional Supervisor may direct you to drill a relief well using the relief rig able to kill and permanently plug an out-of-control well as described in your APD. Your relief rig must comply with all other requirements of this part pertaining to drill rig characteristics and capabilities, and it must be able to drill a relief well under anticipated Arctic OCS conditions.

(b) When you are drilling below or working below the surface casing during Arctic OCS exploratory drilling operations, you must have access to a relief rig, different from your primary drilling rig, staged in a location such that it can arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, but no later than 45 days after the loss of well control.

(c) Operators may request approval of alternative compliance measures to the relief rig requirement in accordance with § 250.141. The operator must show and document that the alternate compliance measure will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate compliance measure will be able to kill and permanently plug an out-of-control well.

§ 250.473 What must I do to protect health, safety, property, and theenvironment while operating on the Arctic OCS?

In addition to the requirements set forth in § 250.107, when conducting exploratory drilling operations on the Arctic OCS, you must protect health, safety, property, and the environment by using the following:

(a) Equipment and materials that are rated or de-rated for service under conditions that can be reasonably expected during your operations; and

(b) Measures to address human factors associated with weather conditions that can be reasonably expected during your operations including, but not limited to, provision of proper attire and equipment, construction of protected work spaces, and management of shifts.

HYDROGEN SULFIDE

§ 250.490 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 BSEE 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 Manager

for approval. Do not begin operations before the District Manager 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, American National Standard for Respiratory Protection (as specified in § 250.198);

(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 Manager 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 Manager 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 Manager 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 BSEE 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 Manager 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 Manager 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_2concentration 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 in conformance with ANSI Z88.2 (as specified in § 250.198).

(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 Manager 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 BSEE in the event of an H_2S release?* You must notify BSEE 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 OCS facility. You must report these gas releases to

the District Manager immediately by oral communication, with a written follow-up report within 15 days, pursuant to §§ 250.188 through 250.190.

(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 § 250.300(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) of this section. You must also follow the requirements of § 250.1164. 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 Manager. 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 in conformance with NACE Standard MR0175–03 (as specified in § 250.198).

(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 non-restricted 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 Manager.

(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 Manager an analysis of the anticipated H_2S content of the water at the final treatment vessel and at the discharge point. The District Manager may require that the water be treated for removal of H_2S. The District Manager 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.

Subpart E—Oil and Gas Well-Completion Operations

§ 250.500 General requirements.

Well-completion operations must 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. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26021, Apr. 29, 2016]

§ 250.501 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.

§ 250.502 [Reserved]

§ 250.503 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.

§ 250.504 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 § 250.490 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 § 250.490 of this part as well as the appropriate requirements of this subpart.

§ 250.505 Subsea completions.

No subsea well completion shall be commenced until the lessee obtains written approval from the District Manager in accordance with § 250.513 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.

§§ 250.506–250.508 [Reserved]

§ 250.509 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.

§ 250.510 Diesel engine air intakes.

Diesel engine air intakes must be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with either remote operated manual or automatic-shutdown devices. Diesel engines that are not continuously attended must be equipped with automatic-shutdown devices.

§ 250.511 Traveling-block safety device.

All units being used for well-completion operations that have both a traveling block and a crown block must be equipped with a safety device that is designed to prevent the traveling block from striking the crown block. The device must be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check must be entered in the operations log.

§ 250.512 Field well-completion rules.

When geological and engineering information available in a field enables the District Manager to determine specific operating requirements, field well-completion rules may be established on the District Manager'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 Manager or upon the request of a lessee.

§ 250.513 Approval and reporting of well-completion operations.

(a) No well-completion operation may begin until the lessee receives written approval from the District Manager. If completion is planned and the data are available at the time you submit the Application for Permit to Drill and Supplemental APD Information Sheet (Forms BSEE–0123 and BSEE–0123S), you may request approval for a well-completion on those forms (see §§ 250.410 through 250.418 of this part). If the District Manager has not approved the completion or if the completion objective or plans have significantly changed, you must submit an Application for Permit to Modify (Form BSEE–0124) for approval of such operations.

(b) You must submit the following with Form BSEE–0124 (or with Form BSEE–0123; Form BSEE–0123S):

(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;

(4) All applicable information required in § 250.731.

(5) 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 § 250.490 of this part; and

(6) Payment of the service fee listed in § 250.125.

(c) Within 30 days after completion, you must submit to the District Manager an End of Operations Report (Form BSEE–0125), including a schematic of the tubing and subsurface equipment.

(d) You must submit public information copies of Form BSEE–0125 according to § 250.186.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

§ 250.514 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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

§§ 250.515–250.517 [Reserved]

§ 250.518 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) When the tree is installed, you must equip wells to monitor for casing pressure according to the following chart:

If you . . .	you must equip . . .	so you can monitor . . .
(1) fixed platform wells,	the wellhead,	all annuli (A, B, C, D, *etc.,* annuli).
(2) subsea wells,	the tubing head,	the production casing annulus (A annulus).
(3) hybrid * wells,	the surface wellhead,	all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure.

* Characterized as a well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree.

(c) 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.

(d) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§ 250.810 through 250.839.

(e) When installed, packers and bridge plugs must meet the following:

(1) The uppermost permanently installed packer and all permanently installed bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198);

(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

(g) You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012, as amended at 81 FR 26021, Apr. 29, 2016; 81 FR 61918, Sept. 7, 2016; 84 FR 21976, May 15, 2019]

CASING PRESSURE MANAGEMENT

§ 250.519 What are the requirements for casing pressure management?

Once you install your wellhead, you must meet the casing pressure management requirements of API RP 90 (as incorporated by reference in § 250.198) and the requirements of §§ 250.519 through 250.531. If there is a conflict between API RP 90 and the casing pressure requirements of this subpart, you must follow the requirements of this subpart.

[84 FR 21976, May 15, 2019]

§ 250.520 How often do I have to monitor for casing pressure?

You must monitor for casing pressure in your well according to the following table:

If you have . . .	you must monitor . . .	with a minimum one pressure data point recorded per . . .
(a) fixed platform wells,	monthly,	month for each casing.
(b) subsea wells,	continuously,	day for the production casing.
(c) hybrid wells,	continuously,	day for each riser and/or the production casing.
(d) wells operating under a casing pressure request on a manned fixed platform,	daily,	day for each casing.
(e) wells operating under a casing pressure request on an unmanned fixed platform,	weekly,	week for each casing.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.521 When do I have to perform a casing diagnostic test?

(a) You must perform a casing diagnostic test within 30 days after first observing or imposing casing pressure according to the following table:

If you have a . . .	you must perform a casing diagnostic test if . . .
(1) fixed platform well,	the casing pressure is greater than 100 psig.
(2) subsea well,	the measurable casing pressure is greater than the external hydrostatic pressure plus 100 psig measured at the subsea wellhead.
(3) hybrid well,	a riser or the production casing pressure is greater than 100 psig measured at the surface.

(b) You are exempt from performing a diagnostic pressure test for the production casing on a well operating under active gas lift.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.522 How do I manage the thermal effects caused by initial production on a newly completed or recompleted well?

A newly completed or recompleted well often has thermal casing pressure during initial startup. Bleeding casing pressure during the startup process is considered a normal and necessary operation to manage thermal casing pressure; therefore, you do not need to evaluate these operations as a casing diagnostic test. After 30 days of continuous production, the initial production startup operation is complete and you must perform casing diagnostic testing as required in §§ 250.521 and 250.523.

[84 FR 21976, May 15, 2019]

§ 250.523 When do I have to repeat casing diagnostic testing?

Casing diagnostic testing must be repeated according to the following table:

When . . .	you must repeat diagnostic testing . . .
(a) your casing pressure request approved term has expired,	immediately.
(b) your well, previously on gas lift, has been shut-in or returned to flowing status without gas lift for more than 180 days,	immediately on the production casing (A annulus). The production casing (A annulus) of wells on active gas lift are exempt from diagnostic testing.
(c) your casing pressure request becomes invalid,	within 30 days.
(d) a casing or riser has an increase in pressure greater than 200 psig over the previous casing diagnostic test,	within 30 days.
(e) after any corrective action has been taken to remediate undesirable casing pressure, either as a result of a casing pressure request denial or any other action,	within 30 days.
(f) your fixed platform well production casing (A annulus) has pressure exceeding 10 percent of its minimum internal yield pressure (MIYP), except for production casings on active gas lift,	once per year, not to exceed 12 months between tests.
(g) your fixed platform well's outer casing (B, C, D, *etc.,* annuli) has a pressure exceeding 20 percent of its MIYP,	once every 5 years, at a minimum.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.524 How long do I keep records of casing pressure and diagnostic tests?

Records of casing pressure and diagnostic tests must be kept at the field office nearest the well for a minimum of 2 years. The last casing diagnostic test for each casing or riser must be retained at the field office nearest the well until the well is abandoned.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.525 When am I required to take action from my casing diagnostic test?

You must take action if you have any of the following conditions:

(a) Any fixed platform well with a casing pressure exceeding its maximum allowable wellhead operating pressure (MAWOP);

(b) Any fixed platform well with a casing pressure that is greater than 100 psig and that cannot bleed to 0 psig through a ½-inch needle valve within 24 hours, or is not bled to 0 psig during a casing diagnostic test;

(c) Any well that has demonstrated tubing/casing, tubing/riser, casing/casing, riser/casing, or riser/riser communication;

(d) Any well that has sustained casing pressure (SCP) and is bled down to prevent it from exceeding its MAWOP, except during initial startup operations described in § 250.522;

(e) Any hybrid well with casing or riser pressure exceeding 100 psig; or

(f) Any subsea well with a casing pressure 100 psig greater than the external hydrostatic pressure at the subsea wellhead.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012; 84 FR 21976, May 15, 2019]

§ 250.526 What do I submit if my casing diagnostic test requires action?

Within 14 days after you perform a casing diagnostic test requiring action under § 250.525:

You must submit either . . .	to the appropriate . . .	and it must include . . .	You must also . . .
(a) a notification of corrective action; or,	District Manager and copy the Regional Supervisor, Field Operations,	requirements under § 250.527,	submit an Application for Permit to Modify or Corrective Action Plan within 30 days of the diagnostic test.
(b) a casing pressure request,	Regional Supervisor, Field Operations,	requirements under § 250.528.	

[84 FR 21976, May 15, 2019]

§ 250.527 What must I include in my notification of corrective action?

The following information must be included in the notification of corrective action:

(a) Lessee or Operator name;

(b) Area name and OCS block number;

(c) Well name and API number; and

(d) Casing diagnostic test data.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.528 What must I include in my casing pressure request?

The following information must be included in the casing pressure request:

(a) API number;

(b) Lease number;

(c) Area name and OCS block number;

(d) Well number;

(e) Company name and mailing address;

(f) All casing, riser, and tubing sizes, weights, grades, and MIYP;

(g) All casing/riser calculated MAWOPs;

(h) All casing/riser pre-bleed down pressures;

(i) Shut-in tubing pressure;

(j) Flowing tubing pressure;

(k) Date and the calculated daily production rate during last well test (oil, gas, basic sediment, and water);

(l) Well status (shut-in, temporarily abandoned, producing, injecting, or gas lift);

(m) Well type (dry tree, hybrid, or subsea);

(n) Date of diagnostic test;

(o) Well schematic;

(p) Water depth;

(q) Volumes and types of fluid bled from each casing or riser evaluated;

(r) Type of diagnostic test performed:

(1) Bleed down/buildup test;

(2) Shut-in the well and monitor the pressure drop test;

(3) Constant production rate and decrease the annular pressure test;

(4) Constant production rate and increase the annular pressure test;

(5) Change the production rate and monitor the casing pressure test; and

(6) Casing pressure and tubing pressure history plot;

(s) The casing diagnostic test data for all casing exceeding 100 psig;

(t) Associated shoe strengths for casing shoes exposed to annular fluids;

(u) Concentration of any H_2S that may be present;

(v) Whether the structure on which the well is located is manned or unmanned;

(w) Additional comments; and

(x) Request date.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.529 What are the terms of my casing pressure request?

Casing pressure requests are approved by the Regional Supervisor, Field Operations, for a term to be determined by the Regional Supervisor on a case-by-case basis. The Regional Supervisor may impose additional restrictions or requirements to allow continued operation of the well.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

§ 250.530 What if my casing pressure request is denied?

(a) If your casing pressure request is denied, then the operating company must submit plans for corrective action to the respective District Manager

within 30 days of receiving the denial. The District Manager will establish a specific time period in which this corrective action will be taken. You must notify the respective District Manager within 30 days after completion of your corrected action.

(b) You must submit the casing diagnostic test data to the appropriate Regional Supervisor, Field Operations, within 14 days of completion of the diagnostic test required under § 250.523(e).

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012, as amended at 84 FR 21976, May 15, 2019]

§ 250.531 When does my casing pressure request approval become invalid?

A casing pressure request becomes invalid when:

(a) The casing or riser pressure increases by 200 psig over the approved casing pressure request pressure;

(b) The approved term ends;

(c) The well is worked-over, sidetracked, redrilled, recompleted, or acid stimulated;

(d) A different casing or riser on the same well requires a casing pressure request; or

(e) A well has more than one casing operating under a casing pressure request and one of the casing pressure requests become invalid, then all casing pressure requests for that well become invalid.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Subpart F—Oil and Gas Well-Workover Operations

§ 250.600 General requirements.

Well-workover operations must 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. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26021, Apr. 29, 2016]

§ 250.601 Definitions.

When used in this subpart, the following terms shall have the meanings given below:

Expected surface pressure means the highest pressure predicted to be exerted upon the surface of a well. In calculating expected surface pressure, you must consider reservoir pressure as well as applied surface pressure.

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.

(m) Acid treatments.

Workover operations mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21976, May 15, 2019]

§ 250.602 [Reserved]

§ 250.603 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.

§ 250.604 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 § 250.490 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 § 250.490 of this part as well as the appropriate requirements of this subpart.

§ 250.605 Subsea workovers.

No subsea well-workover operation including routine operations shall be commenced until the lessee obtains written approval from the District Manager in accordance with § 250.613 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.

§§ 250.606–250.608 [Reserved]

§ 250.609 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.

§ 250.610 Diesel engine air intakes.

You must equip diesel engine air intakes with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with remotely operated, manual, or automatic shutdown devices. Diesel engines that are not continuously attended must be equipped with automatic shutdown devices.

[81 FR 36149, June 6, 2016]

§ 250.611 Traveling-block safety device.

You must equip all units being used for well-workover operations that have both a traveling block and a crown block with a safety device that is designed to prevent the traveling block from striking the crown block. You must check the device for proper operation weekly and after each drill-line slipping operation. You must enter the results of the operational check in the operations log.

[81 FR 36149, June 6, 2016]

§ 250.612 Field well-workover rules.

When geological and engineering information available in a field enables the District Manager to determine specific operating requirements, field well-workover rules may be established on the District Manager'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 Manager or upon the request of a lessee.

§ 250.613 Approval and reporting for well-workover operations.

(a) No well-workover operation except routine ones, as defined in § 250.601 of this part, shall begin until the lessee receives written approval from the District Manager. Approval for these operations must be requested on Form BSEE–0124, Application for Permit to Modify.

(b) You must submit the following with Form BSEE–0124:

(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;

(3) All information required in § 250.731.

(4) Where the well-workover is in a zone known to contain H_2S or a zone where the presence of H2S is unknown, information pursuant to § 250.490 of this part; and

(5) Payment of the service fee listed in § 250.125.

(c) The following additional information shall be submitted with Form BSEE–0124 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 BSEE–0124, Application for Permit to Modify, shall be submitted to the District Manager, 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 BSEE–0125, End of Operations Report, shall be submitted to the District Manager and shall include a new schematic of the tubing subsurface equipment if any subsurface equipment has been changed.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50895, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

§ 250.614 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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50895, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

§§ 250.615–250.618 [Reserved]

§ 250.619 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) When reinstalling the tree, you must:

(1) Equip wells to monitor for casing pressure according to the following chart:

If you have . . .	you must equip . . .	so you can monitor . . .
(i) fixed platform wells,	the wellhead,	all annuli (A, B, C, D, *etc.,* annuli).
(ii) subsea wells,	the tubing head,	the production casing annulus (A annulus).
(iii) hybrid* wells,	the surface wellhead,	all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure.

*Characterized as a well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree.

(2) Follow the casing pressure management requirements in subpart E of this part.

(c) 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.

(d) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§ 250.810 through 250.839.

(e) If you pull and reinstall packers and bridge plugs, you must meet the following requirements:

(1) The uppermost permanently installed packer and all permanently installed bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198).

(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

(g) You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50895, Aug. 22, 2012, as amended at 81 FR 26021, Apr. 29, 2016; 81 FR 61918, Sept. 7, 2016; 84 FR 21976, May 15, 2019]

§ 250.620 Wireline operations.

The lessee shall comply with the following requirements during routine, as defined in § 250.601 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50895, Aug. 22, 2012]

Subpart G—Well Operations and Equipment

SOURCE: 81 FR 26022, Apr. 29, 2016, unless otherwise noted.

GENERAL REQUIREMENTS

§ 250.700 What operations and equipment does this subpart cover?

This subpart covers operations and equipment associated with drilling,

completion, workover, and decommissioning activities. This subpart includes regulations applicable to drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this part unless explicitly stated otherwise.

§ 250.701 May I use alternate procedures or equipment during operations?

You may use alternate procedures or equipment during operations after receiving approval as described in § 250.141. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE–0123) (see § 250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE–0124). Procedures for obtaining approval of alternate procedures or equipment are described in § 250.141.

§ 250.702 May I obtain departures from these requirements?

You may apply for a departure from these requirements as described in § 250.142. Your request must include a justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM.

§ 250.703 What must I do to keep wells under control?

You must take the necessary precautions to keep wells under control at all times, including:

(a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of subparts O and S of this part;

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and

(f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.

RIG REQUIREMENTS

§ 250.710 What instructions must be given to personnel engaged in well operations?

Prior to engaging in well operations, personnel must be instructed in:

(a) *Hazards and safety requirements.* You must instruct your personnel regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) *Well control.* You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

§ 250.711 What are the requirements for well-control drills?

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in

the well-control plan required by § 250.710.

(a) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.

(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report:

(1) Date, time, and type of drill conducted;

(2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and

(3) The total time to complete the entire drill.

(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

§ 250.712 What rig unit movements must I report?

(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE–0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 24 hours before:

(1) The arrival of a rig unit on location;

(2) The movement of a rig unit to another slot. For movements that will occur less than 24 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or

(3) The departure of a rig unit from the location.

(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.

(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager:

(1) Where the MODU or platform rig is coming from;

(2) The location where the MODU or platform rig will be positioned;

(3) Whether the MODU or platform rig will be manned or unmanned; and

(4) If the location for stacking the MODU or platform rig changes.

(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig.

(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE–0144, Rig Movement Notification Report.

(g) You are not required to report rig unit movements to and from the safe zone during the course of permitted operations.

(h) If a rig unit is already on a well, you are not required to report any additional rig unit movements on that well.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21976, May 15, 2019]

§ 250.713 What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations?

If you plan to use a MODU for well operations, you must provide:

(a) *Fitness requirements.* Information and data to demonstrate the MODU's capability to perform at the proposed location. This information must include the maximum environmental and operational conditions that the MODU is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM, but require you to collect and report this information during operations. Under this circumstance, the District Manager may revoke the approval of the APD or APM if information collected during operations shows

that the MODU is not capable of performing at the proposed location.

(b) *Foundation requirements.* Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed bottom-founded MODU. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM for that well location and conditions, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, or equipment installed on a subsea wellhead. For a moored rig, you must submit a plat of the rig's anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.

(c) *For frontier areas.* (1) If the design of the MODU you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU design. If required, you must obtain a third-party review of your MODU similar to the process outlined in §§ 250.915 through 250.918. You may submit this information before submitting an APD or APM.

(2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of operations to remedy various operational or environmental situations (e.g., vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

(d) *Additional documentation.* You must provide the current Certificate of Inspection (for U.S.-flag vessels) or Certificate of Compliance (for foreign-flag vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) *Dynamically positioned MODU.* If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. At a minimum, your plan must address emergency events caused by storms, currents, station-keeping failures, power failures, and losses of well control. The District Manager may require your plan to include additional events that may require movement of the MODU and other information needed to clarify or further address how the MODU will respond to emergencies or other events.

(f) *Inspection of MODU.* The MODU must be available for inspection by the District Manager before commencing operations and at any time during operations.

(g) *Current monitoring.* For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM:

(1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and

(2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria, such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.

[81 FR 26022, Apr. 29, 2016, as amended at 81 FR 36150, June 6, 2016]

§ 250.714 Do I have to develop a dropped objects plan?

If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:

(a) A description and plot of the path the rig will take while running and pulling the riser;

(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;

(c) Modeling of a dropped object's path with consideration given to

metocean conditions for various material forms, such as a tubular (e.g., riser or casing) and box (e.g., BOP or tree);

(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and

(e) Any additional information required by the District Manager as appropriate to clarify, update, or evaluate your dropped objects plan.

§ 250.715 Do I need a global positioning system (GPS) for all MODUs?

All MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to and during each hurricane season.

(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the MODU moves from its location during a severe storm.

(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.

(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.

(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.

(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.

(f) You must contact the Regional Office and allow real-time access to the MODU location data. When you contact the Regional Office, provide the following:

(1) Name of the lessee and operator with contact information;

(2) MODU name;

(3) Initial date and time; and

(4) How you will provide GPS real-time access.

WELL OPERATIONS

§ 250.720 When and how must I secure a well?

(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with § 250.721.

(1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following:

(i) Evacuation of the rig crew;

(ii) Inability to keep the rig on location;

(iii) Repair to major rig or well-control equipment;

(iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling); or

(v) Impending National Weather Service-named tropical storm or hurricane.

(2) The District Manager may approve alternate procedures or barriers, in accordance with § 250.141, if you do not have time to install the required barriers or if special circumstances occur.

(3) If you unlatch the BOP or LMRP:

(i) Upon relatch of the BOP, you must test according to § 250.734(b)(2), or

(ii) Upon relatch of the LMRP, you must test according to § 250.734(b)(3); and

(iii) You must submit a revised permit with a written statement from an independent third party certifying that the previous certification under § 250.731(c) remains valid and receive District Manager approval before resuming operations.

(b) Before you displace kill-weight fluid from the wellbore and/or riser, thereby creating an underbalanced state, you must obtain approval from the District Manager. To obtain approval, you must submit with your

APD or APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers;

(2) Tests you will conduct to ensure integrity of independent barriers;

(3) BOP procedures you will use while displacing kill-weight fluids; and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

(c) For Arctic OCS exploratory drilling operations, in addition to the requirements of paragraphs (a) and (b) of this section:

(1) If you move your drilling rig off a well prior to completion or permanent abandonment, you must ensure that any equipment left on, near, or in a wellbore that has penetrated below the surface casing is positioned in a manner to:

(i) Protect the well head; and

(ii) Prevent or minimize the likelihood of compromising the down-hole integrity of the well or the effectiveness of the well plugs.

(2) In areas of ice scour you must use a well mudline cellar or an equivalent means of minimizing the risk of damage to the well head and wellbore. BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection provided by a mudline cellar if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks.

(d) You must have the equipment used solely for intervention operations (e.g., tree interface tools) identified, readily available, properly maintained, and available for BSEE inspection upon request. This equipment is required for subsea completed wells with a tree installed, that meet the following conditions:

(1) Have a shut-in tubing pressure that is greater than the hydrostatic pressure of the water column, or

(2) Are not capable of having the annulus monitored.

[81 FR 26022, Apr. 29, 2016, as amended at 81 FR 46563, July 15, 2016; 84 FR 21976, May 15, 2019]

§ 250.721 What are the requirements for pressure testing casing and liners?

(a) You must test each casing string that extends to the wellhead according to the following table:

Casing type	Minimum test pressure
(1) Drive or Structural,	Not required.
(2) Conductor, excluding subsea wellheads,	250 psi.
(3) Surface, Intermediate, and Production,	70 percent of its minimum internal yield.

(b) You must test each drilling liner and liner-top to a pressure at least equal to the anticipated leak-off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.

(c) You must test each production liner and liner-top to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.

(d) The District Manager may approve or require other casing test pressures as appropriate under the circumstances to ensure casing integrity.

(e) If you plan to produce a well, you must:

(1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before perforating the casing or liner; or

(2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before you drill the open-hole section.

(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track, but prior to conducting any completion operations.

(2) You must perform a negative pressure test prior to unlatching the BOP at any point in the well. The negative pressure test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.

(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack as appropriate to demonstrate casing or liner integrity.

(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative pressure test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.

(5) You must document all your test results and make them available to BSEE upon request.

(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must:

(i) Correct the problem and immediately notify the appropriate District Manager; and

(ii) Submit a description of the corrective action taken and receive approval from the appropriate District Manager for the retest.

(7) You must have two barriers in place, as described in § 250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.

(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE–0125).

§ 250.722 What are the requirements for prolonged operations in a well?

If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:

(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must:

(1) Evaluate the well casing with a pressure test, caliper tool, or imaging tool. On a case-by-case basis, the District Manager may require a specific method of evaluation of the effects on the well casing of prolonged operations; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that indicate the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used. District Manager approval is not required to resume operations if you conducted a successful pressure test as approved in your permit. You must document the successful pressure test in the WAR.

(b) If well integrity has deteriorated to a level below minimum safety factors, you must:

(1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that he or she reviewed and approved the proposed changes;

(2) Repair the casing or run another casing string; and

(3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the

District Manager as specified in § 250.721.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21977, May 15, 2019]

§ 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

You must take the following safety measures when you conduct operations with a rig unit on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:

(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;

(b) You must install an emergency shutdown station for the production system near the rig operator's console;

(c) You must shut-in all producible wells located in the affected wellbay below the surface and at the wellhead when:

(1) You move a rig unit or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

(2) You move or skid a rig unit between wells on a platform; or

(3) A MODU moves within 500 feet of a platform. You may resume production once the MODU is in place, secured, and ready to begin operations.

(d) All wells in the same well-bay which are capable of producing hydrocarbons must 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 rig units and related equipment, unless otherwise approved by the District Manager.

(1) 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.

(2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system.

(3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.

(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21977, May 15, 2019]

§ 250.724 What are the real-time monitoring requirements?

(a) When conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's active fluid circulating system; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c) of this section.

(c) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following:

(1) A description of your real-time monitoring capabilities, including the types of the data collected;

(2) A description of how your real-time monitoring data will be transmitted during operations, how the data will be labeled and monitored by qualified personnel, and how the data will be stored as required in §§ 250.740 and 250.741;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data;

(4) The qualifications of the personnel monitoring the data;

(5) Your procedures for, and methods of, communication between rig personnel and the monitoring personnel; and

(6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig personnel and monitoring personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring capabilities or communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

[84 FR 21977, May 15, 2019]

BLOWOUT PREVENTER (BOP) SYSTEM REQUIREMENTS

§ 250.730 What are the general requirements for BOP systems and system components?

(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be determined at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system must be capable of closing and sealing the wellbore in the event of flow due to a kick, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements:

(1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API Standard 53 and the requirements of this subpart, you must follow the requirements of this subpart.

(2) The provisions of the following industry standards (all incorporated by reference in § 250.198) that apply to BOP systems:

(i) ANSI/API Spec. 6A;

(ii) ANSI/API Spec. 16A;

(iii) ANSI/API Spec. 16C;

(iv) API Spec. 16D; and

(v) ANSI/API Spec. 17D.

(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, at the proposed regulator settings of the BOP control system.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will require changes to your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, applicable Original Equipment Manufacturer's (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed applicable OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, (incorporated by reference in § 250.198), and:

(1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs (OORP), unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification

of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause of the failure, and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. If you cannot complete the investigation and analysis within the specified time, you must submit an extension request detailing how you will complete the investigation and analysis to BSEE for approval. You must submit the extension request to the Chief, OORP.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

(4) Submit notices and reports to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166. BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an ANSI/API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO/IEC 17021–1 (as incorporated by reference in § 250.198).

(1) BSEE may consider accepting equipment manufactured under quality assurance programs other than ANSI/API Spec. Q1, provided you submit a request to the Chief, OORP for approval, containing relevant information about the alternative program.

(2) You must submit this request to the Chief, OORP; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.

[84 FR 21977, May 15, 2019]

§ 250.731 What information must I submit for BOP systems and system components?

For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.

You must submit:	Including:
(a) A complete description of the BOP system and system components,	(1) Pressure ratings of BOP equipment;
	(2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures);
	(3) Rated capacities for liquid and gas for the fluid-gas separator system;
	(4) Control fluid volumes needed to close, seal, and open each component;
	(5) Control system pressure and regulator settings needed to close each ram BOP under MASP as defined for the operation;
	(6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles);

You must submit:	Including:
	(7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).
(b) Schematic drawings, ...	(1) The inside diameter of the BOP stack; (2) Number and type of preventers (including blade type for shear ram(s)); (3) All locking devices; (4) Size range for variable bore ram(s); (5) Size of fixed ram(s); (6) All control systems with all alarms and set points labeled, including pods; (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP); (8) Associated valves of the BOP system; (9) Control station locations; and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.
(c) Certification by an independent third party,	Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system; and (4) If using a subsea BOP, a BOP in an HPHT environment as defined in § 250.804(b), or a surface BOP on a floating facility, the BOP has not been compromised or damaged from previous service.
(d) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems,	A listing of the functions with their sequences and timing.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21978, May 15, 2019]

§ 250.732 What are the independent third party requirements for BOP systems and system components?

(a) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third party and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

You must submit verification and documentation related to:	That:
(1) Shear testing, ...	(i) Demonstrates that the BOP will shear the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well; (ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards; (iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well; (iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram; (v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well; and (vi) Includes relevant testing results.
(2) Pressure integrity testing for sealing components, and	(i) Shows that testing is conducted after the shearing is completed and prior to opening the component; (ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 5 minutes; and (iii) Includes all relevant test results.

You must submit verification and documentation related to:	That:
(3) Calculations	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(b) The independent third-party must be a technical classification society, a licensed professional engineering firm, or a registered professional engineer capable of providing the required certifications and verifications.

(c) For wells in an HPHT environment, as defined by § 250.804(b), you must submit verification by an independent third party that it conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the independent third party access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

You must submit:	Including:
(1) Verification that the independent third party conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,	
(2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible,	(i) Identification of all reasonable potential modes of failure; and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and	
(4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.	For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

(d) You must make all documentation that demonstrates compliance with the requirements of this section available to BSEE upon request.

[84 FR 21978, May 15, 2019]

§ 250.733 What are the requirements for a surface BOP stack?

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind shear rams, and two BOPs equipped with pipe rams.

(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. Prior to April 29, 2021, if your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under

MASP, as defined for the operation, except for tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(b) If you plan to use a surface BOP on a floating production facility you must:

(1) On new floating production facilities installed after April 29, 2021, that include a surface BOP, follow the BOP requirements in § 250.734(a)(1).

(2) For risers installed after July 28, 2016, use a dual bore riser configuration before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198), including appropriate design for the maximum anticipated operating and environmental conditions.

(i) For a dual bore riser configuration, the annulus between the risers must be monitored for pressure during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.

(ii) The inner riser for a dual riser configuration is subject to the requirements at § 250.721 for testing the casing or liner.

(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

(e) Additional requirements for surface BOP systems used in well-completion, workover, and decommissioning operations. The minimum BOP system for well-completion, workover, and decommissioning operations must meet the appropriate standards from the following table:

When . . .	The minimum BOP stack must include . . .
(1) The expected pressure is less than 5,000 psi,	Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams.
(2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings,	Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams.
(3) You handle multiple tubing strings simultaneously,	Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams.
(4) You use a tapered drill pipe, work string, or tubing,	At least one set of pipe rams that are capable of sealing around each size of drill pipe, work string, or tubing. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill pipe, work string, or tubing. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a surface BOP on a floating facility,	The elements required by § 250.733(b)(1) of this part.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21979, May 15, 2019]

§ 250.734 What are the requirements for a subsea BOP system?

(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.

When operating with a subsea BOP system, you must:	Additional requirements:
(1) Have at least five remote-controlled, hydraulically operated BOPs;	You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the dual ram requirement, you must comply with this requirement no later than April 29, 2021. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).
(2) Have an operable redundant pod control system to ensure proper and independent operation of the BOP system;	
(3) Have the accumulator capacity, to provide fast closure of the BOP components and to operate all critical functions;	The accumulator capacity must: (i) Close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability to perform ROV functions within the required times outlined in API Standard 53 with ROV or flying leads. (iii) Have bottles located subsea for the autoshear and deadman (which may be shared between those two systems) to secure the wellbore. These bottles may also be utilized to perform the secondary control system functions (e.g., ROV or acoustic functions). (iv) Perform under MASP conditions as defined for the operation.
(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;	You must have the ROV intervention capability to close each shear ram, ram locks, one pipe ram, and disconnect the LMRP under MASP conditions as defined for the operation. You must be capable of performing these functions in the response times outlined in API Standard 53 (as incorporated by reference in § 250.198). The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).
(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must examine all ROV-related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations;	The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.
(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs;	(i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Autoshear/deadman functions and an EDS mode must close, at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay when closing your two shear rams in order to provide maximum sealing efficiency.

When operating with a subsea BOP system, you must:	Additional requirements:
(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions;	If you choose to use an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic control system will function in the proposed environment and conditions. The District Manager may require additional information as appropriate to clarify or evaluate the acoustic control system information provided in your demonstration.
(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions;	You must incorporate enable buttons, or a similar feature, on control panels to ensure two-handed operation for all critical functions.
(9) Clearly label all control panels for the subsea BOP system;	Label other BOP control panels, such as hydraulic control panel.
(10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system;	The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;	Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subparts O and S; and (ii) A comprehensive knowledge of BOP hardware and control systems.
(12) Before removing the marine riser, displace the fluid in the riser with seawater;	You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).
(13) Install the BOP stack in a well cellar when in an ice-scour area;	Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(14) Install at least two side outlets for a choke line and two side outlets for a kill line;	(i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. iv) You must install a side outlet below the lowest sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.
(15) Install a gas bleed line with two valves for the annular preventer no later than April 30, 2018;	(i) The valves must hold pressure from both directions; (ii) If you have dual annulars, you must install the gas bleed line below the upper annular.
(16) Use a BOP system that has the following mechanisms and capabilities;	(i) No later than May 1, 2023, you must have the capability to position the entire pipe completely within the area of the shearing blade. This capability cannot be a separate ram BOP or annular preventer, but you may use those during a planned shear. (ii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

(b) If you suspend operations to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised permit with a written statement from an independent third party documenting the repairs and certifying that the previous certification in § 250.731(c) remains valid;

(2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4), including deadman in accordance with § 250.737(d)(12)(vi). If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of § 250.737;

(3) Upon relatch of the LMRP, you must test according to the following:

(i) Pressure test riser connector/gasket in accordance with § 250.737(b) and (c);

(ii) Pressure test choke and kill stabs at LMRP/BOP interface in accordance with § 250.737(b) and (c);

(iii) Full function test of both pods and both control panels;

(iv) Verify acoustic pod communication (if equipped); and

(v) Deadman test with pressure test in accordance with § 250.737(d)(12)(vi).

(4) Receive approval from the District Manager.

(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21980, May 15, 2019]

§ 250.735 What associated systems and related equipment must all BOP systems include?

All BOP systems must include the following associated systems and related equipment:

(a) An accumulator system (as specified in API Standard 53, incorporated by reference in § 250.198). Your accumulator system must have the fluid volume capacity and appropriate precharge pressures in accordance with API Standard 53. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;

(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;

(d) The choke line(s) installed above the bottom well-control ram;

(e) The kill line must be installed beneath at least one well-control ram, and may be installed below the bottom ram;

(f) A fill-up line above the uppermost BOP;

(g) Locking devices for all BOP sealing rams (*i.e.*, blind shear rams, pipe rams and variable bore rams), as follows:

(1) For subsea BOPs, hydraulic locking devices must be installed on all sealing rams;

(2) For surface BOPs:

(i) Remotely-operated locking devices must be installed on blind shear rams no later than April 29, 2019;

(ii) Manual or remotely-operated locking devices must be installed on pipe rams and variable bore rams; and

(h) A wellhead assembly with a RWP that exceeds the maximum anticipated wellhead pressure.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

§ 250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a RWP at least as great as the RWP of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a RWP at least as great as the RWP of the ram BOPs.

(d) You must use the following BOP equipment with a RWP and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in § 250.198);

(2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;

(3) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe;

(4) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe;

(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole. For subsea BOPs, the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string;

(6) All required manual and remote-controlled kelly-type valves, drill-string safety valves, and comparable-type valves (*i.e.*, kelly-type valve in a top-drive system) that are essentially full opening; and

(7) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

§ 250.737 What are the BOP system testing requirements?

Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

(a) *Pressure test frequency*. You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind shear rams) following the conclusion of the previous test;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) In lieu of meeting the schedule established in paragraph (a)(2) of this section, you may request that BSEE approve a 21-day BOP testing frequency. To obtain BSEE approval, you must submit a request to the appropriate BSEE Regional Supervisor, District Field Operations. Your request must demonstrate that you have developed a BOP health monitoring plan that includes certain system capabilities. As long as your plan is consistent with recognized engineering and industry practice, BSEE will approve your request if it includes the following:

(i) Condition monitoring tools, including continuous surveillance of sensor readings from the BOP control system, real-time condition analysis and displays, functional pressure signal analysis, historical sensor data;

(ii) Failure propagation analysis;

(iii) A failure tracking and resolution system that includes detailed failure reports and identification of recurring problems; and

(iv) Submission of quarterly reports of the data collected pursuant to paragraphs (a)(4)(i)(iii) to the BSEE Regional Supervisor, District Field Operations.

(5) The District Manager may require more frequent testing if conditions or your BOP performance warrant.

(b) *Pressure test procedures*. When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component (excluding test rams and non-sealing shear rams). You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph (b) outlines your pressure test requirements.

You must conduct a . . .	According to the following procedures . . .
(1) Low-pressure test	All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.
(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components.	(i) The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your permit. (ii) The blind shear ram (BSR) must be tested to: (A) MASP plus 500 psi for the hole section to which it is exposed; or (B) Full well MASP plus 500 psi on initial latch up and all subsequent BSR pressure tests can be done to the casing/liner test pressure for the applicable hole section. (iii) The choke and kill side outlet valves must be tested to, except as provided in paragraph (d)(13) of this section: (A) MASP plus 500 psi for the hole section to which it is exposed; or (B) Full well MASP plus 500 psi on initial latch up and all subsequent pressure tests can be done to the casing/liner test pressure for the applicable hole section.
(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP.	The high pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD or APM.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours, or on a digital recorder. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, *i.e.*, cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

(d) *Additional test requirements.* You must meet the following additional BOP testing requirements:

You must . . .	Additional requirements . . .
(1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198).	If there is a conflict between API Standard 53, testing requirements and this section, you must follow the requirements of this section.
(2) Use water to test a surface BOP system on the initial test. You may use drilling/completion/workover fluids to conduct subsequent tests of a surface BOP system.	(i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing.
(3) Stump test a subsea BOP system before installation.	(i) You must use water to conduct this test. You may use drilling/completion/workover fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. (iv) You must verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (v) You must follow paragraphs (b) and (c) of this section. Pressure testing of each ram and annular component is only required once.
(4) Perform an initial subsea BOP test	(i) You must begin the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams and annulars according to paragraphs (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must confirm closure of the selected ram through the ROV hot stab with a 1,000 psi pressure test for 5 minutes.

You must . . .	Additional requirements . . .
(5) Alternate tests between control stations	(i) For two complete BOP control stations you must: (A) Designate a primary and secondary station; (B) Alternate testing between the primary and secondary control stations on a weekly basis; and (C) For a subsea BOP, develop an alternating testing schedule to ensure the primary and secondary control stations will function each pod. (ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests.
(6) Pressure test variable bore-pipe ram BOPs against pipe sizes according to API Standard 53, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	
(7) Pressure test annular type BOPs against pipe sizes according to API Standard 53.	
(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.	
(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests.	
(10) Function test shear ram(s) BOPs every 14 days.	If BSEE approves your request to utilize a 21-day BOP test frequency pursuant to § 250.737(a)(4), you may function test shear ram(s) BOPs every 21 days in accordance with the terms of that approval.
(11) Actuate safety valves assembled with proper casing connections before running casing.	
(12) Function test autoshear/deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor.	(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event. (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation. (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. (iv) Following the deadman system test on the seafloor you must document the final remaining pressure of the subsea accumulator system. (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures. (vi) You must confirm closure of the BSR(s) with a 1,000 psi pressure test for 5 minutes. (vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram. (viii) You must document all your test results and make them available to BSEE upon request.
(13) Pressure test the choke and kill side outlet valves.	According to paragraph (b) of this section, except as follows: (i) Test the wellbore side of the choke and kill side outlet valves above the uppermost pipe ram to the approved annular test pressure. Choke and kill side outlet valves below the uppermost pipe ram must be tested to MASP plus 500 psi for the applicable hole section. (ii) For the 30 day BSR testing, test the wellbore side of the choke and kill side outlet valves between the upper most pipe ram and the upper most ram, to the casing/liner test pressure or annular test pressure, whichever is greater. (iii) For BOPs with only one choke and kill side outlet valve, you are only required to pressure test the choke and kill side outlet valves from the wellbore side.

(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the District Manager at least 72 hours in advance, to ensure that a BSEE representative will have access to the location to witness any testing.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

§ 250.738 What must I do in certain situations involving BOP equipment or systems?

The table in this section describes actions that you must take when certain situations occur with BOP systems.

If you encounter the following situation:	Then you must . . .
(a) BOP equipment does not hold the required pressure during a test;	Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, on the daily report as required in § 250.746.
(b) Need to repair, replace, or reconfigure a surface BOP or subsea BOP system;	(1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) Submit a revised permit with a written statement from an independent third party documenting the repairs, replacement, or reconfiguration and certifying that the previous certification under § 250.731(c) remains valid. (4) You must receive approval from the District Manager prior to resuming operations.
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe;	Record the reason for postponing the test in the daily report and conduct the required BOP test after the first trip out of the hole.
(d) BOP control station or pod that does not function properly;	Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.
(e) Plan to operate with a tapered string;	Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;	Before running casing, perform a shell test to the permit approved test pressure of the BOP component above the casing ram/casing shear. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
(g) Plan to use an annular BOP with a RWP less than the anticipated surface pressure;	Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its RWP and obtain approval from the District Manager.
(h) Plan to use a subsea BOP system in an ice-scour area;	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate any shear ram and pipe or casing is sheared;	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from an independent third party certifying that the BOP is fit to return to service.
(j) Need to remove the BOP stack;	Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers and test(s).
(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind shear ram opening immediately upon re-establishing power to the BOP stack;	Place the blind shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.
(l) If a test ram is to be used;	The wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed. This can be done by: (1) Testing wellhead/BOP connection to the MASP plus 500 psi for the well upon installation; (2) Pressure testing each casing to the MASP plus 500 psi for the next hole section; or (3) Some combination of paragraphs (l)(1) and (2) of this section.
(m) Plan to utilize any other circulating or ancillary equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart;	Contact the District Manager and request approval in your APD or APM. Your request must include a report from an independent third party on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.

If you encounter the following situation:	Then you must . . .
(n) You have pipe/variable bore rams that have no current utility or well-control purposes;	Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.
(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines);	Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from an independent third party that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.
(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations.	Ensure that the well is stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21983, May 15, 2019]

§ 250.739 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in § 250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of BOP stack equipment beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.

(b) A major, detailed inspection of the well control system components (including but not limited to riser, BOP, LMRP, and control pods) must be performed every 5 years. This major inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. An independent third party is required to review the inspection results and must compile a detailed report of the inspection results, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This major inspection must be performed every 5 years from the following applicable dates, whichever is later:

(1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system;

(2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or

(3) The date of the last 5 year inspection for the component.

(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.

(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, are trained in accordance with applicable training requirements in subpart S of this part, any applicable OEM criteria, recognized engineering practices, and industry standards incorporated by reference in this subpart.

(e) You must make all records available to BSEE upon request. You must ensure that the rig unit owner maintains the BOP maintenance, inspection, and repair records on the rig unit for 2 years from the date the records are created or for a longer period if directed by BSEE. You must ensure that

all equipment schematics, maintenance, inspection, and repair records are located at an onshore location for the service life of the equipment.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21983, May 15, 2019]

RECORDS AND REPORTING

§ 250.740 What records must I keep?

You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following:

(a) Well operations, all testing conducted, and any real-time monitoring data as required by § 250.724;

(b) Descriptions of formations penetrated;

(c) Content and character of oil, gas, water, and other mineral deposits in each formation;

(d) Kind, weight, size, grade, and setting depth of casing;

(e) All well logs and surveys run in the wellbore;

(f) Any significant malfunction or problem; and

(g) All other information required by the District Manager as appropriate to ensure compliance with the requirements of this section and to enable BSEE to determine that the well operations are consistent with conservation of natural resources and protection of safety and the environment on the OCS.

§ 250.741 How long must I keep records?

You must keep records for the time periods shown in the following table.

You must keep records relating to . . .	Until . . .
(a) Drilling;	90 days after you complete operations.
(b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data;	2 years after the completion of operations.
(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.	You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.

§ 250.742 What well records am I required to submit?

You must submit to BSEE copies of logs or charts of electrical, radioactive, sonic, and other well logging operations; directional and vertical well surveys; velocity profiles and surveys; and analysis of cores. Each Region will provide specific instructions for submitting well logs and surveys.

§ 250.743 What are the well activity reporting requirements?

(a) For operations in the BSEE Gulf of Mexico (GOM) OCS Region, you must submit Form BSEE–0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE–0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.

(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE–0133, WAR, to the District Manager on a daily basis.

(c) The WAR must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day

within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information concerning well activities required by the District Manager. For casing cementing operations, indicate type of returns (*i.e.*, full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

§ 250.744 What are the end of operation reporting requirements?

(a) Within 30 days after completing operations, except routine operations as defined in § 250.601, you must submit Form BSEE–0125, End of Operations Report (EOR), to the District Manager. The EOR must include: a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager regarding the end of well operations. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The well status date is subject to the following:

(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and

(2) For subsea well operations, the operations end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.

(b) You must submit public information copies of Form BSEE–0125 according to § 250.186(b).

§ 250.745 What other well records could I be required to submit?

The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records:

(a) Well records as specified in § 250.740;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;

(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or

(d) Other reports and records of operations.

§ 250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in § 250.740. In addition, you must:

(a) Record test pressures on pressure charts or digital recorders;

(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts or digital recordings and daily reports as correct;

(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP

systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);

(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing must be documented in the WAR. If any problems that cannot be resolved promptly are observed during testing, operations must be suspended until the District Manager determines that you may continue; and

(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the rig unit for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the rig unit. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all the records available to BSEE upon request.

COILED TUBING OPERATIONS

§ 250.750 What are the coiled tubing requirements?

(a) For coiled tubing operations, you must follow the applicable requirements of this subpart and you must meet the following minimum requirements for the BOP system:

(1) BOP system components must be in the following order from the top down:

BOP system when expected surface pressures are less than or equal to 3,500 psi	BOP system when expected surface pressures are greater than 3,500 psi	BOP system for wells with returns taken through an outlet on the BOP stack
(i) Stripper or annular-type well control component.	Stripper or annular-type well control component.	Stripper or annular-type well control component.
(ii) Hydraulically-operated blind rams.	Hydraulically-operated blind rams	Hydraulically-operated blind rams.
(iii) Hydraulically-operated shear rams.	Hydraulically-operated shear rams	Hydraulically-operated shear rams.
(iv) Kill line inlet	Kill line inlet	Kill line inlet.
(v) Hydraulically-operated two-way slip rams.	Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams.
(vi) Hydraulically-operated pipe rams.	Hydraulically-operated pipe rams	Hydraulically-operated pipe rams.
		A flow tee or cross.
	Hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical.	Hydraulically-operated pipe rams.
		Hydraulically-operated blind-shear rams on wells with surface pressures >3,500 psi. As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be located as close to the tree as practical.

(2) You may use a set of hydraulically-operated combination rams for the blind rams and shear rams.

(3) You may use a set of hydraulically-operated combination rams for the hydraulic two-way slip rams and the hydraulically-operated pipe rams.

(4) You must attach a dual check valve assembly to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form BSEE–0124, Application for Permit to Modify and have it approved by the District Manager.

(5) You must have a kill line and a separate choke line. You must equip each line with two full-opening valves and at least one of the valves must be remotely controlled. You may use a manual valve instead of the remotely controlled valve on the kill line if you install a check valve between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which

they are attached, and you must install them between the well control stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or manifold. You must not use the kill line inlet on the BOP stack for taking fluid returns from the wellbore.

(6) You must have a hydraulic-actuating system that provides sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the precharge pressure, without assistance from a charging system.

(7) All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

(b) BSEE considers all coiled tubing operations to be non-routine.

[84 FR 21983, May 15, 2019]

§ 250.751 Coiled tubing testing requirements.

You must test the coiled tubing unit in accordance with § 250.737(a), (b), (c), (d)(9), and (d)(10). You must successfully pressure test the dual check valves to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less. The test interval for coiled tubing operations must include a 10 minute high-pressure test for the coiled tubing string.

[84 FR 21984, May 15, 2019]

SNUBBING OPERATIONS

§ 250.760 What are the snubbing requirements?

(a) For snubbing operations, you must follow the applicable requirements of this subpart and have the following minimum BOP-system components:

(1) One set of pipe rams hydraulically operated,

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool,

(3) An inside BOP or a spring-loaded, back-pressure safety valve in the open position located on the rig floor, and

(4) An essentially full-opening, workstring safety valve in the open position must be maintained on the rig floor at all times and a wrench to fit the workstring safety valve must be readily available.

(5) Proper connections must be readily available for inserting valves in the work string.

(b) Test the snubbing unit in accordance with § 250.737(a), (b), and (c).

[84 FR 21984, May 15, 2019]

Subpart H—Oil and Gas Production Safety Systems

SOURCE: 81 FR 60918, Sept. 7, 2016, unless otherwise noted.

GENERAL REQUIREMENTS

§ 250.800 General.

(a) You must design, install, use, maintain, and test production safety equipment in a manner to ensure the safety and protection of the human, marine, and coastal environments. For production safety systems operated in subfreezing climates, you must use equipment and procedures that account for floating ice, icing, and other extreme environmental conditions that may occur in the area. Before you commence production on a new production facility:

(1) BSEE must approve your production safety system application, as required in § 250.842.

(2) You must request a preproduction inspection by notifying the District Manager at least 72 hours before you plan to commence initial production, as required under § 250.880(a)(1).

(b) For all new production systems on fixed leg platforms, you must comply with API RP 14J (incorporated by reference as specified in § 250.198);

(c) For all new floating production systems (FPSs) (e.g., column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); and spars), you must:

(1) Comply with API RP 14J;

(2) Meet the production riser standards of API RP 2RD (incorporated by reference as specified in § 250.198), provided that you may not install single bore production risers from floating production facilities;

(3) Design all stationkeeping (*i.e.*, anchoring and mooring) systems for floating production facilities to meet the standards of API RP 2SK and API RP 2SM (both incorporated by reference as specified in § 250.198); and

(4) Design stationkeeping (*i.e.*, anchoring and mooring) systems for floating facilities to meet the structural requirements of §§ 250.900 through 250.921.

(d) If there are any conflicts between the documents incorporated by reference and the requirements of this subpart, you must follow the requirements of this subpart.

(e) You may use alternate procedures or equipment during operations after receiving approval from the District Manager. You must present your proposed alternate procedures or equipment as required by § 250.141.

(f) You may apply for a departure from the operating requirements of this subpart as provided by § 250.142. Your written request must include a justification showing why the departure is necessary and appropriate.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

§ 250.801 Safety and pollution prevention equipment (SPPE) certification.

(a) *SPPE equipment*. You must install only safety and pollution prevention equipment (SPPE) considered certified under paragraph (b) of this section or accepted under paragraph (c) of this section. BSEE considers the following equipment to be types of SPPE:

(1) Surface safety valves (SSV) and actuators, including those installed on injection wells capable of natural flow;

(2) Boarding shutdown valves (BSDV) and their actuators. For subsea wells, the BSDV is the surface equivalent of an SSV on a surface well;

(3) Underwater safety valves (USV) and actuators;

(4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples; and

(5) Gas lift shutdown valves (GLSDV) and their actuators associated with subsea systems.

(b) *Certification of SPPE*. SPPE that is manufactured and marked pursuant to ANSI/API Spec. Q1 (incorporated by reference as specified in § 250.198), is considered as certified SPPE under this part. All other SPPE is considered as not certified, unless approved in accordance with paragraph (c) of this section.

(c) *Accepting SPPE manufactured under other quality assurance programs*. BSEE may exercise its discretion to accept SPPE manufactured under a quality assurance program other than ANSI/API Spec. Q1, provided that the alternative quality assurance program is verified as equivalent to API Spec. Q1 by an appropriately qualified entity and that the operator submits a request to BSEE containing relevant information about the alternative program and receives BSEE approval. In addition, an operator may request that BSEE accept SPPE that is marked with a third-party certification mark other than the API monogram. All requests under this paragraph should be submitted to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; VAE–ORP; 45600 Woodland Road, Sterling, VA 20166.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

§ 250.802 Requirements for SPPE.

(a) All SSVs, BSDVs, USVs, and GLSDVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference in § 250.198).

(b) All SSSVs and their actuators must meet all of the specifications and recommended practices of ANSI/API Spec. 14A and ANSI/API RP 14B, including all annexes (both incorporated by reference as specified in § 250.198). Subsurface-controlled SSSVs are not allowed on subsea wells.

(c) Requirements derived from the documents incorporated in this section for SSVs, BSDVs, SSSVs, USVs, GLSDVs, and their actuators, include, but are not limited to, the following:

(1) You must ensure that each device is designed to function in the conditions to which it may be exposed; including temperature, pressure, flow rates, and environmental conditions.

(i) The device design must be tested by an independent test agency according to the test requirements in the appropriate standard for that device (API Spec. 6AV1 or ANSI/API Spec. 14A), as identified in paragraphs (a) and (b) of this section.

(ii) You must maintain a description of the process you used to ensure the device is designed to function as required in paragraphs (a) and (c)(1) of this section and provide that description to BSEE upon request.

(iii) If you remove any SPPE from service and install the device at a different location, you must have a qualified third party review and certify that each device will function as designed under the conditions to which it may be exposed.

(2) All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.

(3) The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.

(4) You must have requalification testing performed following manufacture design changes.

(5) You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.

(6) You must follow specified installation, testing, and repair protocols.

(7) You must use only qualified parts, procedures, and personnel to repair or redress equipment.

(d) You must install and use SPPE according to the following table.

If . . .	Then . . .
(1) You need to install any SPPE	You must install SPPE that conforms to § 250.801.
(2) A non-certified SPPE is already in service	It may remain in service.
(3) A non-certified SPPE requires offsite repair, re-manufacturing, or any hot work such as welding.	You must replace it with SPPE that conforms to § 250.801.

(e) You must retain all documentation related to the manufacture, installation, testing, repair, redress, and performance of the SPPE until 1 year after the date of decommissioning of the equipment.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

§ 250.803 What SPPE failure reporting procedures must I follow?

(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of ANSI/API Spec. 6A for SSVs, BSDVs, GLSDVs and USVs. You must follow the failure reporting requirements contained in section 7.10 of ANSI/API Spec. 14A and Annex F of ANSI/API RP 14B for SSSVs (all incorporated by reference in § 250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.

(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.

(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to

BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section.

(d) BSEE may designate a third party to receive the data required by paragraphs (a) through (c) of this section on behalf of BSEE. If BSEE designates a third party, you must submit the information required in this section to the designated third party, as directed by BSEE.

[83 FR 49256, Sept. 28, 2018]

§ 250.804 Additional requirements for subsurface safety valves (SSSVs) and related equipment installed in high pressure high temperature (HPHT) environments.

(a) If you plan to install SSSVs and related equipment in an HPHT environment, you must submit detailed information with your Application for Permit to Drill (APD) or Application for Permit to Modify (APM), and Deepwater Operations Plan (DWOP) that demonstrates the SSSVs and related equipment are capable of performing in the applicable HPHT environment. Your detailed information must include the following:

(1) A discussion of the SSSVs' and related equipment's design verification analyses;

(2) A discussion of the SSSVs' and related equipment's design validation and functional testing processes and procedures used; and

(3) An explanation of why the analyses, processes, and procedures ensure that the SSSVs and related equipment are fit-for-service in the applicable HPHT environment.

(b) For this section, HPHT environment means when one or more of the following well conditions exist:

(1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psia or a temperature rating greater than 350 degrees Fahrenheit;

(2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psia on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or

(3) The flowing temperature is equal to or greater than 350 degrees Fahrenheit on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

(c) For this section, related equipment includes wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment.

§ 250.805 Hydrogen sulfide.

(a) In zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.490, you must conduct production operations in accordance with that section and other relevant requirements of this subpart.

(b) You must receive approval through the DWOP process (§§ 250.286 through 250.295) for production operations in HPHT environments known to contain H_2S or in HPHT environments where the presence of H_2S is unknown.

§§ 250.806–250.809 [Reserved]2

SURFACE AND SUBSURFACE SAFETY SYSTEMS—DRY TREES

§ 250.810 Dry tree subsurface safety devices—general.

For wells using dry trees or for which you intend to install dry trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after you submit a request containing a justification, the District Manager determines the well to be incapable of natural flow. You must install flow couplings above and below the subsurface safety devices. These subsurface safety devices include the following devices and any associated safety valve lock and landing nipple:

(a) An SSSV, including either:

(1) A surface-controlled SSSV; or

(2) A subsurface-controlled SSSV.

(b) An injection valve.

(c) A tubing plug.

(d) A tubing/annular subsurface safety device.

§ 250.811 Specifications for SSSVs—dry trees.

All surface-controlled and subsurface-controlled SSSVs, safety valve locks, and landing nipples installed in the OCS must conform to the requirements specified in §§ 250.801 through 250.803.

§ 250.812 Surface-controlled SSSVs—dry trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§ 250.813, 250.815, and 250.816.

(a) The surface controls must be located on the site or at a BSEE-approved remote location. You may request District Manager approval to situate the surface controls at a remote location.

(b) You must equip dry tree wells not previously equipped with a surface-controlled SSSV, and dry tree wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV, with a surface-controlled SSSV when the tubing is first removed and reinstalled.

§ 250.813 Subsurface-controlled SSSVs.

You may submit an APM or a request to the District Manager for approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, if the subsurface-controlled SSSV is installed in a well equipped with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing. If you remove and reinstall the tubing, you must equip the well with a surface-controlled SSSV.

§ 250.814 Design, installation, and operation of SSSVs—dry trees.

You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while the SSSV is inoperable, except when flowing the well is necessary for a particular operation such as cutting paraffin or performing other routine operations as defined in § 250.601.

(c) Until the SSSV is installed, the well must be attended in the immediate vicinity so that any necessary emergency actions can be taken while the well is open to flow. During testing and inspection procedures, the well must not be left unattended while open to production unless you have installed a properly operating SSSV in the well.

(d) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with ANSI/API RP 14B (incorporated by reference in § 250.198). For additional SSSV testing requirements, refer to § 250.880.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 250.815 Subsurface safety devices in shut-in wells—dry trees.

(a) You must equip all new dry tree completions (perforated but not placed on production) and completions that are shut-in for a period of 6 months with one of the following:

(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.

(b) When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

§ 250.816 Subsurface safety devices in injection wells—dry trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

§ 250.817 Temporary removal of subsurface safety devices for routine operations.

(a) You may remove a wireline- or pumpdown-retrievable subsurface safety device without further authorization or notice, for a routine operation that does not require BSEE approval of a Form BSEE–0124, Application for Permit to Modify (APM). For a list of these routine operations, see § 250.601. The removal period must not exceed 15 days.

(b) Prior to removal, you must identify the well by placing a sign on the wellhead stating that the subsurface safety device was removed. You must note the removal of the subsurface safety device in the records required by § 250.890. If the master valve is open, you must ensure that a trained person (see § 250.891) is in the immediate vicinity to attend the well and take any necessary emergency actions.

(c) You must monitor a platform well when a subsurface safety device has been removed, but a person does not need to 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 by a support vessel, or a pump-through plug must be installed in the tubing at least 100 feet below the mudline and the master valve must be closed, unless otherwise approved by the appropriate District Manager.

(d) You must not allow the well to flow while the subsurface safety device is removed, except when it is necessary for the particular operation for which the SSSV is removed. The provisions of this paragraph are not applicable to the testing and inspection procedures specified in § 250.880.

§ 250.818 Additional safety equipment—dry trees.

(a) You must equip all tubing installations that have a wireline- or pumpdown-retrievable subsurface safety device with a landing nipple, with flow couplings or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform emergency shutdown system (ESD).

(c) 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 SSSVs must close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

§ 250.819 Specification for surface safety valves (SSVs).

All wellhead SSVs and their actuators must conform to the requirements specified in §§ 250.801 through 250.803.

§ 250.820 Use of SSVs.

You must install, maintain, inspect, repair, and test all SSVs in accordance with API STD 6AV2 (incorporated by reference in § 250.198). If any SSV does not operate properly, or if any gas and/or liquid fluid flow is observed during the leakage test as described in § 250.880, then you must shut-in all sources to the SSV and repair or replace the valve before resuming production.

[83 FR 49257, Sept. 28, 2018]

§ 250.821 Emergency action and safety system shutdown—dry trees.

(a) If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.*, an impending National Weather Service-named tropical storm or hurricane, ice events, or post-earthquake), you must:

(1) Properly install a subsurface safety device on any well that is not yet equipped with a subsurface safety device and that is capable of natural flow, as soon as possible, with due consideration being given to personnel safety.

(2) You must shut-in (by closing the SSV and the surface-controlled SSSV) the following types of wells:

(i) All oil wells, and

(ii) All gas wells requiring compression.

(b) Closure of the SSV must not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV must close within 2 minutes after the shut-in signal has closed the SSV. The District Manager must approve any alternative design-delayed

closure time of greater than 2 minutes based on the mechanical/production characteristics of the individual well.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§§ 250.822–250.824 [Reserved]

SUBSEA AND SUBSURFACE SAFETY SYSTEMS—SUBSEA TREES

§ 250.825 Subsea tree subsurface safety devices—general.

(a) For wells using subsea (wet) trees or for which you intend to install subsea trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency. You must also install flow couplings above and below the subsurface safety devices. For instances where the well at issue is incapable of natural flow, you may seek District Manager approval for using alternative procedures or equipment, if you propose to use a subsea safety system that is not capable of shutting off the flow from the well in the event of an emergency. Subsurface safety devices include the following and any associated safety valve lock and landing nipple:

(1) A surface-controlled SSSV;

(2) An injection valve;

(3) A tubing plug; and

(4) A tubing/annular subsurface safety device.

(b) After installing the subsea tree, but before the rig or installation vessel leaves the area, you must test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in this subpart.

§ 250.826 Specifications for SSSVs—subsea trees.

All SSSVs, safety valve locks, and landing nipples installed on the OCS must conform to the requirements specified in §§ 250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §§ 250.286 through 250.295.

§ 250.827 Surface-controlled SSSVs—subsea trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§ 250.829 and 250.830. The surface controls must be located on the host facility.

§ 250.828 Design, installation, and operation of SSSVs—subsea trees.

You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline. When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while an SSSV is inoperable, unless specifically approved by the District Manager in an APM.

(c) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and ANSI/API RP 14B (incorporated by reference in § 250.198). For additional SSSV testing requirements, refer to § 250.880.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 250.829 Subsurface safety devices in shut-in wells—subsea trees.

(a) You must equip all new subsea tree completions (perforated but not placed on production) and completions shut-in for a period of 6 months with one of the following:

(1) A pump-through-type tubing plug;

(2) An injection valve capable of preventing backflow; or

(3) A surface-controlled SSSV, provided the surface control has been rendered inoperative. For purposes of this section, a surface-controlled SSSV is considered inoperative if, for a direct hydraulic control system, you have bled the hydraulics from the control line and have isolated it from the hydraulic control pressure. If your controls employ an electro-hydraulic control umbilical and the hydraulic control pressure to the individual well cannot be isolated, a surface-controlled

SSSV is considered inoperative if you perform the following:

(i) Disable the control function of the surface-controlled SSSV within the logic of the programmable logic controller which controls the subsea well;

(ii) Place a pressure alarm high on the control line to the surface-controlled SSSV of the subsea well; and

(iii) Close the USV and at least one other tree valve on the subsea well.

(b) When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

§ 250.830 Subsurface safety devices in injection wells—subsea trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

§ 250.831 Alteration or disconnection of subsea pipeline or umbilical.

If a necessary alteration or disconnection of the pipeline or umbilical of any subsea well would affect your ability to monitor casing pressure or to test any subsea valves or equipment, you must contact the appropriate District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing. You must not alter or disconnect until the repair or replacement plan is approved.

§ 250.832 Additional safety equipment—subsea trees.

(a) You must equip all tubing installations that have a wireline- or pump down-retrievable subsurface safety device installed after May 31, 1988, with a landing nipple, with flow couplings, or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform ESD.

(c) 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.

§ 250.833 Specification for underwater safety valves (USVs).

All USVs, including those designated as primary or secondary, and any alternate isolation valve (AIV) that acts as a USV, if applicable, and their actuators, must conform to the requirements specified in §§ 250.801 through 250.803. A production master or wing valve may qualify as a USV under ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference in § 250.198).

(a) Primary USV (USV1). You must install and designate one USV on a subsea tree as the USV1. The USV1 must be located upstream of the choke valve. As provided in paragraph (b) of this section, you must inform BSEE if the primary USV designation changes.

(b) Secondary USV (USV2). You may equip your tree with two or more valves qualified to be designated as a USV, one of which may be designated as the USV2. If the USV1 fails to operate properly or exhibits a leakage rate greater than allowed in § 250.880, you must notify the appropriate District Office and designate the USV2 or another qualified valve (e.g., an AIV) that meets all the requirements of this subpart for USVs as the USV1. The USV2 must be located upstream of the choke.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 250.834 Use of USVs.

You must install, maintain, inspect, repair, and test any valve designated as the primary USV in accordance with this subpart, your DWOP (as specified in §§ 250.286 through 250.295), and API STD 6AV2 (incorporated by reference in § 250.198). For additional USV testing requirements, refer to § 250.880.

[83 FR 49257, Sept. 28, 2018]

§ 250.835 Specification for all boarding shutdown valves (BSDVs) associated with subsea systems.

You must install a BSDV on the pipeline boarding riser. All new BSDVs and any BSDVs removed from service for

remanufacturing or repair and their actuators installed on the OCS must meet the requirements specified in §§ 250.801 through 250.803. In addition, you must:

(a) Ensure that the internal design pressure(s) of the pipeline(s), riser(s), and BSDV(s) is fully rated for the maximum pressure of any input source and complies with the design requirements set forth in subpart J, unless BSEE approves an alternate design.

(b) Use a BSDV that is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application.

(c) Locate the BSDV within 10 feet of the first point of access to the boarding pipeline riser (*i.e.*, within 10 feet of the edge of platform if the BSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical).

(d) Install a temperature safety element (TSE) and locate it within 5 feet of each BSDV.

§ 250.836 Use of BSDVs.

You must install, inspect, maintain, repair, and test all new BSDVs, as well as all BSDVs that you remove from service for remanufacturing or repair, in accordance with API STD 6AV2 (incorporated by reference in § 250.198) for SSVs. If any BSDV does not operate properly or if any gas fluid and/or liquid fluid flow is observed during the leakage test, as described in § 250.880, you must shut-in all sources to the BSDV and immediately repair or replace the valve.

[83 FR 49257, Sept. 28, 2018]

§ 250.837 Emergency action and safety system shutdown—subsea trees.

(a) If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.*, an impending National Weather Service-named tropical storm or hurricane, ice events, or post-earthquake), you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, GLSDV, and surface-controlled SSSV.

(b) When operating a mobile offshore drilling unit (MODU) or other type of workover or intervention vessel in an area with subsea infrastructure, you must:

(1) Suspend production from all wells that could be affected by a dropped object, including upstream wells that flow through the same pipeline; or

(2) Establish direct, real-time communications between the MODU or other type of workover or intervention vessel and the production facility control room and develop a dropped objects plan, as required in § 250.714. If an object is dropped, you must immediately secure the well directly under the MODU or other type of workover or intervention vessel while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the production facility and the MODU or other type of workover or intervention vessel. If communication is lost between the MODU or other type of workover or intervention vessel and the platform for 20 or more minutes, you must shut-in all wells that could be affected by a dropped object.

(c) In the event of an emergency, you must operate your production system according to the valve closure times in the applicable tables in §§ 250.838 and 250.839 for the following conditions:

(1) *Process upset*. In the event an upset in the production process train occurs downstream of the BSDV, you must close the BSDV in accordance with the applicable tables in §§ 250.838 and 250.839. You may reopen the BSDV to blow down the pipeline to prevent hydrates, provided you have secured the well(s) and ensured adequate protection.

(2) *Pipeline pressure safety high and low (PSHL) sensor*. In the event that either a high or a low pressure condition is detected by a PSHL sensor located upstream of the BSDV, you must secure the affected well and pipeline, and all wells and pipelines associated with a dual or multi pipeline system, by closing the BSDVs, USVs, and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must obtain approval from the appropriate District Manager to resume production in the unaffected

pipeline(s) of a dual or multi pipeline system. If the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate District Manager.

(3) *ESD/TSE (platform)*. In the event of an ESD activation that is initiated because of a platform ESD or platform TSE not associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§ 250.838 and 250.839.

(4) *Subsea ESD (platform) or BSDV TSE*. In the event of an emergency shutdown activation that is initiated by the host platform due to an abnormal condition subsea, or a TSE associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§ 250.838 and 250.839.

(5) *Subsea ESD (MODU)*. In the event of an ESD activation that is initiated by a dropped object from a MODU or other type of workover or intervention vessel, you must secure all wells in the proximity of the MODU or other type of workover or intervention vessel by closing the USVs and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must notify the appropriate District Manager before resuming production.

(d) Following an ESD or fire, you must bleed your low pressure (LP) and high pressure (HP) hydraulic systems in accordance with the applicable tables in §§ 250.838 and 250.839 to ensure that the valves are locked out of service and cannot be reopened inadvertently.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?

(a) If you have an electro-hydraulic control system, you must:

(1) Design the subsea control system to meet the valve closure times listed in paragraphs (b) and (d) of this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP as long as communication is maintained with the platform or with the MODU or other type of workover vessel:

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements].	[no requirements].	[no requirements].
(2) Pipeline PSHL.	Close within 45 seconds after sensor activation.	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation.			Close within 60 minutes after sensor activation. If you use a 60-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 24 hours total.	[no requirements].	Initiate unrestricted bleed within 24 hours after sensor activation.

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM—Continued

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Close within 5 minutes after ESD or sensor activation. If you use a 5-minute resettable timer, you may continue to reset the time for closure up to a maximum of 20 minutes total.	Close within 20 minutes after ESD or sensor activation.		Close within 20 minutes after ESD or sensor activation. If you use a 20-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 60 minutes total.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute manual resettable timer you must initiate unrestricted bleed within 24 hours.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute manual resettable timer you must initiate unrestricted bleed within 24 hours.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation			Close within 10 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(5) Subsea ESD (MODU or other type of workover vessel, Dropped object).	[no requirements].	Initiate valve closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed within 10 minutes after ESD activation.

(c) If you have an electro-hydraulic control system and experience a loss of communications (EH Loss of Comms), you must comply with the following:

(1) If you can meet the EH Loss of Comms valve closure timing conditions specified in the table in paragraph (d) of this section, you must notify the appropriate District Office within 12 hours of detecting the loss of communication.

(2) If you cannot meet the EH Loss of Comms valve closure timing conditions specified in the table in paragraph (d) of this section, you must notify the appropriate District Office immediately after detecting the loss of communication. You must shut-in production by initiating a bleed of the low pressure (LP) hydraulic system or the high pressure (HP) hydraulic system within 120 minutes after loss of communication. You must bleed the other hydraulic system within 180 minutes after loss of communication.

(3) You must obtain approval from the appropriate District Manager before continuing to produce after loss of communication when you cannot meet the EH Loss of Comms valve closure times specified in the table in paragraph (d) of this section. In your request, include an alternate valve closure timing table that your system is able to achieve. The appropriate District Manager may also approve an alternate hydraulic bleed schedule to allow for hydrate mitigation and orderly shut-in.

(d) If you experience a loss of communications, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, ELECTRO-HYDRAULIC CONTROL SYSTEM WITH LOSS OF COMMUNICATION

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements].	[no requirements].	[no requirements].
(2) Pipeline PSHL.	Close within 45 seconds after sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after sensor activation).			Initiate closure when HP hydraulic system is bled (close within 24 hours after sensor activation).	Initiate unrestricted bleed immediately, concurrent with sensor activation.	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 20 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 60 minutes after ESD or sensor activation).	Initiate unrestricted bleed concurrent with BSDV closure (bleed within 20 minutes after ESD or sensor activation).	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 20 minutes after ESD or sensor activation).	Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately, allowing for surface-controlled SSSV closure.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object.	[no requirements].	Initiate closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

§ 250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system?

(a) If you have a direct-hydraulic control system, you must:

(1) Design the subsea control system to meet the valve closure times listed in this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

VALVE CLOSURE TIMING, DIRECT-HYDRAULIC CONTROL SYSTEM

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset.	Close within 45 seconds after sensor activation.	[no requirements]			[no requirements].	[no requirements].	[no requirements]
(2) Flowline PSHL.	Close within 45 seconds after sensor activation.	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation.			Close within 24 hours after sensor activation.	Complete bleed of USV1, USV2, and the AIV within 20 minutes after sensor activation.	Complete bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform).	Close within 45 seconds after ESD or sensor activation.	Close all valves within 20 minutes after ESD or sensor activation.			Close within 60 minutes after ESD or sensor activation.	Complete bleed of USV1, USV2, and the AIV within 20 minutes after ESD or sensor activation.	Complete bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE.	Close within 45 seconds after ESD or sensor activation.	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation.			Close within 10 minutes after ESD or sensor activation.	Complete bleed of USV1, USV2, and the AIV within 10 minutes after ESD or sensor activation.	Complete bleed within 10 minutes after ESD or sensor activation.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object.	[no requirements].	Initiate closure immediately. If desired, you may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV.				Initiate unrestricted bleed immediately.	Initiate unrestricted bleed immediately.

PRODUCTION SAFETY SYSTEMS

§ 250.840 Design, installation, and maintenance—general.

You must design, install, and maintain all production facilities and equipment including, but not limited to, separators, treaters, pumps, heat exchangers, fired components, wellhead injection lines, compressors, headers, and flowlines in a manner that is efficient, safe, and protects the environment.

§ 250.841 Platforms.

(a) You must protect all platform production facilities 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 (incorporated by reference as specified in § 250.198). If you use processing components other than those for which Safety Analysis Checklists are included in API RP 14C, you must utilize the analysis technique and documentation specified in API RP 14C to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are contained in § 250.1004.

(b) You must design, install, inspect, repair, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E and API 570 (both incorporated by

reference as specified in § 250.198). The District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.

(c) If you plan to make a modification to any production safety system that also involves a major modification to the platform structure, you must follow the requirements in § 250.900(b)(2). A major modification to a platform structure is defined in § 250.900(b)(2).

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

§ 250.842 Approval of safety systems design and installation features.

(a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager. The District Manager must approve your production safety system application before you commence production through or otherwise use the new or modified system. The application must include the design documentation prescribed as follows:

You must submit:	Details and/or additional requirements:
(1) Safety analysis flow diagram (API RP 14C, Annex B) and Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, section 6.3.3) (incorporated by reference in § 250.198)	Your safety analysis flow diagram must show the following: (i) Well shut-in tubing pressure; (ii) Pressure relieving device set points; (iii) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors, and metering devices; (iv) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps; (v) Size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and API RP 505 (both incorporated by reference in § 250.198); and (vi) Piping sizes and maximum allowable working pressures as determined in accordance with API RP 14E (incorporated by reference in § 250.198), including the locations of piping specification breaks.
(2) Electrical one-line diagram;	Showing elements including generators, circuit breakers, transformers, bus bars, conductors, automatic transfer switches, uninterruptable power supply (UPS) and associated battery banks, dynamic (motor) loads, and static loads (*e.g.,* electrostatic treater grid, lighting panels). You must also include a functional legend.
(3) Area classification diagram;	A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500 or API RP 505 (both incorporated by reference in § 250.198). The plan must contain: (i) All major production equipment, wells, and other significant hydrocarbon and class 1 flammable sources, and a description of the type of decking, ceiling, walls (e.g., grating or solid), and firewalls; and (ii) The location of generators and any buildings (e.g., control rooms and motor control center (MCC) buildings) or major structures on the platform.
(4) A piping and instrumentation diagram, for new facilities;	A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.
(5) The service fee listed in § 250.125;	The fee you must pay will be determined by the number of components involved in the review and approval process.

(b) You must develop and maintain the following design documents and make them available to BSEE upon request:

Diagram:	Details and/or additional requirements:
(1) Additional electrical system information;	(i) Cable tray/conduit routing plan that identifies the primary wiring method (e.g., type cable, cable schedule, conduit, wire); and (ii) Panel board/junction box location plan, if this information is not shown on the area classification diagram required in paragraph (a)(3) of this section.
(2) Schematics of the fire and gas-detection systems;	Showing a functional block diagram of the detection system, including the electrical power supply and also including the type, location, and number of detection sensors; the type and kind of alarms, including emergency equipment to be activated; and the method used for detection.
(3) Revised piping and instrumentation diagram for existing facilities;	A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.

(c) In the production safety system application, you must also certify the following:

(1) That all electrical systems were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference in § 250.198);

(2) That the design documents for the mechanical and electrical systems that you are required to submit under paragraph (a) of this section are sealed by a licensed professional engineer. For modified systems, only the modifications are required to be sealed by a licensed professional engineer(s). The professional engineer must be licensed in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and

(3) That a hazards analysis was performed in accordance with § 250.1911 and API RP 14J (incorporated by reference in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the facility.

(d) Within 90 days after placing new or modified production safety systems in service, you must submit to the District Manager the as-built diagrams for the new or modified production safety systems outlined in paragraphs (a)(1), (2), and (3) of this section. You must certify in an accompanying letter that the as-built design documents have been reviewed for compliance with applicable regulations and accurately represent the new or modified system as installed. The drawings must be clearly marked ''as-built.''

(e) You must maintain approved and supporting design documents required under paragraphs (a) and (b) of this section at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. These documents must be made available to BSEE upon request and must be retained for the life of the facility. All approved designs are subject to field verifications.

[84 FR 24705, May 29, 2019]

§§ 250.843–250.849 [Reserved]

ADDITIONAL PRODUCTION SYSTEM REQUIREMENTS

§ 250.850 Production system requirements—general.

You must comply with the production safety system requirements in §§ 250.851 through 250.872, in addition to the practices contained in API RP 14C (incorporated by reference as specified in § 250.198).

§ 250.851 Pressure vessels (including heat exchangers) and fired vessels.

(a) Pressure vessels (including heat exchangers) and fired vessels supporting production operations must meet the requirements in the following table:

Item name	Applicable codes and requirements
(1) Pressure and fired vessels	(i) Must be designed, fabricated, and code stamped according to applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in § 250.198). (ii) Must be repaired, maintained, and inspected in accordance with API 510 (incorporated by reference as specified in § 250.198).
(2) Existing uncoded pressure and fired vessels: (i) With an operating pressure greater than 15 psig; and (ii) That are not code stamped in accordance with the ASME Boiler and Pressure Vessel Code.	Must be justified and approval obtained from the District Manager for their continued use.

Item name	Applicable codes and requirements
(3) Pressure relief valves	(i) Must be designed and installed according to applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in § 250.198). (ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but must be set no higher than the maximum-allowable working pressure of the vessel (except for cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only). (iii) Vents must be positioned in such a way as to prevent fluid from striking personnel or ignition sources.
(4) Steam generators operating at less than 15 psig	Must 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.
(5) Steam generators operating at 15 psig or greater	(i) Must 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. (ii) Must be equipped with a water-feeding device that will automatically control the water level except when closed loop systems are used for steam generation.

(b) *Operating pressure ranges.* You must use pressure recording devices to establish the new operating pressure ranges of pressure vessels at any time that the normalized system pressure changes by 50 psig or 5 percent. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must maintain the pressure recording information you used to determine current operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) High pressure shut-in sensor,.	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the vessel.	Must 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.
(2) Low pressure shut-in sensor,.	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest pressure in the operating range.	You must receive specific approval from the District Manager for activation limits on pressure vessels that have a pressure safety low (PSL) sensor set less than 5 psi.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 24706, May 29, 2019]

§ 250.852 Flowlines/Headers.

(a) You must:

(1) Equip flowlines from wells with both PSH and PSL sensors. You must locate these sensors in accordance with section A.1 of API RP 14C (incorporated by reference as specified in § 250.198).

(2) Use pressure recording devices to establish the new operating pressure ranges of flowlines at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long.

(3) Maintain the most recent pressure recording information you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(b) Flowline shut-in sensors must meet the requirements in the following table (initial set points for pressure sensors must be set using gauge readings and engineering design):

Type of flowline sensor	Settings
(1) PSH sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the flowline. In all cases, the PSH must be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to ensure actuation of the SSV. Do not set the PSH sensor above the maximum allowable working pressure of the flowline.
(2) PSL sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the flowline in which it is installed.

(c) If a well flows directly to a pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) must 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:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. You must design the platform flare scrubber to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of hydrocarbons that may be relieved to the vessel; or

(2) Two SSVs with independent PSH sensors connected to separate relays and sensing points and installed with adequate volume upstream of any block valve to allow sufficient time for the SSVs to close before exceeding the maximum allowable working pressure. Each independent PSH sensor must close both SSVs along with any associated flowline PSL sensor. If the maximum shut-in pressure of a dry tree satellite well(s) is greater than 1½ times the maximum allowable pressure of the pipeline, a pressure safety valve (PSV) of sufficient size and relief capacity to protect against any SSV leakage or fluid hammer effect may be required by the District Manager. The PSV must be installed upstream of the host platform boarding valve and vent into the platform flare scrubber or some other location approved by the District Manager.

(d) If a well flows directly to the pipeline from a header without prior separation, the header, the header inlet valves, and pipeline isolation valve must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the header is protected by the safety devices as outlined in paragraph (c) of this section.

(e) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(1) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of ANSI/API Spec. 17J (incorporated by reference in § 250.198);

(2) Determine that the unbonded flexible pipe is suitable for its intended purpose;

(3) Submit to the District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(4) Submit to the District Manager a statement certifying that the pipe is suitable for its intended use and that the manufacturer has complied with the IVA requirements of ANSI/API Spec. 17J (incorporated by reference in § 250.198).

(f) Automatic pressure or flow regulating choking devices must not prevent the normal functionality of the process safety system that includes, but is not limited to, the flowline pressure safety devices and the SSV.

(g) You may install a single flow safety valve (FSV) on the platform to protect multiple subsea pipelines or wells that tie into a single pipeline riser provided that you install an FSV for each riser on the platform and test it in accordance with the criteria prescribed in § 250.880(c)(2)(v).

(h) You may install a single PSHL sensor on the platform to protect multiple subsea pipelines that tie into a single pipeline riser provided that you install a PSHL sensor for each riser on the platform and locate it upstream of the BSDV.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 250.853 Safety sensors.

You must ensure that:

(a) All shutdown devices, valves, and pressure sensors function in a manual reset mode;

(b) Sensors with integral automatic reset are equipped with an appropriate device to override the automatic reset mode;

(c) All pressure sensors are equipped to permit testing with an external pressure source; and

(d) All level sensors are equipped to permit testing through an external bridle on all new vessel installations where possible, depending on the type of vessel for which the level sensor is used.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 250.854 Floating production units equipped with turrets and turret-mounted systems.

(a) For floating production units equipped with an auto slew system, you must integrate the auto slew control system with your process safety system allowing for automatic shut-in of the production process, including the sources (subsea wells, subsea pumps, *etc.*) and releasing of the buoy. Your safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839 and release the buoy to prevent hydrocarbon discharge and damage to the subsea infrastructure when the following are encountered:

(1) Your buoy is clamped,

(2) Your auto slew mode is activated, and

(3) You encounter a ship heading/position failure or an exceedance of the rotational tolerances of the clamped buoy.

(b) For floating production units equipped with swivel stack arrangements, you must equip the portion of the swivel stack containing hydrocarbons with a leak detection system. Your leak detection system must be tied into your production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak, your surface safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839.

§ 250.855 Emergency shutdown (ESD) system.

The ESD system must conform to the requirements of Appendix C, section C1, of API RP 14C (incorporated by reference as specified in § 250.198), and the following:

(a) The manually operated ESD valve(s) must be quick-opening and non-restricted to enable the rapid actuation of the shutdown system. Electronic ESD stations must be wired as de-energize to trip circuits or as supervised circuits. Because of the key role of the ESD system in the platform safety system, all ESD components must be of high quality and corrosion resistant and stations must be uniquely identified. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve or electric switch. This breakable loop is not required to be physically located on the boat landing, but must be accessible from a vessel adjacent to or attached to the facility.

(b) You must maintain a schematic of the ESD that indicates the control functions of all safety devices for the platforms on the platform, at your field office nearest the OCS facility, or

at another location conveniently available to the District Manager, for the life of the facility.

§ 250.856 Engines.

(a) *Engine exhaust.* You must equip all engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2 (incorporated by reference as specified in § 250.198). You must equip exhaust piping from diesel engines with spark arresters.

(b) *Diesel engine air intake.* You must equip diesel engine air intakes with a device to shut down the diesel engine in the event of runaway (*i.e.*, overspeed). You must equip diesel engines that are continuously attended with either remotely operated manual or automatic shutdown devices. You must equip diesel engines that are not continuously attended with automatic shutdown devices. The following diesel engines do not require a shutdown device: Engines for fire water pumps; engines on emergency generators; engines that power BOP accumulator systems; engines that power air supply for confined entry personnel; temporary equipment on non-producing platforms; booster engines whose purpose is to start larger engines; and engines that power portable single cylinder rig washers.

§ 250.857 Glycol dehydration units.

(a) You must install a pressure relief system or an adequate vent on the glycol regenerator (reboiler) to prevent over pressurization. The discharge of the relief valve must be vented in a nonhazardous manner.

(b) You must install the FSV on the dry glycol inlet to the glycol contact tower as near as practical to the glycol contact tower.

(c) You must install the shutdown valve (SDV) on the wet glycol outlet from the glycol contact tower as near as practical to the glycol contact tower.

§ 250.858 Gas compressors.

(a) You must equip compressor installations with the following protective equipment as required in API RP 14C, sections A.4 and A.8 (incorporated by reference as specified in § 250.198).

(1) A pressure safety high (PSH) sensor, a pressure safety low (PSL) sensor, a pressure safety valve (PSV), a level safety high (LSH) sensor, and a level safety low (LSL) sensor to protect each interstage and suction scrubber.

(2) A temperature safety high (TSH) sensor in the discharge piping of each compressor cylinder or case discharge.

(3) You must design the PSH and PSL sensors and LSH controls protecting compressor suction and interstage scrubbers to actuate automatic SDVs 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 SDVs installed in compressor suction and fuel gas piping must also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Manager, gas-well gas affected by the closure of the automatic SDV on the suction side of a compressor must be diverted to the pipeline, diverted to a flare or vent in accordance with §§ 250.1160 or 250.1161, or shut-in at the wellhead.

(4) You must install a blowdown valve on the discharge line of all compressor installations that are 1,000 horsepower (746 kilowatts) or greater.

(b) Once system pressure has stabilized, you must use pressure recording devices to establish the new operating pressure ranges for compressor discharge sensors whenever the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line and sufficiently below the maximum discharge pressure to ensure actuation of the suction SDV.	Must also be set sufficiently below (5 percent or 5 psi, whichever is greater) the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.
(2) PSL sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the discharge line in which it is installed.	

§ 250.859 Firefighting systems.

(a) On fixed facilities, to protect all areas where production-handling equipment is located, you must install firefighting systems that meet the requirements of this paragraph. You must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors to protect all areas where production-handling equipment is located. Your firewater system must include installation of a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(1) Your firewater system must conform to API RP 14G (incorporated by reference as specified in § 250.198).

(2) Fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. If necessary, you must install an alternate fuel or power supply to provide for this pump operating time unless the District Manager has approved an alternate firefighting system. In addition:

(i) As of September 7, 2017, you must have equipped all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system.

(ii) For electric-driven firewater pump drivers, to provide for a potential loss of primary power, you must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source must be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment.

(iii) You must route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers must be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement.

(3) You must post, in a prominent place on the facility, a diagram of the firefighting system showing the location of all firefighting equipment.

(4) For operations in subfreezing climates, you must furnish evidence to the District Manager that the firefighting system is suitable for those conditions.

(5) You must obtain approval from the District Manager before installing any firefighting system.

(6) All firefighting equipment located on a facility must be in good working order whether approved as the primary, secondary, or ancillary firefighting system.

(b) On floating facilities, to protect all areas where production-handling equipment is located, you must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. Your firewater system must conform to the USCG requirements for firefighting systems on floating facilities.

(c) Except as provided in paragraph (c)(1) and (2) of this section, on fixed and floating facilities, if you are required to maintain a firewater system and the system becomes inoperable, you must shut-in your production operations while making the necessary repairs. For fixed facilities only, you may continue your production operations on a temporary basis while you

make the necessary repairs, provided that:

(1) You request that the appropriate District Manager approve the use of a chemical firefighting system on a temporary basis (for a period up to 7 days) while you make the necessary repairs;

(2) If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the District Manager may grant multiple extensions to your previously approved request to use a chemical firefighting system for periods up to 7 days each.

§ 250.860 Chemical firefighting system.

For fixed platforms:

(a) On minor unmanned platforms, you may use a U.S. Coast Guard type and size rating ''B–II'' portable dry chemical unit (with a minimum UL Rating (US) of 60–B:C) or a 30-pound portable dry chemical unit, in lieu of a water system, as long as you ensure that the unit is available on the platform when personnel are on board.

(1) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(2) An unmanned platform is one that is not attended 24 hours a day or one on which personnel are not quartered overnight.

(b) On major platforms and minor manned platforms, you may use a firefighting system using chemicals-only in lieu of a water-based system if the District Manager determines that the use of a chemical system provides equivalent fire-protection control and would not increase the risk to human safety.

(1) A major platform is a structure with either six or more completions or zero to five completions with more than one item of production processing equipment.

(2) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(3) A manned platform is one that is attended 24 hours a day or one on which personnel are quartered overnight.

(c) On major platforms and minor manned platforms, to obtain approval to use a chemical-only fire prevention and control system in lieu of a water system under paragraph (b) of this section, you must submit to the District Manager:

(1) A justification for asserting that the use of a chemical system provides equivalent fire-protection control. The justification must address fire prevention, fire protection, fire control, and firefighting on the platform; and

(2) A risk assessment demonstrating that a chemical-only system would not increase the risk to human safety. You must provide the following and any other important information in your risk assessment:

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
(i) Platform description	(A) The type and quantity of hydrocarbons (*i.e.,* natural gas, oil) that are produced, handled, stored, or processed at the facility.
	(B) The capacity of any tanks on the facility that you use to store either liquid hydrocarbons or other flammable liquids.
	(C) The total volume of flammable liquids (other than produced hydrocarbons) stored on the facility in containers other than bulk storage tanks. Include flammable liquids stored in paint lockers, storerooms, and drums.
	(D) If the facility is manned, provide the maximum number of personnel on board and the anticipated length of their stay.
	(E) If the facility is unmanned, provide the number of days per week the facility will be visited, the average length of time spent on the facility per visit, the mode of transportation, and whether or not transportation will be available at the facility while personnel are on board.
	(F) A diagram that depicts: quarters location, production equipment location, fire prevention and control equipment location, lifesaving appliances and equipment location, and evacuation plan escape routes from quarters and all manned working spaces to primary evacuation equipment.
(ii) Hazard assessment (facility specific).	(A) Identification of all likely fire initiation scenarios (including those resulting from maintenance and repair activities). For each scenario, discuss its potential severity and identify the ignition and fuel sources.

For the use of a chemical fire-fighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	Including . . .
	(B) Estimates of the fire/radiant heat exposure that personnel could be subjected to. Show how you have considered designated muster areas and evacuation routes near fuel sources and have verified proper flare boom sizing for radiant heat exposure.
(iii) Human factors assessment (not facility specific).	(A) Descriptions of the fire-related training your employees and contractors have received. Include details on the length of training, whether the training was hands-on or classroom, the training frequency, and the topics covered during the training.
	(B) Descriptions of the training your employees and contractors have received in fire prevention, control of ignition sources, and control of fuel sources when the facility is occupied.
	(C) Descriptions of the instructions and procedures you have given to your employees and contractors on the actions they should take if a fire occurs. Include those instructions and procedures specific to evacuation. State how you convey this information to your employees and contractors on the platform.
(iv) Evacuation assessment (facility specific).	(A) A general discussion of your evacuation plan. Identify your muster areas (if applicable), both the primary and secondary evacuation routes, and the means of evacuation for both.
	(B) Description of the type, quantity, and location of lifesaving appliances available on the facility. Show how you have ensured that lifesaving appliances are located in the near vicinity of the escape routes.
	(C) Description of the types and availability of support vessels, whether the support vessels are equipped with a fire monitor, and the time needed for support vessels to arrive at the facility.
	(D) Estimates of the worst case time needed for personnel to evacuate the facility should a fire occur.
(v) Alternative protection assessment.	(A) Discussion of the reasons you are proposing to use an alternative fire prevention and control system.
	(B) Lists of the specific standards used to design the system, locate the equipment, and operate the equipment/system.
	(C) Description of the proposed alternative fire prevention and control system/equipment. Provide details on the type, size, number, and location of the prevention and control equipment.
	(D) Description of the testing, inspection, and maintenance program you will use to maintain the fire prevention and control equipment in an operable condition. Provide specifics regarding the type of inspection, the personnel who conduct the inspections, the inspection procedures, and documentation and recordkeeping.
(vi) Conclusion	A summary of your technical evaluation showing that the alternative system provides an equivalent level of personnel protection for the specific hazards located on the facility.

(d) On major or minor platforms, if BSEE has approved your request to use a chemical-only fire suppressant system in lieu of a water system under paragraphs (b) and (c) of this section, and if you make an insignificant change to your platform subsequent to that approval, you must document the change and maintain the documentation for the life of the facility at either the facility or nearest field office for BSEE review and/or inspection. Do not submit this documentation to the District Manager. However, if you make a significant change to your platform (e.g., placing a storage vessel with a capacity of 100 barrels or more on the facility, adding production equipment), or if you plan to man an unmanned platform temporarily, you must submit a new request for approval, including an updated risk assessment if previously required, to the appropriate District Manager. You must maintain, for the life of the facility, the most recent documentation that you submitted to BSEE at the facility or nearest field office.

§ 250.861 Foam firefighting systems.

When you install foam firefighting systems as part of a firefighting system that protects production handling areas, you must:

(a) Annually conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration;

(b) Annually send samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing. You must have the sample tested to determine the specific gravity, pH, percentage of water dilution, and solid content. Based on these results, the foam must be certified by an authorized representative of the manufacturer as suitable firefighting foam consistent with the original manufacturer's specifications. The certification document must be

readily accessible for field inspection. In lieu of sampling and certification, you may choose to replace the total inventory of foam with suitable new stock;

(c) Ensure that the quantity of concentrate meets design requirements, and that tanks or containers are kept full, with space allowed for expansion.

§ 250.862 Fire and gas-detection systems.

For production processing areas only:

(a) You must install fire (flame, heat, or smoke) sensors in all enclosed classified areas. You must install gas sensors in all inadequately ventilated, enclosed classified areas.

(1) 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. An acceptable method of providing adequate ventilation is one that provides 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.

(2) Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more than 4 of their 6 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.

(3) A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500 (incorporated by reference as specified in § 250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (incorporated by reference as specified in § 250.198).

(b) All detection systems must be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas-concentration levels must be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(c) 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. A gas detection system is not required for living quarters and doghouses that do not contain a gas source and that are not located in a classified area.

(d) The District Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(e) Fire- and gas-detection systems must be an approved type, and designed and installed in accordance with API RP 14C, API RP 14G, API RP 14F, API RP 14FZ, API RP 500, and API RP 505 (all incorporated by reference as specified in § 250.198), provided that, if compliance with any provision of those standards would be in conflict with applicable regulations of the U.S. Coast Guard, compliance with the U.S. Coast Guard regulations controls.

§ 250.863 Electrical equipment.

You must design, install, and maintain electrical equipment and systems in accordance with the requirements in § 250.114.

§ 250.864 Erosion.

You must have a program of erosion control in effect for wells or fields that have a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. You must maintain records for each lease that indicate the wells that have erosion-control programs in effect. You must also maintain the results of the programs for at least 2 years and make them available to BSEE upon request.

§ 250.865 Surface pumps.

(a) You must equip pump installations with the protective equipment required in API RP 14C, Appendix A—A.7, Pumps (incorporated by reference as specified in § 250.198).

(b) You must use pressure recording devices to establish the new operating pressure ranges for pump discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over

time intervals that are no less than 4 hours and no more than 30 days long. You must only maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor	Must be no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line.	Must be set sufficiently below the maximum allowable working pressure of the discharge piping. The PSH must also be set at least 5 percent or 5 psi (whichever is greater) below the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.
(2) PSL sensor	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the discharge line in which it is installed.	

(d) The PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump coming into service, whichever is sooner.

(e) You may exclude the PSH and PSL sensors on small, low-volume pumps such as chemical injection-type pumps. This is acceptable if such a pump is used as a sump pump or transfer pump, has a discharge rating of less than ½ gallon per minute (gpm), discharges into piping that is 1 inch or less in diameter, and terminates in piping that is 2 inches or larger in diameter.

(f) You must install a TSE in the immediate vicinity of all pumps in hydrocarbon service or those powered by platform fuel gas.

(g) The pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver as appropriate for the pump type and service.

§ 250.866 Personnel safety equipment.

You must maintain all personnel safety equipment located on a facility, whether required or not, in good working condition.

§ 250.867 Temporary quarters and temporary equipment.

(a) You must equip temporary quarters with all safety devices required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198). The District Manager must approve the safety system/safety devices associated with the temporary quarters prior to installation.

(b) The District Manager may require you to install a temporary firewater system for temporary quarters in production processing areas or other classified areas.

(c) Temporary equipment associated with the production process system, including equipment used for well testing and/or well clean-up, must be approved by the District Manager.

(d) The District Manager must approve temporary generators that would require a change to the electrical one-line diagram in § 250.842(a).

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 250.868 Non-metallic piping.

On fixed OCS facilities, you may use non-metallic piping (such as that made from polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass) only in accordance with the requirements of § 250.841(b).

§ 250.869 General platform operations.

(a) Surface or subsurface safety devices must not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing. You may take only the minimum number of safety devices out of service. Personnel must 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 must be flagged. A designated visual indicator must be used to identify the bypassed safety device. You must follow the monitoring procedures as follows:

(1) If you are using a non-computer-based system, meaning your safety system operates primarily with pneumatic supply or non-programmable electrical systems, you must monitor bypassed safety devices by positioning monitoring personnel at either the control panel for the bypassed safety device, or at the bypassed safety device, or at the component that the bypassed safety device would be monitoring when in service. You must also ensure that monitoring personnel are able to view all relevant essential operating conditions until all bypassed safety devices are placed back in service and are able to initiate shut-in action in the event of an abnormal condition.

(2) If you are using a computer-based technology system, meaning a computer-controlled electronic safety system such as supervisory control and data acquisition and remote terminal units, you must monitor bypassed safety devices by maintaining instantaneous communications at all times among remote monitoring personnel and the personnel performing maintenance, testing, or startup. Until all bypassed safety devices are placed back in service, you must also position monitoring personnel at a designated control station that is capable of the following:

(i) Displaying all relevant essential operating conditions that affect the bypassed safety device, well, pipeline, and process component. If electronic display of all relevant essential conditions is not possible, you must have field personnel monitoring the level gauges (sight glass) and pressure gauges in order to know the current operating conditions. You must be in communication with all field personnel monitoring the gauges;

(ii) Controlling the production process equipment and the entire safety system;

(iii) Displaying a visual indicator when safety devices are placed in the bypassed mode; and

(iv) Upon command, overriding the bypassed safety device and initiating shut-in action in the event of an abnormal condition.

(3) You must not bypass for startup any element of the emergency support system or other support system required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198) without first receiving BSEE approval to depart from this operating procedure. These systems include, but are not limited to:

(i) The ESD system to provide a method to manually initiate platform shutdown by personnel observing abnormal conditions or undesirable events. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(ii) The fire loop system to sense the heat of a fire and initiate platform shutdown, and other fire detection devices (flame, thermal, and smoke) that are used to enhance fire detection capability. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(iii) The combustible gas detection system to sense the presence of hydrocarbons and initiate alarms and platform shutdown before gas concentrations reach the lower explosive limit;

(iv) Adequate ventilation;

(v) The containment system to collect escaped liquid hydrocarbons and initiate platform shutdown;

(vi) Subsurface safety valves, including those that are self-actuated (subsurface-controlled SSSVs) or those that are activated by an ESD system and/or a fire loop (surface-controlled SSSV). You do not have to receive approval from the District Manager for routine operations in accordance with § 250.817;

(vii) The pneumatic supply system; and

(viii) The system for discharging gas to the atmosphere.

(4) In instances where components of the ESD, as listed in paragraph (a)(3) of this section, are bypassed for maintenance, precautions must be taken to

provide the equivalent level of protection that existed prior to the bypass.

(b) When wells are disconnected from producing facilities and blind flanged, or equipped with a tubing plug, or the master valves have been locked closed, you are not required to comply with the provisions of API RP 14C (incorporated by reference as specified in § 250.198) or this regulation concerning the following:

(1) Automatic fail-close SSVs on wellhead assemblies, and

(2) The PSH and PSL sensors in flowlines from wells.

(c) 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 testing in accordance with API RP 14C (incorporated by reference as specified in § 250.198), or this subpart is not required, with the exception of the PSV, unless the vessel is open to the atmosphere.

(d) All open-ended lines connected to producing facilities and wells must be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(e) On all new production safety system installations, component process control devices and component safety devices must not be installed utilizing the same sensing points.

(f) All pneumatic control panels and computer based control stations must be labeled according to API RP 14C nomenclature.

§ 250.870 Time delays on pressure safety low (PSL) sensors.

(a) You may apply industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment. If the device may be bypassed for greater than 45 seconds, you must monitor the bypassed devices in accordance with § 250.869(a). You must document on your field test records any use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows:

(1) Class B safety devices have logic that allows for the PSL sensors to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). Examples include sensors used in conjunction with the design of pump and compressor panels such as PSL sensors, lubricator no-flows, and high-water jacket temperature shutdowns.

(2) Class C safety devices have logic that allows for the PSL sensors to be bypassed until the component comes into full service (*i.e.*, the time at which the startup pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized pressure, and the PSL sensor clears). If a Class C safety device is bypassed, you must monitor the device until it is in full service.

(3) Class B/C safety devices have logic that allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that the PSL sensors are not unnecessarily bypassed during startup and idle operations, (e.g., Class B/C bypass circuitry activates when a pump is shut down during normal operations). The PSL sensor remains bypassed until the pump's start circuitry is activated and either:

(i) The Class B timer expires no later than 45 seconds from start activation, or

(ii) The Class C bypass is initiated until the pump builds up pressure above the PSL sensor set point and the PSL sensor comes into full service.

(b) If you do not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period on process and product transport equipment during startup and idle operations, you must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

§ 250.871 Welding and burning practices and procedures.

All welding, burning, and hot-tapping activities must be conducted according to the specific requirements in § 250.113.

§ 250.872 Atmospheric vessels.

(a) You must equip atmospheric vessels used to process and/or store liquid hydrocarbons or other Class I liquids as

described in API RP 500 or 505 (both incorporated by reference in § 250.198) with protective equipment identified in API RP 14C, section A.5 (incorporated by reference in § 250.198). Transport tanks approved by the U.S. Department of Transportation, that are sealed and not connected via interconnected piping to the production process train and that are used only for storage of refined liquid hydrocarbons or Class I liquids, are not required to be equipped with the protective equipment identified in API RP 14C, section A.5. The atmospheric vessels connected to the process system that contains a Class I liquid and the associated pumps must be reflected on the design documents listed in § 250.842(a)(1) through (4) and (b)(3).

(b) You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality.

(c) You must ensure that all atmospheric vessels are designed, installed, and maintained to prevent pollution, including the displacement of oil out of an overboard water outlet, as required by § 250.300(b)(3) and (4).

[83 FR 49259, Sept. 28, 2018]

§ 250.873 Subsea gas lift requirements.

If you choose to install a subsea gas lift system, you must design your system as approved in your DWOP or as follows:

(a) Design the gas lift supply pipeline in accordance with API RP 14C (incorporated by reference as specified in § 250.198) for the gas lift supply system located on the platform.

(b) Meet the applicable requirements in the following table:

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in § 250.198) gas-lift shutdown valve (GLSDV), and . . .	FSV on the gas-lift supply pipeline . . .	PSHL on the gas-lift supply . . .	API Spec 6A and API Spec 6AV1 manual isolation valve . . .	
(1) Subsea pipelines, pipeline risers, or manifolds via an external gas lift pipeline or umbilical.	Meet all of the requirements for the BSDV described in §§ 250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	on the platform upstream (inboard) of the GLSDV.	pipeline on the platform downstream (out board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. (ii) Install an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. (iii) Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in § 250.198) gas-lift shutdown valve (GLSDV), and . . .	FSV on the gas-lift supply pipeline . . .	PSHL on the gas-lift supply . . .	API Spec 6A and API Spec 6AV1 manual isolation valve . . .	
(2) Subsea well(s) through the casing string via an external gas lift pipeline or umbilical.	Meet all of the requirements for the GLSDV described in §§ 250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical).	on the platform upstream (inboard) of the GLSDV.	pipeline on the platform downstream (out board) of the GLSDV.	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated..	(i) Install an actuated, fail-safe-closed GLIV on the gas lift supply pipeline near the wellhead to provide the dual function of containing annular pressure and shutting off the gas lift supply gas. (ii) If your subsea tree or tubing head is equipped with an annulus master valve (AMV) or an annulus wing valve (AWV), one of these may be designated as the GLIV. (iii) Consider installing the GLIV external to the subsea tree to facilitate repair and or replacement if necessary.
(3) Pipeline risers via a gas-lift line contained within the pipeline riser.	Meet all of the requirements for the GLSDV described in §§ 250.835(a), (b), and (d) and 250.836 on the gas-lift supply pipeline. Attach the GLSDV by flanged connection directly to the ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser. To facilitate the repair or replacement of the GLSDV or production riser BSDV, you may install a manual isolation valve between the GLSDV and the ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser, or outboard of the production riser BSDV and inboard of the ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser.	upstream (inboard) of the GLSDV.	flowline upstream (inboard) of the FSV.	downstream (out board) of the GLSDV.	(i) Ensure that the gas-lift supply flowline from the gas-lift compressor to the GLSDV is pressure-rated for the MAOP of the pipeline riser. (ii) Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (iii) Ensure that the gas-lift compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iv) Suspend and seal the gas-lift flowline contained within the production riser in a flanged ANSI/API Spec. 6A component such as an ANSI/API Spec. 6A tubing head and tubing hanger or a component designed, constructed, tested, and installed to the requirements of ANSI/API Spec. 6A. (v) Ensure that all potential leak paths upstream or near the production riser BSDV on the platform provide the same level of safety and environmental protection as the production riser BSDV. (vi) Ensure that this complete assembly is fire-rated for 30 minutes.

(c) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with gas lift,

(2) Electro-hydraulic control system with gas lift with loss of communications,

(3) Direct-hydraulic control system with gas lift.

(d) Follow the gas lift system valve testing requirements according to the following table:

Type of gas lift system	Valve	Allowable leakage rate	Testing frequency
(1) Gas lifting a subsea pipeline, pipeline riser, or manifold via an external gas lift pipeline.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.
	GLIV	N/A	Function tested quarterly, not to exceed 120 days.
(2) Gas lifting a subsea well through the casing string via an external gas lift pipeline.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.
	GLIV	400 cc per minute of liquid or 15 scf per minute of gas..	Function tested quarterly, not to exceed 120 days
(3) Gas lifting the pipeline riser via a gas lift line contained within the pipeline riser.	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 24707, May 29, 2019]

§ 250.874 Subsea water injection systems.

If you choose to install a subsea water injection system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(a) Adhere to the water injection requirements described in API RP 14C (incorporated by reference as specified in § 250.198) for the water injection equipment located on the platform. In accordance with § 250.830, either a surface-controlled SSSV or a water injection valve (WIV) that is self-activated and not controlled by emergency shutdown (ESD) or sensor activation must be installed in a subsea water injection well.

(b) Equip a water injection pipeline with a surface FSV and water injection shutdown valve (WISDV) on the surface facility.

(c) Install a PSHL sensor upstream (in-board) of the FSV and WISDV.

(d) Use subsea tree(s), wellhead(s), connector(s), and tree valves, and surface-controlled SSSV or WIV associated with a water injection system that are rated for the maximum anticipated injection pressure.

(e) Consider the effects of hydrogen sulfide (H2S) when designing your water flood system, as required by § 250.805.

(f) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with water injection,

(2) Electro-hydraulic control system with water injection with loss of communications, and

(3) Direct-hydraulic control system with water injection.

(g) Comply with the following injection valve testing requirements:

(1) You must test your injection valves as provided in the following table:

Valve	Allowable leakage rate	Testing frequency
(i) WISDV	Zero leakage	Monthly, not to exceed 6 weeks between tests.
(ii) Surface-controlled SSSV or WIV	400 cc per minute of liquid or 15 scf per minute of gas	Semiannually, not to exceed 6 calendar months between tests.

(2) If a designated USV on a water injection well fails the applicable test under § 250.880(c)(4)(ii), you must notify the appropriate District Manager and request approval to designate another ANSI/API Spec 6A and API Spec. 6AV1 (both incorporated by reference in § 250.198) certified subsea valve as your USV.

(3) If a USV on a water injection well fails the test and the surface-controlled SSSV or WIV cannot be tested as required under (g)(1)(ii) of this section because of low reservoir pressure, you must submit a request to the appropriate District Manager with an alternative plan that ensures subsea shutdown capabilities.

(h) If you experience a loss of communications during water injection operations, you must comply with the following:

(1) Notify the appropriate District Manager within 12 hours after detecting loss of communication; and

(2) Obtain approval from the appropriate District Manager to continue to inject during the loss of communication.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49262, Sept. 28, 2018]

§ 250.875 Subsea pump systems.

If you choose to install a subsea pump system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(a) Include the installation of an isolation valve at the inlet of your subsea pump module.

(b) Include a PSHL sensor upstream of the BSDV, if the maximum possible discharge pressure of the subsea pump operating in a dead head condition (that is the maximum shut-in tubing pressure at the pump inlet and a closed BSDV) is less than the MAOP of the associated pipeline.

(c) If the maximum possible discharge pressure of the subsea pump operating in a dead head situation could be greater than the MAOP of the pipeline:

(1) Include, at minimum, 2 independent functioning PSHL sensors upstream of the subsea pump and 2 independent functioning PSHL sensors downstream of the pump, that:

(i) Are operational when the subsea pump is in service; and

(ii) Will, when activated, shut down the subsea pump, the subsea inlet isolation valve, and either the designated USV1, the USV2, or the alternate isolation valve.

(iii) If more than 2 PSHL sensors are installed both upstream and downstream of the subsea pump for operational flexibility, then 2 out of 3 voting logic may be implemented in which the subsea pump remains operational provided a minimum of 2 independent PSHL sensors are functional both upstream and downstream of the pump.

(2) Interlock the subsea pump motor with the BSDV to ensure that the pump cannot start or operate when the BSDV is closed, incorporate at a minimum the following permissive signals into the control system for your subsea pump, and ensure that the subsea pump is not able to be started or re-started unless:

(i) The BSDV is open;

(ii) All automated valves downstream of the subsea pump are open;

(iii) The upstream subsea pump isolation valve is open; and

(iv) All parameters associated with the subsea pump operation (e.g., pump temperature high, pump vibration high, pump suction pressure high, pump discharge pressure high, pump suction flow low) must be cleared (*i.e.*, within operational limits) or continuously monitored by personnel who observe visual indicators displayed at a designated control station and have the capability to initiate shut-in action in the event of an abnormal condition.

(3) Monitor the separator for seawater.

(4) Ensure that the subsea pump systems are controlled by an electro-hydraulic control system.

(d) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with a subsea pump;

(2) A loss of communication with the subsea well(s) and not a loss of communication with the subsea pump control system without an ESD or sensor activation;

(3) A loss of communication with the subsea pump control system, and not a loss of communication with the subsea well(s);

(4) A loss of communication with the subsea well(s) and the subsea pump control system.

(e) For subsea pump testing:

(1) Perform a complete subsea pump function test, including full shutdown, after any intervention or changes to the software and equipment affecting the subsea pump; and

(2) Test the subsea pump shutdown, including PSHL sensors both upstream and downstream of the pump, each quarter (not to exceed 120 days between tests). This testing may be performed concurrently with the ESD function test required by § 250.880(c)(4)(v).

§ 250.876 Fired and exhaust heated components.

No later than September 7, 2018, and at least once every 5 years thereafter, you must have qualified third-party inspect, and then you must repair or replace, as needed, the fire tube for tube-type heaters that are equipped with either automatically controlled natural or forced draft burners installed in either atmospheric or pressure vessels that heat hydrocarbons and/or glycol. If inspection indicates tube-type heater deficiencies, you must complete and document repairs or replacements. You must document the inspection results, retain such documentation for at least 5 years, and make the documentation available to BSEE upon request.

[83 FR 49262, Sept. 28, 2018]

§§ 250.877–250.879 [Reserved]

SAFETY DEVICE TESTING

§ 250.880 Production safety system testing.

(a) *Notification*. You must:

(1) Notify the District Manager at least 72 hours before you commence initial production on a facility as required in § 250.800(a)(2), in order for BSEE to conduct the preproduction inspection of the integrated safety system.

(2) Notify the District Manager upon commencement of production so that BSEE may conduct a complete inspection.

(3) Notify the District Manager and receive BSEE approval before you perform any subsea intervention that modifies the existing subsea infrastructure in a way that may affect the casing monitoring capabilities and testing frequencies specified in the table set forth in paragraph (c)(4) of this section.

(b) *Testing methodologies*. You must:

(1) Test safety valves and other equipment at the intervals specified in the tables set forth in paragraph (c) of this section or more frequently if operating conditions warrant; and

(2) Perform testing and inspections in accordance with API RP 14C, Appendix D (incorporated by reference as specified in § 250.198), and the additional requirements specified in the tables of this section or as approved in the DWOP for your subsea system.

(c) *Testing frequencies*. You must:

(1) Comply with the following testing requirements for subsurface safety devices on dry tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	Semi-annually, not to exceed 6 calendar months between tests. Also test in place when first installed or reinstalled. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to ANSI/API RP 14B (incorporated by reference in § 250.198) to ensure proper operation.
(ii) Subsurface-controlled SSSVs	Semi-annually, not to exceed 6 calendar months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple. The valve must be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced.

Item name	Testing frequency, allowable leakage rates, and other requirements
(iii) Tubing plug	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the plug must be removed, repaired, and reinstalled or replaced. An additional tubing plug may be installed in lieu of removal.
(iv) Injection valves	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired and reinstalled or replaced.

(2) Comply with the following testing requirements for surface valves:

Item name	Testing frequency and requirements
(i) PSVs	Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing. The main valve piston must be lifted during this test.
(ii) Automatic inlet SDVs that are actuated by a sensor on a vessel or compressor.	Once each calendar month, not to exceed 6 weeks between tests.
(iii) SDVs in liquid discharge lines and actuated by vessel low-level sensors.	Once each calendar month, not to exceed 6 weeks between tests.
(iv) SSVs	Once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API STD 6AV2 (incorporated by reference in § 250.198). If an SSV does not operate properly or if any gas and/or liquid fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(v) Flowline FSVs	Once each calendar month, not to exceed 6 weeks between tests. All flowline FSVs must be tested, including those installed on a host facility in lieu of being installed at a satellite well. You must test flowline FSVs for leakage in accordance with the test procedure specified in API RP 14C (incorporated by reference as specified in § 250.198). If leakage measured exceeds a liquid flow of 400 cubic centimeters per minute or a gas flow of 15 standard cubic feet per minute, the FSV must be repaired or replaced.

(3) Comply with the following testing requirements for surface safety systems and devices:

Item name	Testing frequency and requirements
(i) Pumps for firewater systems	Must be inspected and operated according to API RP 14G, Section 7.2 (incorporated by reference as specified in § 250.198).
(ii) Fire- (flame, heat, or smoke) and gas detection systems	Must be tested for operation and recalibrated every 3 months, not to exceed 120 days between tests, provided that testing can be performed in a non-destructive manner. Open flame or devices operating at temperatures that could ignite a methane-air mixture must not be used. All combustible gas-detection systems must be calibrated every 3 months.

Item name	Testing frequency and requirements
(iii) ESD systems	(A) Pneumatic based ESD systems must be tested for operation at least once each calendar month, not to exceed 6 weeks between tests. You must conduct the test 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. All stations must be checked for functionality at least once each calendar month, not to exceed 6 weeks between tests. No station may be reused until all stations have been tested. (B) Electronic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been tested. (C) Electronic/pneumatic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been used.
(iv) TSH devices	Must be tested for operation annually, not to exceed 12 calendar months between tests, excluding those addressed in paragraph (c)(3)(v) of this section and those that would be destroyed by testing. Those that could be destroyed by testing must be visually inspected and the circuit tested for operations at least once every 12 months.
(v) TSH shutdown controls installed on compressor installations that can be nondestructively tested.	Must be tested every 6 months and repaired or replaced as necessary.
(vi) Burner safety low	Must be tested annually, not to exceed 12 calendar months between tests.
(vii) Flow safety low devices	Must be tested annually, not to exceed 12 calendar months between tests.
(viii) Flame, spark, and detonation arrestors	Must be visually inspected annually, not to exceed 12 calendar months between inspections.
(ix) Electronic pressure transmitters and level sensors: PSH and PSL; LSH and LSL.	Must be tested at least once every 3 months, not to exceed 120 days between tests.
(x) Pneumatic/electronic switch PSH and PSL; pneumatic/electronic switch/electric analog with mechanical linkage LSH and LSL controls.	Must be tested at least once each calendar month, not to exceed 6 weeks between tests.

(4) Comply with the following testing requirements for subsurface safety devices and associated systems on subsea tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells).	Tested semiannually, not to exceed 6 months between tests. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to ANSI/API RP 14B (incorporated by reference in § 250.198) to ensure proper operation, or as approved in your DWOP.
(ii) USVs	Tested at least once every 3 calendar months, not to exceed 120 days between tests. If the device does not function properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired, and reinstalled or replaced.

Item name	Testing frequency, allowable leakage rates, and other requirements
(iii) BSDVs	Tested at least once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API STD 6AV2 for SSVs (incorporated by reference in § 250.198). If a BSDV does not operate properly or if any fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(iv) Electronic ESD logic	Tested at least once each calendar month, not to exceed 6 weeks between tests.
(v) Electronic ESD function	Tested at least once every 3 calendar months, not to exceed 120 days between tests. Shut-in at least one well during the ESD function test. If multiple wells are tied back to the same platform, a different well should be shut-in with each quarterly test.

(d) *Subsea wells*. (1) Any subsea well that is completed and disconnected from monitoring capability may not be disconnected for more than 24 months, unless authorized by BSEE.

(2) Any subsea well that is completed and disconnected from monitoring capability for more than 6 months must meet the following testing and other requirements:

(i) Each well must have 3 pressure barriers:

(A) A closed and tested surface-controlled SSSV,

(B) A closed and tested USV, and

(C) One additional closed and tested tree valve.

(ii) For new completed wells, prior to the rig leaving the well, the pressure barriers must be tested as follows:

(A) The surface-controlled SSSV must be tested for leakage in accordance with § 250.828(c);

(B) The USV and other pressure barrier must be tested to confirm zero leakage rate.

(iii) A sealing pressure cap must be installed on the flowline connection hub until the flowline is installed and connected. The pressure cap must be designed to accommodate monitoring for pressure between the production wing valve and cap. The pressure cap must also be designed so that a remotely operated vehicle can bleed pressure off, monitor for buildup, and confirm barrier integrity.

(iv) Pressure monitoring at the sealing pressure cap on the flowline connection hub must be performed in each well at intervals not to exceed 12 months from the time of initial testing of the pressure barrier (prior to demobilizing the rig from the field).

(v) You must have a drilling vessel capable of intervention into the disconnected well in the field or readily accessible for use until the wells are brought on line.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49262, Sept. 28, 2018]

§§ 250.881–250.889 [Reserved]

RECORDS AND TRAINING

§ 250.890 Records.

(a) You must maintain records that show the present status and history of each safety device. Your records must include dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

(b) You must maintain these records for at least 2 years. You must maintain the records at your field office nearest the OCS facility and a secure onshore location. These records must be available for review by a representative of BSEE.

(c) You must submit to the appropriate District Manager a contact list for all OCS facilities at least annually or when contact information is revised. The contact list must include:

(1) Designated operator name;

(2) Designated primary point of contact for the facility;

(3) Facility phone number(s), if applicable;

(4) Facility fax number, if applicable;

(5) Facility radio frequency, if applicable;

(6) Facility helideck rating and size, if applicable; and

(7) Facility records location if not contained on the facility.

§ 250.891 Safety device training.

You must ensure that personnel installing, repairing, testing, maintaining, and operating surface and subsurface safety devices, and personnel operating production platforms (including, but not limited to, separation, dehydration, compression, sweetening, and metering operations), are trained in accordance with the procedures in subpart O and subpart S of this part.

§§ 250.892–250.899 [Reserved]

Subpart I—Platforms and Structures

GENERAL REQUIREMENTS FOR PLATFORMS

§ 250.900 What general requirements apply to all platforms?

(a) You must design, fabricate, install, use, maintain, inspect, and assess all platforms and related structures on the Outer Continental Shelf (OCS) so as to ensure their structural integrity for the safe conduct of drilling, workover, and production operations. In doing this, you must consider the specific environmental conditions at the platform location.

(b) You must also submit an application under § 250.905 of this subpart and obtain the approval of the Regional Supervisor before performing any of the activities described in the following table:

Activity requiring application and approval	Conditions for conducting the activity
(1) Install a platform. This includes placing a newly constructed platform at a location or moving an existing platform to a new site.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) If you are installing a floating platform, you must also adhere to U.S. Coast Guard (USCG) regulations for the fabrication, installation, and inspection of floating OCS facilities.
(2) Major modification to any platform. This includes any structural changes that materially alter the approved plan or cause a major deviation from approved operations and any modification that increases loading on a platform by 10 percent or more.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) Before you make a major modification to a floating platform, you must obtain approval from both the BSEE and the USCG for the modification.
(3) Major repair of damage to any platform. This includes any corrective operations involving structural members affecting the structural integrity of a portion or all of the platform.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) Before you make a major repair to a floating platform, you must obtain approval from both the BSEE and the USCG for the repair.
(4) Convert an existing platform at the current location for a new purpose.	(i) The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing platform at the current location. (ii) At a minimum, your application must include: the converted platform's intended use; and a demonstration of the adequacy of the design and structural condition of the converted platform. (iii) If a floating platform, you must also adhere to USCG regulations for the fabrication, installation, and inspection of floating OCS facilities.
(5) Convert an existing mobile offshore drilling unit (MODU) for a new purpose.	(i) The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing MODU. (ii) At a minimum, your application must include: the converted MODU's intended location and use; a demonstration of the adequacy of the design and structural condition of the converted MODU; and a demonstration that the level of safety for the converted MODU is at least equal to that of re-used platforms. (iii) You must also adhere to USCG regulations for the fabrication, installation, and inspection of floating OCS facilities.

(c) Under emergency conditions, you may make repairs to primary structural elements to restore an existing permitted condition without submitting an application or receiving prior BSEE approval for up to 120-calendar days following an event. You must notify the Regional Supervisor of the damage that occurred within 24 hours of its discovery, and you must provide a written completion report to the Regional Supervisor of the repairs that were made within 1 week after completing the repairs. If you make emergency repairs on a floating platform, you must also notify the USCG.

(d) You must determine if your new platform or major modification to an existing platform is subject to the Platform Verification Program (PVP). Section 250.910 of this subpart fully describes the facilities that are subject to the PVP. If you determine that your platform is subject to the PVP, you must follow the requirements of §§ 250.909 through 250.918 of this subpart.

(e) You must submit notification of the platform installation date and the final as-built location data to the Regional Supervisor within 45-calendar days of completion of platform installation.

(1) For platforms not subject to the Platform Verification Program (PVP), BSEE will cancel the approved platform application 1 year after the approval has been granted if the platform has not been installed. If BSEE cancels the approval, you must resubmit your platform application and receive BSEE approval if you still plan to install the platform.

(2) For platforms subject to the PVP, cancellation of an approval will be on an individual platform basis. For these platforms, BSEE will identify the date when the installation approval will be cancelled (if installation has not occurred) during the application and approval process. If BSEE cancels your installation approval, you must resubmit your platform application and receive BSEE approval if you still plan to install the platform.

§ 250.901 What industry standards must your platform meet?

(a) In addition to the other requirements of this subpart, your plans for platform design, analysis, fabrication, installation, use, maintenance, inspection and assessment must, as appropriate, conform to:

(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95) and Commentary (ACI 318R–95) (incorporated by reference at § 250.198);

(2) ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997 (incorporated by reference at § 250.198);

(3) ANSI/AISC 360–05, Specification for Structural Steel Buildings, (as specified in § 250.198);

(4) American Petroleum Institute (API) Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, (as incorporated by reference in § 250.198);

(5) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, (as incorporated by reference in § 250.198);

(6) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, (as incorporated by reference in § 250.198);

(7) API Recommend Practice (RP) 2A–WSD, RP for Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design (as incorporated by reference in § 250.198);

(8) API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, (as incorporated by reference in § 250.198);

(9) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Drilling Units (as incorporated by reference in § 250.198);

(10) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), (as incorporated by reference in § 250.198);

(11) API RP 2SK, Recommended Practice for Design and Analysis of Station Keeping Systems for Floating Structures, (as incorporated by reference in § 250.198);

(12) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, (as incorporated by reference in § 250.198);

(13) API RP 2T, Recommended Practice for Planning, Designing and Constructing Tension Leg Platforms, (as incorporated by reference in § 250.198);

(14) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, (as incorporated by reference in § 250.198);

(15) American Society for Testing and Materials (ASTM) Standard C 33–07, approved December 15, 2007, Standard Specification for Concrete Aggregates (as incorporated by reference in § 250.198);

(16) ASTM Standard C 94/C 94M–07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete (as incorporated by reference in § 250.198);

(17) ASTM Standard C 150–07, approved May 1, 2007, Standard Specification for Portland Cement (as incorporated by reference in § 250.198);

(18) ASTM Standard C 330–05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete (as incorporated by reference in § 250.198);

(19) ASTM Standard C 595–08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements (as incorporated by reference in § 250.198);

(20) AWS D1.1, Structural Welding Code—Steel, including Commentary, (as incorporated by reference in § 250.198);

(21) AWS D1.4, Structural Welding Code—Reinforcing Steel, (as incorporated by reference in § 250.198);

(22) AWS D3.6M, Specification for Underwater Welding, (as incorporated by reference in § 250.198);

(23) NACE Standard MR0175, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, (as incorporated by reference in § 250.198);

(24) NACE Standard RP0176–2003, Item No. 21018, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production (as incorporated by reference in § 250.198).

(b) You must follow the requirements contained in the documents listed under paragraph (a) of this section insofar as they do not conflict with other provisions of 30 CFR part 250. You may use applicable provisions of these documents, as approved by the Regional Supervisor, for the design, fabrication, and installation of platforms such as spars, since standards specifically written for such structures do not exist. You may also use alternative codes, rules, or standards, as approved by the Regional Supervisor, under the conditions enumerated in § 250.141.

(c) For information on the standards mentioned in this section, and where they may be obtained, see § 250.198 of this part.

(d) The following chart summarizes the applicability of the industry standards listed in this section for fixed and floating platforms:

Industry standard	Applicable to . . .
(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95) and Commentary (ACI 318R–95), (2) ANSI/AISC 360–05, Specification for Structural Steel Buildings; (3) API Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions; (4) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions; (5) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico; (6) API RP 2A–WSD, RP for Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design; (7) ASTM Standard C 33–07, approved December 15, 2007, Standard Specification for Concrete Aggregates; (8) ASTM Standard C 94/C 94M–07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete; (9) ASTM Standard C 150–07, approved May 1, 2007, Standard Specification for Portland Cement; (10) ASTM Standard C 330–05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete; (11) ASTM Standard C 595–08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements;	Fixed and floating platform, as appropriate.

Industry standard	Applicable to . . .
(12) AWS D1.1, Structural Welding Code—Steel;	
(13) AWS D1.4, Structural Welding Code—Reinforcing Steel;	
(14) AWS D3.6M, Specification for Underwater Welding;	
(15) NACE Standard RP 0176–2003, Standard Recommended Practice (RP), Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production;	
(16) ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997,	Fixed platforms.
(17) API RP 14J, RP for Design and Hazards Analysis for Offshore Production Facilities;	Floating platforms.
(18) API RP 2FPS, RP for Planning, Designing, and Constructing, Floating Production Systems;	
(19) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs);	
(20) API RP 2SK, RP for Design and Analysis of Station Keeping Systems for Floating Structures;	
(21) API RP 2T, RP for Planning, Designing, and Constructing Tension Leg Platforms;	
(22) API RP 2SM, RP for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring;	
(23) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Drilling Units	

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.902 What are the requirements for platform removal and location clearance?

You must remove all structures according to §§ 250.1725 through 250.1730 of Subpart Q—Decommissioning Activities of this part.

§ 250.903 What records must I keep?

(a) You must compile, retain, and make available to BSEE representatives for the functional life of all platforms:

(1) The as-built drawings;

(2) The design assumptions and analyses;

(3) A summary of the fabrication and installation nondestructive examination records;

(4) The inspection results from the inspections required by § 250.919 of this subpart; and

(5) Records of repairs not covered in the inspection report submitted under § 250.919(b).

(b) You must record and retain the original material test results of all primary structural materials during all stages of construction. Primary material is material that, should it fail, would lead to a significant reduction in platform safety, structural reliability, or operating capabilities. Items such as steel brackets, deck stiffeners and secondary braces or beams would not generally be considered primary structural members (or materials).

(c) You must provide BSEE with the location of these records in the certification statement of your application for platform approval as required in § 250.905(j).

PLATFORM APPROVAL PROGRAM

§ 250.904 What is the Platform Approval Program?

(a) The Platform Approval Program is the BSEE basic approval process for platforms on the OCS. The requirements of the Platform Approval Program are described in §§ 250.904 through 250.908 of this subpart. Completing these requirements will satisfy BSEE criteria for approval of fixed platforms of a proven design that will be placed in the shallow water areas (≤400 ft.) of the Gulf of Mexico OCS.

(b) The requirements of the Platform Approval Program must be met by all platforms on the OCS. Additionally, if you want approval for a floating platform; a platform of unique design; or a platform being installed in deepwater (≤ 400 ft.) or a frontier area, you must also meet the requirements of the Platform Verification Program. The requirements of the Platform Verification Program are described in §§ 250.909 through 250.918 of this subpart.

§ 250.905 How do I get approval for the installation, modification, or repair of my platform?

The Platform Approval Program requires that you submit the information, documents, and fee listed in the

following table for your proposed project. In lieu of submitting the paper copies specified in the table, you may submit your application electronically in accordance with 30 CFR 250.186(a)(3).

Required submittal	Required contents	Other requirements
(a) Application cover letter	Proposed structure designation, lease number, area, name, and block number, and the type of facility your facility (e.g., drilling, production, quarters). The structure designation must be unique for the field (some fields are made up of several blocks); *i.e.* once a platform ''A'' has been used in the field there should never be another platform ''A'' even if the old platform ''A'' has been removed. Single well free standing caissons should be given the same designation as the well. All other structures are to be designated by letter designations.	You must submit three copies. If, your facility is subject to the Platform Verification Program (PVP), you must submit four copies.
(b) Location plat	Latitude and longitude coordinates, Universal Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection System, and distances in feet from the nearest block lines. These coordinates must be based on the NAD (North American Datum) 27 datum plane coordinate system.	Your plat must be drawn to a scale of 1 inch equals 2,000 feet and include the coordinates of the lease block boundary lines. You must submit three copies.
(c) Front, Side, and Plan View drawings	Platform dimensions and orientation, elevations relative to M.L.L.W. (Mean Lower Low Water), and pile sizes and penetration.	Your drawing sizes must not exceed 11″ × 17″. You must submit three copies (four copies for PVP applications).
(d) Complete set of structural drawings	The approved for construction fabrication drawings should be submitted including; e.g., cathodic protection systems; jacket design; pile foundations; drilling, production, and pipeline risers and riser tensioning systems; turrets and turret-and-hull interfaces; mooring and tethering systems; foundations and anchoring systems.	Your drawing sizes must not exceed 11″ × 17″. You must submit one copy.
(e) Summary of environmental data	A summary of the environmental data described in the applicable standards referenced under § 250.901(a) of this subpart and in § 250.198 of Subpart A, where the data is used in the design or analysis of the platform. Examples of relevant data include information on waves, wind, current, tides, temperature, snow and ice effects, marine growth, and water depth.	You must submit one copy.
(f) Summary of the engineering design data.	Loading information (e.g., live, dead, environmental), structural information (e.g., design-life; material types; cathodic protection systems; design criteria; fatigue life; jacket design; deck design; production component design; pile foundations; drilling, production, and pipeline risers and riser tensioning systems; turrets and turret-and-hull interfaces; foundations, foundation pilings and templates, and anchoring systems; mooring or tethering systems; fabrication and installation guidelines), and foundation information (e.g., soil stability, design criteria).	You must submit one copy.
(g) Project-specific studies used in the platform design or installation.	All studies pertinent to platform design or installation, e.g., oceanographic and/or soil reports including the overall site investigative report required in § 250.906.	You must submit one copy of each study.

Required submittal	Required contents	Other requirements
(h) Description of the loads imposed on the facility.	Loads imposed by jacket; decks; production components; drilling, production, and pipeline risers, and riser tensioning systems; turrets and turret-and-hull interfaces; foundations, foundation pilings and templates, and anchoring systems; and mooring or tethering systems.	You must submit one copy.
(i) Summary of safety factors utilized	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.	You must submit one copy.
(j) A copy of the in-service inspection plan	This plan is described in § 250.919	You must submit one copy.
(k) Certification statement	The following statement: ''The design of this structure has been certified by a recognized classification society, or a registered civil or structural engineer or equivalent, or a naval architect or marine engineer or equivalent, specializing in the design of offshore structures. The certified design and as-built plans and specifications will be on file at (give location)''.	An authorized company representative must sign the statement. You must submit one copy.
(l) Payment of the service fee listed in § 250.125.		

§ 250.906 What must I do to obtain approval for the proposed site of my platform?

(a) *Shallow hazards surveys*. You must perform a high-resolution or acoustic-profiling survey to obtain information on the conditions existing at and near the surface of the seafloor. You must collect information through this survey sufficient to determine the presence of the following features and their likely effects on your proposed platform:

(1) Shallow faults;

(2) Gas seeps or shallow gas;

(3) Slump blocks or slump sediments;

(4) Shallow water flows;

(5) Hydrates; or

(6) Ice scour of seafloor sediments.

(b) *Geologic surveys*. You must perform a geological survey relevant to the design and siting of your platform. Your geological survey must assess:

(1) Seismic activity at your proposed site;

(2) Fault zones, the extent and geometry of faulting, and attenuation effects of geologic conditions near your site; and

(3) For platforms located in producing areas, the possibility and effects of seafloor subsidence.

(c) *Subsurface surveys*. Depending upon the design and location of your proposed platform and the results of the shallow hazard and geologic surveys, the Regional Supervisor may require you to perform a subsurface survey. This survey will include a testing program for investigating the stratigraphic and engineering properties of the soil that may affect the foundations or anchoring systems for your facility. The testing program must include adequate in situ testing, boring, and sampling to examine all important soil and rock strata to determine its strength classification, deformation properties, and dynamic characteristics. If required to perform a subsurface survey, you must prepare and submit to the Regional Supervisor a summary report to briefly describe the results of your soil testing program, the various field and laboratory test methods employed, and the applicability of these methods as they pertain to the quality of the samples, the type of soil, and the anticipated design application. You must explain how the engineering properties of each soil stratum affect the design of your platform. In your explanation you must describe the uncertainties inherent in your overall testing program, and the reliability and applicability of each test method.

(d) *Overall site investigation report.* You must prepare and submit to the Regional Supervisor an overall site investigation report for your platform that integrates the findings of your shallow hazards surveys and geologic surveys, and, if required, your subsurface surveys. Your overall site investigation report must include analyses of the potential for:

(1) Scouring of the seafloor;

(2) Hydraulic instability;

(3) The occurrence of sand waves;

(4) Instability of slopes at the platform location;

(5) Liquefaction, or possible reduction of soil strength due to increased pore pressures;

(6) Degradation of subsea permafrost layers;

(7) Cyclic loading;

(8) Lateral loading;

(9) Dynamic loading;

(10) Settlements and displacements;

(11) Plastic deformation and formation collapse mechanisms; and

(12) Soil reactions on the platform foundations or anchoring systems.

§ 250.907 Where must I locate foundation boreholes?

(a) For fixed or bottom-founded platforms and tension leg platforms, your maximum distance from any foundation pile to a soil boring must not exceed 500 feet.

(b) For deepwater floating platforms which utilize catenary or taut-leg moorings, you must take borings at the most heavily loaded anchor location, at the anchor points approximately 120 and 240 degrees around the anchor pattern from that boring, and, as necessary, other points throughout the anchor pattern to establish the soil profile suitable for foundation design purposes.

§ 250.908 What are the minimum structural fatigue design requirements?

(a) API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms (as incorporated by reference in § 250.198), requires that the design fatigue life of each joint and member be twice the intended service life of the structure. When designing your platform, the following table provides minimum fatigue life safety factors for critical structural members and joints.

If . . .	Then . . .
(1) There is sufficient structural redundancy to prevent catastrophic failure of the platform or structure under consideration,	The results of the fatigue analysis must indicate a minimum calculated life of twice the design life of the platform.
(2) There is not sufficient structural redundancy to prevent catastrophic failure of the platform or structure,	The results of a fatigue analysis must indicate a minimum calculated life or three times the design life of the platform.
(3) The desirable degree of redundancy is significantly reduced as a result of fatigue damage,	The results of a fatigue analysis must indicate a minimum calculated life of three times the design life of the platform.

(b) The documents incorporated by reference in § 250.901 may require larger safety factors than indicated in paragraph (a) of this section for some key components. When the documents incorporated by reference require a larger safety factor than the chart in paragraph (a) of this section, the requirements of the incorporated document will prevail.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

PLATFORM VERIFICATION PROGRAM

§ 250.909 What is the Platform Verification Program?

The Platform Verification Program is the BSEE approval process for ensuring that floating platforms; platforms of a new or unique design; platforms in seismic areas; or platforms located in deepwater or frontier areas meet stringent requirements for design and construction. The program is applied during construction of new platforms and major modifications of, or repairs to, existing platforms. These requirements are in addition to the requirements of

the Platform Approval Program described in §§ 250.904 through 250.908 of this subpart.

§ 250.910 Which of my facilities are subject to the Platform Verification Program?

(a) All new fixed or bottom-founded platforms that meet any of the following five conditions are subject to the Platform Verification Program:

(1) Platforms installed in water depths exceeding 400 feet (122 meters);

(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.

(b) All new floating platforms are subject to the Platform Verification Program to the extent indicated in the following table:

If . . .	Then . . .
(1) Your new floating platform is a buoyant offshore facility that does not have a ship-shaped hull,	The entire platform is subject to the Platform Verification Program including the following associated structures: (i) Drilling, production, and pipeline risers, and riser tensioning systems (each platform must be designed to accommodate all the loads imposed by all risers and riser does not have tensioning systems); (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.
(2) Your new floating platform is a buoyant offshore facility with a ship-shaped hull,	Only the following structures that may be associated with a floating platform are subject to the Platform Verification Program: (i) Drilling, production, and pipeline risers, and riser tensioning systems (each platform must be designed to accommodate all the loads imposed by all risers and riser tensioning systems); (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) If a platform is originally subject to the Platform Verification Program, then the conversion of that platform at that same site for a new purpose, or making a major modification of, or major repair to, that platform, is also subject to the Platform Verification Program. A major modification includes any modification that increases loading on a platform by 10 percent or more. A major repair is a corrective operation involving structural members affecting the structural integrity of a portion or all of the platform. Before you make a major modification or repair to a floating platform, you must obtain approval from both the BSEE and the USCG.

(d) The applicability of Platform Verification Program requirements to other types of facilities will be determined by BSEE on a case-by-case basis.

§ 250.911 If my platform is subject to the Platform Verification Program, what must I do?

If your platform, conversion, or major modification or repair meets the criteria in § 250.910, you must:

(a) Design, fabricate, install, use, maintain and inspect your platform, conversion, or major modification or repair to your platform according to the requirements of this subpart, and the applicable documents listed in § 250.901(a) of this subpart;

(b) Comply with all the requirements of the Platform Approval Program found in §§ 250.904 through 250.908 of this subpart.

(c) Submit for the Regional Supervisor's approval three copies each of the design verification, fabrication verification, and installation verification plans required by § 250.912;

(d) Submit a complete schedule of all phases of design, fabrication, and installation for the Regional Supervisor's approval. You must include a project management timeline, Gantt Chart, that depicts when interim and final reports required by §§ 250.916, 250.917, and 250.918 will be submitted to the Regional Supervisor for each phase. On the timeline, you must break-out the specific scopes of work that inherently stand alone (e.g., deck, mooring systems, tendon systems, riser systems, turret systems).

(e) Include your nomination of a Certified Verification Agent (CVA) as a part of each verification plan required by § 250.912;

(f) Follow the additional requirements in §§ 250.913 through 250.918;

(g) Obtain approval for modifications to approved plans and for major deviations from approved installation procedures from the Regional Supervisor; and

(h) Comply with applicable USCG regulations for floating OCS facilities.

§ 250.912 What plans must I submit under the Platform Verification Program?

If your platform, associated structure, or major modification meets the criteria in § 250.910, you must submit the following plans to the Regional Supervisor for approval:

(a) *Design verification plan*. You may submit your design verification plan to BSEE with or subsequent to the submittal of your Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD) to BOEM. Your design verification must be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer or equivalent, or a naval architect or marine engineer or equivalent, with previous experience in directing the design of similar facilities, systems, structures, or equipment. For floating platforms, you must ensure that the requirements of the USCG for structural integrity and stability, e.g., verification of center of gravity, *etc.*, have been met. Your design verification plan must include the following:

(1) All design documentation specified in § 250.905 of this subpart;

(2) Abstracts of the computer programs used in the design process; and

(3) A summary of the major design considerations and the approach to be used to verify the validity of these design considerations.

(b) *Fabrication verification plan*. The Regional Supervisor must approve your fabrication verification plan before you may initiate any related operations. Your fabrication verification plan must include the following:

(1) Fabrication drawings and material specifications for artificial island structures and major members of concrete-gravity and steel-gravity structures;

(2) For jacket and floating structures, all the primary load-bearing members included in the space-frame analysis; and

(3) 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 for welds and materials; and

(vii) Quality assurance procedures.

(c) *Installation verification plan*. The Regional Supervisor must approve your installation verification plan before you may initiate any related operations. Your installation verification plan must include:

(1) A summary description of the planned marine operations;

(2) Contingencies considered;

(3) Alternative courses of action; and

(4) An identification of the areas to be inspected. You must specify the acceptance and rejection criteria to be used for any inspections conducted during installation, and for the post-installation verification inspection.

(d) You must combine fabrication verification and installation verification plans for manmade islands or platforms fabricated and installed in place.

§ 250.913 When must I resubmit Platform Verification Program plans?

(a) You must resubmit any design verification, fabrication verification, or installation verification plan to the Regional Supervisor for approval if:

(1) The CVA changes;

(2) The CVA's or assigned personnel's qualifications change; or

(3) The level of work to be performed changes.

(b) If only part of a verification plan is affected by one of the changes described in paragraph (a) of this section, you can resubmit only the affected part. You do not have to resubmit the summary of technical details unless you make changes in the technical details.

§ 250.914 How do I nominate a CVA?

(a) As part of your design verification, fabrication verification, or installation verification plan, you must nominate a CVA for the Regional Supervisor's approval. You must specify whether the nomination is for the design, fabrication, or installation phase of verification, or for any combination of these phases.

(b) For each CVA, you must submit a list of documents to be forwarded to the CVA, and a qualification statement that includes the following:

(1) Previous experience in third-party verification or experience in the design, fabrication, installation, or major modification of offshore oil and gas platforms. This should include fixed platforms, floating platforms, man-made islands, other similar marine structures, and related systems and equipment;

(2) Technical capabilities of the individual or the primary staff for the specific project;

(3) Size and type of organization or corporation;

(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;

(5) Ability to perform the CVA functions for the specific project considering current commitments;

(6) Previous experience with BSEE requirements and procedures;

(7) The level of work to be performed by the CVA.

§ 250.915 What are the CVA's primary responsibilities?

(a) The CVA must conduct specified reviews according to §§ 250.916, 250.917, and 250.918 of this subpart.

(b) Individuals or organizations acting as CVAs must not function in any capacity that would create a conflict of interest, or the appearance of a conflict of interest.

(c) The CVA must consider the applicable provisions of the documents listed in § 250.901(a); the alternative codes, rules, and standards approved under § 250.901(b); and the requirements of this subpart.

(d) The CVA is the primary contact with the Regional Supervisor and is directly responsible for providing immediate reports of all incidents that affect the design, fabrication and installation of the platform.

§ 250.916 What are the CVA's primary duties during the design phase?

(a) The CVA must use good engineering judgment and practices in conducting an independent assessment of the design of the platform, major modification, or repair. The CVA must ensure that the platform, major modification, or repair is designed to withstand the environmental and functional load conditions appropriate for the intended service life at the proposed location.

(b) Primary duties of the CVA during the design phase include the following:

Type of facility . . .	The CVA must . . .
(1) For fixed platforms and non-ship-shaped floating facilities,	Conduct an independent assessment of all proposed: (i) Planning criteria; (ii) Operational requirements; (iii) Environmental loading data; (iv) Load determinations; (v) Stress analyses; (vi) Material designations; (vii) Soil and foundation conditions; (viii) Safety factors; and

Type of facility . . .	The CVA must . . .
(2) For all floating facilities,	(ix) Other pertinent parameters of the proposed design. Ensure that the requirements of the U.S. Coast Guard for structural integrity and stability, e.g., verification of center of gravity, *etc.,* have been met. The CVA must also consider: (i) Drilling, production, and pipeline risers, and riser tensioning systems; (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) The CVA must submit interim reports and a final report to the Regional Supervisor, and to you, during the design phase in accordance with the approved schedule required by § 250.911(d). In each interim and final report the CVA must:

(1) Provide a summary of the material reviewed and the CVA's findings;

(2) In the final CVA report, make a recommendation that the Regional Supervisor either accept, request modifications, or reject the proposed design unless such a recommendation has been previously made in an interim report;

(3) Describe the particulars of how, by whom, and when the independent review was conducted; and

(4) Provide any additional comments the CVA deems necessary.

§ 250.917 What are the CVA's primary duties during the fabrication phase?

(a) The CVA must use good engineering judgment and practices in conducting an independent assessment of the fabrication activities. The CVA must monitor the fabrication of the platform or major modification to ensure that it has been built according to the approved design and the fabrication plan. If the CVA finds that fabrication procedures are changed or design specifications are modified, the CVA must inform you. If you accept the modifications, then the CVA must so inform the Regional Supervisor.

(b) Primary duties of the CVA during the fabrication phase include the following:

Type of facility . . .	The CVA must . . .
(1) For all fixed platforms and non-ship-shaped floating facilities,	Make periodic onsite inspections while fabrication is in progress and must verify the following fabrication items, as appropriate: (i) Quality control by lessee and builder; (ii) Fabrication site facilities; (iii) Material quality and identification methods; (iv) Fabrication procedures specified in the approved plan, and adherence to such procedures; (v) Welder and welding procedure qualification and identification; (vi) Structural tolerances specified and adherence to those tolerances; (vii) The nondestructive examination requirements, and evaluation results of the specified examinations; (viii) Destructive testing requirements and results; (ix) Repair procedures; (x) Installation of corrosion-protection systems and splash-zone protection; (xi) Erection procedures to ensure that overstressing of structural members does not occur; (xii) Alignment procedures; (xiii) Dimensional check of the overall structure, including any turrets, turret-and-hull interfaces, any mooring line and chain and riser tensioning line segments; and (xiv) Status of quality-control records at various stages of fabrication.
(2) For all floating facilities,	Ensure that the requirements of the U.S. Coast Guard floating for structural integrity and stability, e.g., verification of center of gravity, *etc.,* have been met. The CVA must also consider: (i) Drilling, production, and pipeline risers, and riser tensioning systems (at least for the initial fabrication of these elements); (ii) Turrets and turret-and-hull interfaces; (iii) Foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) The CVA must submit interim reports and a final report to the Regional Supervisor, and to you, during the fabrication phase in accordance with the approved schedule required by § 250.911(d). In each interim and final report the CVA must:

(1) Give details of how, by whom, and when the independent monitoring activities were conducted;

(2) Describe the CVA's activities during the verification process;

(3) Summarize the CVA's findings;

(4) Confirm or deny compliance with the design specifications and the approved fabrication plan;

(5) In the final CVA report, make a recommendation to accept or reject the fabrication unless such a recommendation has been previously made in an interim report; and

(6) Provide any additional comments that the CVA deems necessary.

§ 250.918 What are the CVA's primary duties during the installation phase?

(a) The CVA must use good engineering judgment and practice in conducting an independent assessment of the installation activities.

(b) Primary duties of the CVA during the installation phase include the following:

The CVA must . . .	Operation or equipment to be inspected . . .
(1) Verify, as appropriate,	(i) Loadout and initial flotation operations; (ii) Towing operations to the specified location, and review the towing records; (iii) Launching and uprighting operations; (iv) Submergence operations; (v) Pile or anchor installations; (vi) Installation of mooring and tethering systems; (vii) Final deck and component installations; and (viii) Installation at the approved location according to the approved design and the installation plan.
(2) Witness (for a fixed or floating platform),	(i) The loadout of the jacket, decks, piles, or structures from each fabrication site; (ii) The actual installation of the platform or major modification and the related installation activities.
(3) Witness (for a floating platform),	(i) The loadout of the platform; (ii) The installation of drilling, production, and pipeline risers, and riser tensioning systems (at least for the initial installation of these elements); (iii) The installation of turrets and turret-and-hull interfaces; (iv) The installation of foundation pilings and templates, and anchoring systems; and (v) The installation of the mooring and tethering systems.
(4) Conduct an onsite survey,	Survey the platform after transportation to the approved location.
(5) Spot-check as necessary to determine compliance with the applicable documents listed in § 250.901(a); the alternative codes, rules and standards approved under § 250.901(b); the requirements listed in § 250.903 and §§ 250.906 through 250.908 of this subpart and the approved plans,	(i) Equipment; (ii) Procedures; and (iii) Recordkeeping.

(c) The CVA must submit interim reports and a final report to the Regional Supervisor, and to you, during the installation phase in accordance with the approved schedule required by § 250.911(d). In each interim and final report the CVA must:

(1) Give details of how, by whom, and when the independent monitoring activities were conducted;

(2) Describe the CVA's activities during the verification process;

(3) Summarize the CVA's findings;

(4) Confirm or deny compliance with the approved installation plan;

(5) In the final report, make a recommendation to accept or reject the installation unless such a recommendation has been previously made in an interim report; and

(6) Provide any additional comments that the CVA deems necessary.

INSPECTION, MAINTENANCE, AND ASSESSMENT OF PLATFORMS

§ 250.919 What in-service inspection requirements must I meet?

(a) You must submit a comprehensive in-service inspection report annually by November 1 to the Regional Supervisor that must include:

(1) A list of fixed and floating platforms you inspected in the preceding 12 months;

(2) The extent and area of inspection for both the above-water and underwater portions of the platform and the pertinent components of the mooring system for floating platforms;

(3) The type of inspection employed (e.g., visual, magnetic particle, ultrasonic testing);

(4) The overall structural condition of each platform, including a corrosion protection evaluation; and

(5) A summary of the inspection results indicating what repairs, if any, were needed.

(b) If any of your structures have been exposed to a natural occurrence (e.g., hurricane, earthquake, or tropical storm), the Regional Supervisor may require you to submit an initial report of all structural damage, followed by subsequent updates, which include the following:

(1) A list of affected structures;

(2) A timetable for conducting the inspections described in section 14.4.3 of API RP 2A–WSD (as incorporated by reference in § 250.198); and

(3) An inspection plan for each structure that describes the work you will perform to determine the condition of the structure.

(c) The Regional Supervisor may also require you to submit the results of the inspections referred to in paragraph (b)(2) of this section, including a description of any detected damage that may adversely affect structural integrity, an assessment of the structure's ability to withstand any anticipated environmental conditions, and any remediation plans. Under §§ 250.900(b)(3) and 250.905, you must obtain approval from BSEE before you make major repairs of any damage unless you meet the requirements of § 250.900(c).

§ 250.920 What are the BSEE requirements for assessment of fixed platforms?

(a) You must document all wells, equipment, and pipelines supported by the platform if you intend to use either the A–2 or A–3 assessment category. Assessment categories are defined in API RP 2A–WSD, Section 17.3 (as incorporated by reference in § 250.198). If BSEE objects to the assessment category you used for your assessment, you may need to redesign and/or modify the platform to adequately demonstrate that the platform is able to withstand the environmental loadings for the appropriate assessment category.

(b) You must perform an analysis check when your platform will have additional personnel, additional topside facilities, increased environmental or operational loading, inadequate deck height, or suffered significant damage (e.g., experienced damage to primary structural members or conductor guide trays or global structural integrity is adversely affected); or the exposure category changes to a more restrictive level (see Sections 17.2.1 through 17.2.5 of API RP 2A–WSD, incorporated by reference in § 250.198, for a description of assessment initiators).

(c) You must initiate mitigation actions for platforms that do not pass the assessment process of API RP 2A–WSD. You must submit applications for your mitigation actions (e.g., repair, modification, decommissioning) to the Regional Supervisor for approval before you conduct the work.

(d) The BSEE may require you to conduct a platform design basis check when the reduced environmental loading criteria contained in API RP 2A–WSD Section 17.6 are not applicable.

(e) By November 1, 2009, you must submit a complete list of all the platforms you operate, together with all the appropriate data to support the assessment category you assign to each platform and the platform assessment initiators (as defined in API RP 2A–WSD) to the Regional Supervisor. You must submit subsequent complete lists and the appropriate data to support the consequence-of-failure category every 5 years thereafter, or as directed by the Regional Supervisor.

(f) The use of Section 17, Assessment of Existing Platforms, of API RP 2A–WSD is limited to existing fixed structures that are serving their original approved purpose. You must obtain approval from the Regional Supervisor for any change in purpose of the platform, following the provisions of API RP 2A–WSD, Section 15, Re-use.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.921 How do I analyze my platform for cumulative fatigue?

(a) If you are required to analyze cumulative fatigue on your platform because of the results of an inspection or platform assessment, you must ensure that the safety factors for critical elements listed in § 250.908 are met or exceeded.

(b) If the calculated life of a joint or member does not meet the criteria of § 250.908, you must either mitigate the load, strengthen the joint or member, or develop an increased inspection process.

Subpart J—Pipelines and Pipeline Rights-of-Way

§ 250.1000 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 must be accompanied by payment of the service fee listed in § 250.125 and submitted to the Regional Supervisor and approval obtained before:

(1) Installation, modification, or abandonment of a lease term pipeline;

(2) Installation or modification of a right-of-way (other than lease term) pipeline; or

(3) Modification or relinquishment of a pipeline right-of way.

(c)(1) Department of the Interior (DOI) pipelines, as defined in § 250.1001, must meet the requirements in §§ 250.1000 through 250.1008.

(2) A pipeline right-of-way grant holder must identify in writing to the Regional Supervisor the operator of any pipeline located on its right-of-way, if the operator is different from the right-of-way grant holder.

(3) A producing operator must identify for its own records, on all existing pipelines located on its lease or right-of-way, the specific points at which operating responsibility transfers to a transporting operator.

(i) Each producing operator must, if practical, durably mark all of its above-water transfer points as of the date a pipeline begins service.

(ii) If it is not practical to durably mark a transfer point, and the transfer point is located above water, then the operator must identify the transfer point on a schematic located on the facility.

(iii) If a transfer point is located below water, then the operator must identify the transfer point on a schematic and provide the schematic to BSEE upon request.

(iv) If adjoining producing and transporting operators cannot agree on a transfer point, the BSEE Regional Supervisor and the appropriate Department of Transportation (DOT) pipeline official may jointly determine the transfer point.

(4) The transfer point serves as a regulatory boundary. An operator may request that the BSEE Regional Supervisor grant an exception to this requirement for an individual facility or area. The Regional Supervisor, in consultation with the appropriate DOT pipeline official and affected parties, may grant the request.

(5) Pipeline segments designed, constructed, maintained, and operated under DOT regulations but transferring to DOI regulation as of October 16, 1998, may continue to operate under DOT design and construction requirements until significant modifications or repairs are made to those segments. After October 16, 1998, BSEE operational and maintenance requirements will apply to those segments.

(6) Any producer operating a pipeline that crosses into State waters without first connecting to a transporting operator's facility on the OCS must comply with this subpart. Compliance must extend from the point where hydrocarbons are first produced, through and

including the last valve and associated safety equipment (e.g., pressure safety sensors) on the last production facility on the OCS.

(7) Any producer operating a pipeline that connects facilities on the OCS must comply with this subpart.

(8) Any operator of a pipeline that has a valve on the OCS downstream (landward) of the last production facility may ask in writing that the BSEE Regional Supervisor recognize that valve as the last point BSEE will exercise its regulatory authority.

(9) A pipeline segment is not subject to BSEE regulations for design, construction, operation, and maintenance if:

(i) It is downstream (generally shoreward) of the last valve and associated safety equipment on the last production facility on the OCS; and

(ii) It is subject to regulation under 49 CFR parts 192 and 195.

(10) DOT may inspect all upstream safety equipment (including valves, over-pressure protection devices, cathodic protection equipment, and pigging devices, *etc.*) that serve to protect the integrity of DOT-regulated pipeline segments.

(11) OCS pipeline segments not subject to DOT regulation under 49 CFR parts 192 and 195 are subject to all BSEE regulations.

(12) A producer may request that its pipeline operate under DOT regulations governing pipeline design, construction, operation, and maintenance.

(i) The operator's request must be in the form of a written petition to the BSEE Regional Supervisor that states the justification for the pipeline to operate under DOT regulation.

(ii) The Regional Supervisor will decide, on a case-by-case basis, whether to grant the operator's request. In considering each petition, the Regional Supervisor will consult with the appropriate DOT pipeline official.

(13) A transporter who operates a pipeline regulated by DOT may request to operate under BSEE regulations governing pipeline operation and maintenance. Any subsequent repairs or modifications will also be subject to BSEE regulations governing design and construction.

(i) The operator's request must be in the form of a written petition to the appropriate DOT pipeline official and the BSEE Regional Supervisor.

(ii) The BSEE Regional Supervisor and the appropriate DOT pipeline official will decide how to act on this petition.

(d) A pipeline which qualifies as a right-of-way pipeline (see § 250.1001, 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).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1001 Definitions.

Terms used in this subpart shall have the meanings given below:

DOI pipelines include:

(1) Producer-operated pipelines extending upstream (generally seaward) from each point on the OCS at which operating responsibility transfers from a producing operator to a transporting operator;

(2) Producer-operated pipelines extending upstream (generally seaward) of the last valve (including associated safety equipment) on the last production facility on the OCS that do not

connect to a transporter-operated pipeline on the OCS before crossing into State waters;

(3) Producer-operated pipelines connecting production facilities on the OCS;

(4) Transporter-operated pipelines that DOI and DOT have agreed are to be regulated as DOI pipelines; and

(5) All OCS pipelines not subject to regulation under 49 CFR parts 192 and 195.

DOT pipelines include:

(1) Transporter-operated pipelines currently operated under DOT requirements governing design, construction, maintenance, and operation;

(2) Producer-operated pipelines that DOI and DOT have agreed are to be regulated under DOT requirements governing design, construction, maintenance, and operation; and

(3) Producer-operated pipelines downstream (generally shoreward) of the last valve (including associated safety equipment) on the last production facility on the OCS that do not connect to a transporter-operated pipeline on the OCS before crossing into State waters and that are regulated under 49 CFR parts 192 and 195.

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.

Out-of-service pipelines are those pipelines that have not been used to transport oil, natural gas, sulfur, or produced water for more than 30 consecutive days.

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.)

Production facilities means OCS facilities that receive hydrocarbon production either directly from wells or from other facilities that produce hydrocarbons from wells. They may include processing equipment for treating the production or separating it into its various liquid and gaseous components before transporting it to shore.

Right-of-way pipelines are those pipelines which—

(1) Are contained within the boundaries of a single lease or group of unitized leases but are not owned and operated by the 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) Cross any portion of an unleased block(s).

§ 250.1002 Design requirements for DOI pipelines.

(a) The internal design pressure for steel pipe shall be determined in accordance with the following formula:

$$P = \frac{2(S)(t)}{D} \times (F)(E)(T)$$

For limitations see section 841.121 of American National Standards Institute (ANSI) B31.8 (as incorporated by reference in § 250.198) 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 ANSI/API Spec 6A (as incorporated by reference in § 250.198), ANSI/API Spec 6D (as incorporated by reference in § 250.198), 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/ASME B16.5, ANSI/API Spec 6A, or the equivalent (as incorporated by reference in § 250.198). 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.

(4) If you are installing pipelines constructed of unbonded flexible pipe, you must design them according to the standards and procedures of ANSI/API Spec. 17J, as incorporated by reference in § 250.198.

(5) You must design pipeline risers for tension leg platforms and other floating platforms according to the design standards of API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs) (as incorporated by reference in § 250.198).

(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) pressure 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, you must install and maintain redundant safety devices meeting the requirements of section A9 of API RP 14C (as incorporated by reference in § 250.198). 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.

[76 FR 64462, Oct. 18, 2011, as amended at 83 FR 49263, Sept. 28, 2018]

§ 250.1003 Installation, testing, and repair requirements for DOI pipelines.

(a)(1) Pipelines greater than 8⅝ 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 pressure 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.

§ 250.1004 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 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 must comply with section A7 of API RP 14C (as incorporated by reference in § 250.198). 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.

§ 250.1005 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.

§ 250.1006 How must I decommission and take out of service a DOI pipeline?

(a) The requirements for decommissioning pipelines are listed in § 250.1750 through § 250.1754.

(b) The table in this section lists the requirements if you take a DOI pipeline out of service:

If you have the pipeline out of service for:	Then you must:
(1) 1 year or less,	Isolate the pipeline with a blind flange or a closed block valve at each end of the pipeline.
(2) More than 1 year but less than 5 years,	Flush and fill the pipeline with inhibited seawater.
(3) 5 or more years,	Decommission the pipeline according to §§ 250.1750–250.1754.

§ 250.1007 What to include in applications.

(a) Applications to install a lease term pipeline or for a pipeline right-of-way grant must be submitted in quadruplicate to the Regional Supervisor. Right-of-way grant applications must include an identification of the operator of the pipeline. Each application must 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. The schematic must indicate the point on the OCS at which operating responsibility transfers between a producing operator and a transporting operator.

(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) A description of any additional design precautions you took to enable the pipeline to withstand the effects of water currents, storm or ice scouring, soft bottoms, mudslides, earthquakes, permafrost, and other environmental factors.

(i) If you propose to use unbonded flexible pipe, your application must include:

(A) The manufacturer's design specification sheet;

(B) The design pressure (psi);

(C) An identification of the design standards you used; and

(D) A review by a third-party independent verification agent (IVA) according to ANSI/API Spec. 17J (as incorporated by reference in § 250.198), if applicable.

(ii) If you propose to use one or more pipeline risers for a tension leg platform or other floating platform, your application must include:

(A) The design fatigue life of the riser, with calculations, and the fatigue point at which you would replace the riser;

(B) The results of your vortex-induced vibration (VIV) analysis;

(C) An identification of the design standards you used; and

(D) A description of any necessary mitigation measures such as the use of helical strakes or anchoring devices.

(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.

[76 FR 64462, Oct. 18, 2011, as amended at 83 FR 49263, Sept. 28, 2018]

§ 250.1008 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 must notify the Regional Supervisor before the repair of any pipeline or as soon as practicable. Your notification must be accompanied by payment of the service fee listed in § 250.125. You must submit a detailed report of the repair of a pipeline or pipeline component to the Regional Supervisor within 30 days after the completion of the repairs. In the report you must 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 § 250.1005(b) of this part shall be submitted to the Regional Supervisor by the lessee before March of each year.

§ 250.1009 Requirements to obtain pipeline right-of-way grants.

(a) In addition to applicable requirements of §§ 250.1000 through 250.1008 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.

(b) 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.

§ 250.1010 General requirements for pipeline right-of-way holders.

An applicant, by accepting a right-of-way grant, agrees to comply with the following requirements:

(a) The right-of-way holder shall comply with applicable laws and regulations and the terms of the grant.

(b) 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.

(c) 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 right-of-way holder how to protect it.

(d) 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.

(e) 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.

(f)(1) 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.

(2) Unless otherwise exempted by FERC pursuant to 43 U.S.C. 1334(f)(2), the holder shall:

(i) Provide open and nondiscriminatory access to a right-of-way pipeline to both owner and nonowner shippers, and

(ii) 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.

(g) The area covered by a right-of-way and all improvements thereon shall be kept open at all reasonable times for inspection by the Bureau of Safety and Environmental Enforcement (BSEE). 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.

(h) 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 § 250.1019 of this part.

§ 250.1011 [Reserved]

§ 250.1012 Required payments for pipeline right-of-way holders.

(a) You must pay ONRR, under the regulations at 30 CFR part 1218, an annual rental of $15 for each statute mile, or part of a statute mile, of the OCS that your pipeline right-of-way crosses.

(b) This paragraph applies to you if you obtain a pipeline right-of-way that includes a site for an accessory to the pipeline, including but not limited to a platform. This paragraph also applies if you apply to modify a right-of-way to change the site footprint. In either case, you must pay the amounts shown in the following table.

If . . .	Then . . .
(1) Your accessory site is located in water depths of less than 200 meters;	You must pay ONRR, under the regulations at 30 CFR part 1218, a rental of $5 per acre per year with a minimum of $450 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other facilities and devices associated with the accessory.
(2) Your accessory site is located in water depths of 200 meters or greater;	You must pay ONRR, under the regulations at 30 CFR part 1218, a rental of $7.50 per acre per year with a minimum of $675 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other facilities and devices associated with the accessory.

(c) If you hold a pipeline right-of-way that includes a site for an accessory to your pipeline and you are not covered by paragraph (b) of this section, then you must pay ONRR, under the regulations at 30 CFR part 1218, an annual rental of $75 for use of the affected area.

(d) You may make the rental payments required by paragraphs (a), (b)(1), (b)(2), and (c) of this section on an annual basis, for a 5-year period, or for multiples of 5 years. You must make the first payment at the time you submit the pipeline right-of-way application. You must make all subsequent payments before the respective time periods begin.

(e) *Late payments.* An interest charge will be assessed on unpaid and underpaid amounts from the date the amounts are due, in accordance with the provisions found in 30 CFR 1218.54. If you fail to make a payment that is late after written notice from ONRR, BSEE may initiate cancellation of the right-of-use grant and easement under § 250.1013.

§ 250.1013 Grounds for forfeiture of pipeline right-of-way grants.

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.

§ 250.1014 When pipeline right-of-way grants expire.

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.

§ 250.1015 Applications for pipeline right-of-way grants.

(a) You must submit an original and three copies of an application for a new or modified pipeline ROW grant to the Regional Supervisor. The application must address those items required by § 250.1007(a) or (b) of this subpart, as applicable. It must also state the primary purpose for which you will use the ROW grant. If the ROW has been used before the application is made, the application must state the date such use began, by whom, and the date the applicant obtained control of the improvement. When you file your application, you must pay the rental required under § 250.1012 of this subpart, as well as the service fees listed in § 250.125 of this part for a pipeline ROW grant to install a new pipeline, or to convert an existing lease term pipeline into a ROW pipeline. An application to modify an approved ROW grant must be accompanied by the additional rental required under § 250.1012 if applicable. You must file a separate application for each ROW.

(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 BSEE 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 BSEE (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 BSEE regional office.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1016 Granting pipeline rights-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 § 250.1015(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.

§ 250.1017 Requirements for construction under pipeline right-of-way grants.

(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.

§ 250.1018 Assignment of pipeline right-of-way grants.

(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 must be accompanied by the same showing of qualifications of the assignees as is required of an applicant for a ROW in § 250.1015 of this subpart and must be supported by a statement that the assignee agrees to comply with and to be bound by the terms and conditions of the ROW grant. The assignee must satisfy the bonding requirements in 30 CFR 550.1011. No transfer will be recognized unless and until it is first approved, in writing, by the Regional Supervisor. The assignee must pay the service fee listed in § 250.125 of this part for a pipeline ROW assignment request.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1019 Relinquishment of pipeline right-of-way grants.

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 must contain those items addressed in §§ 250.1751 and 250.1752 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 § 250.1010(h) of this part.

Subpart K—Oil and Gas Production Requirements

GENERAL

§ 250.1150 What are the general reservoir production requirements?

You must produce wells and reservoirs at rates that provide for economic development while maximizing ultimate recovery and without adversely affecting correlative rights.

WELL TESTS AND SURVEYS

§ 250.1151 How often must I conduct well production tests?

(a) You must conduct well production tests as shown in the following table:

You must conduct:	And you must submit to the Regional Supervisor:
(1) A well-flow potential test on all new, recompleted, or reworked well completions within 30 days of the date of first continuous production,	Form BSEE–0126, Well Potential Test Report, along with the supporting data as listed in the table in § 250.1167, within 15 days after the end of the test period.
(2) At least one well test during a calendar half-year for each producing completion,	Results on Form BSEE–0128, Semiannual Well Test Report, of the most recent well test obtained. This must be submitted within 45 days after the end of the calendar half-year.

(b) You may request an extension from the Regional Supervisor if you cannot submit the results of a semiannual well test within the specified time.

(c) You must submit to the Regional Supervisor an original and two copies of the appropriate form required by paragraph (a) of this section; one of the copies of the form must be a public information copy in accordance with §§ 250.186 and 250.197, and marked ''Public Information.'' You must submit two copies of the supporting information as listed in the table in § 250.1167 with form BSEE–0126.

§ 250.1152 How do I conduct well tests?

(a) When you conduct well tests you must:

(1) Recover fluid from the well completion equivalent to the amount of fluid introduced into the formation during completion, recompletion, reworking, or treatment operations before you start a well test;

(2) Produce the well completion under stabilized rate conditions for at least 6 consecutive hours before beginning the test period;

(3) Conduct the test for at least 4 consecutive hours;

(4) Adjust measured gas volumes to the standard conditions of 14.73 pounds per square inch absolute (psia) and 60 °F for all tests; and

(5) Use measured specific gravity values to calculate gas volumes.

(b) You may request approval from the Regional Supervisor to conduct a well test using alternative procedures if you can demonstrate test reliability under those procedures.

(c) The Regional Supervisor may also require you to conduct the following tests and complete them within a specified time period:

(1) A retest or a prolonged test of a well completion if it is determined to be necessary for the proper establishment of a Maximum Production Rate (MPR) or a Maximum Efficient Rate (MER); and

(2) A multipoint back-pressure test to determine the theoretical open-flow potential of a gas well.

(d) A BSEE representative may witness any well test. Upon request, you must provide advance notice to the Regional Supervisor of the times and dates of well tests.

§§ 250.1153–250.1155 [Reserved]

APPROVALS PRIOR TO PRODUCTION

§ 250.1156 What steps must I take to receive approval to produce within 500 feet of a unit or lease line?

(a) You must obtain approval from the Regional Supervisor before you start producing from a reservoir within a well that has any portion of the completed interval less than 500 feet from a unit or lease line. Submit to BSEE the service fee listed in § 250.125, according to the instructions in § 250.126, and the supporting information, as listed in the table in § 250.1167, with your request.

The Regional Supervisor will determine whether approval of your request will maximize ultimate recovery, avoid the waste of natural resources, or protect correlative rights. You do not need to obtain approval if the adjacent leases or units have the same unit, lease (record title and operating rights), and royalty interests as the lease or unit you plan to produce. You do not need to obtain approval if the adjacent block is unleased.

(b) You must notify the operator(s) of adjacent property(ies) that are within 500 feet of the completion, if the adjacent acreage is a leased block in the Federal OCS. You must provide the Regional Supervisor proof of the date of the notification. The operators of the adjacent properties have 30 days after receiving the notification to provide the Regional Supervisor letters of acceptance or objection. If an adjacent operator does not respond within 30 days, the Regional Supervisor will presume there are no objections and proceed with a decision. The notification must include:

(1) The well name;

(2) The rectangular coordinates (x, y) of the location of the top and bottom of the completion or target completion referenced to the North American Datum 1983, and the subsea depths of the top and bottom of the completion or target completion;

(3) The distance from the completion or target completion to the unit or lease line at its nearest point; and

(4) A statement indicating whether or not it will be a high-capacity completion having a perforated or open hole interval greater than 150 feet measured depth.

§ 250.1157 How do I receive approval to produce gas-cap gas from an oil reservoir with an associated gas cap?

(a) You must request and receive approval from the Regional Supervisor:

(1) Before producing gas-cap gas from each completion in an oil reservoir that is known to have an associated gas cap.

(2) To continue production from a well if the oil reservoir is not initially known to have an associated gas cap, but the oil well begins to show characteristics of a gas well.

(b) For either request, you must submit the service fee listed in § 250.125, according to the instructions in § 250.126, and the supporting information, as listed in the table in § 250.1167, with your request.

(c) The Regional Supervisor will determine whether your request maximizes ultimate recovery.

§ 250.1158 How do I receive approval to downhole commingle hydrocarbons?

(a) Before you perforate a well, you must request and receive approval from the Regional Supervisor to commingle hydrocarbons produced from multiple reservoirs within a common wellbore. The Regional Supervisor will determine whether your request maximizes ultimate recovery. You must include the service fee listed in § 250.125, according to the instructions in § 250.126, and the supporting information, as listed in the table in § 250.1167, with your request.

(b) If one or more of the reservoirs proposed for commingling is a competitive reservoir, you must notify the operators of all leases that contain the reservoir that you intend to downhole commingle the reservoirs. Your request for approval of downhole commingling must include proof of the date of this notification. The notified operators have 30 days after notification to provide the Regional Supervisor with letters of acceptance or objection. If the notified operators do not respond within the specified period, the Regional Supervisor will assume the operators do not object and proceed with a decision.

PRODUCTION RATES

§ 250.1159 May the Regional Supervisor limit my well or reservoir production rates?

(a) The Regional Supervisor may set a Maximum Production Rate (MPR) for a producing well completion, or set a Maximum Efficient Rate (MER) for a reservoir, or both, if the Regional Supervisor determines that an excessive production rate could harm ultimate recovery. An MPR or MER will be based on well tests and any limitations

imposed by well and surface equipment, sand production, reservoir sensitivity, gas-oil and water-oil ratios, location of perforated intervals, and prudent operating practices.

(b) If the Regional Supervisor sets an MPR for a producing well completion and/or an MER for a reservoir, you may not exceed those rates except due to normal variations and fluctuations in production rates as set by the Regional Supervisor.

FLARING, VENTING, AND BURNING HYDROCARBONS

§ 250.1160 When may I flare or vent gas?

(a) You must request and receive approval from the Regional Supervisor to flare or vent natural gas at your facility, except in the following situations:

Condition	Additional requirements
(1) When the gas is lease use gas (produced natural gas which is used on or for the benefit of lease operations such as gas used to operate production facilities) or is used as an additive necessary to burn waste products, such as H_2S.	The volume of gas flared or vented may not exceed the amount necessary for its intended purpose. Burning waste products may require approval under other regulations.
(2) During the restart of a facility that was shut in because of weather conditions, such as a hurricane.	Flaring or venting may not exceed 48 cumulative hours without Regional Supervisor approval.
(3) During the blow down of transportation pipelines downstream of the royalty meter.	(i) You must report the location, time, flare/vent volume, and reason for flaring/venting to the Regional Supervisor in writing within 72 hours after the incident is over. (ii) Additional approval may be required under subparts H and J of this part.
(4) During the unloading or cleaning of a well, drill-stem testing, production testing, other well-evaluation testing, or the necessary blow down to perform these procedures.	You may not exceed 48 cumulative hours of flaring or venting per unloading or cleaning or testing operation on a single completion without Regional Supervisor approval.
(5) When properly working equipment yields flash gas (natural gas released from liquid hydrocarbons as a result of a decrease in pressure, an increase in temperature, or both) from storage vessels or other low-pressure production vessels, and you cannot economically recover this flash gas.	You may not flare or vent more than an average of 50 MCF per day during any calendar month without Regional Supervisor approval.
(6) When the equipment works properly but there is a temporary upset condition, such as a hydrate or paraffin plug.	(i) For oil-well gas and gas-well flash gas (natural gas released from condensate as a result of a decrease in pressure, an increase in temperature, or both), you may not exceed 48 continuous hours of flaring or venting without Regional Supervisor approval. (ii) For primary gas-well gas (natural gas from a gas well completion that is at or near its wellhead pressure; this does not include flash gas), you may not exceed 2 continuous hours of flaring or venting without Regional Supervisor approval. (iii) You may not exceed 144 cumulative hours of flaring or venting during a calendar month without Regional Supervisor approval.
(7) When equipment fails to work properly, during equipment maintenance and repair, or when you must relieve system pressures.	(i) For oil-well gas and gas-well flash gas, you may not exceed 48 continuous hours of flaring or venting without Regional Supervisor approval. (ii) For primary gas-well gas, you may not exceed 2 continuous hours of flaring or venting without Regional Supervisor approval. (iii) You may not exceed 144 cumulative hours of flaring or venting during a calendar month without Regional Supervisor approval. (iv) The continuous and cumulative hours allowed under this paragraph may be counted separately from the hours under paragraph (a)(6) of this section.

(b) Regardless of the requirements in paragraph (a) of this section, you must not flare or vent gas over the volume approved in your Development Operations Coordination Document (DOCD) or your Development and Production Plan (DPP) submitted to BOEM.

(c) The Regional Supervisor may establish alternative approval procedures to cover situations when you cannot contact the BSEE office, such as during non-office hours.

(d) The Regional Supervisor may specify a volume limit, or a shorter time limit than specified elsewhere in this part, in order to prevent air quality degradation or loss of reserves.

(e) If you flare or vent gas without the required approval, or if the Regional Supervisor determines that you were negligent or could have avoided flaring or venting the gas, the hydrocarbons will be considered avoidably lost or wasted. You must pay royalties on the loss or waste, according to 30 CFR part 1202. You must value any gas or liquid hydrocarbons avoidably lost or wasted under the provisions of 30 CFR part 1206.

(f) Fugitive emissions from valves, fittings, flanges, pressure relief valves or similar components do not require approval under this subpart unless specifically required by the Regional Supervisor.

§ 250.1161 When may I flare or vent gas for extended periods of time?

You must request and receive approval from the Regional Supervisor to flare or vent gas for an extended period of time. The Regional Supervisor will specify the approved period of time, which will not exceed 1 year. The Regional Supervisor may deny your request if it does not ensure the conservation of natural resources or is not consistent with National interests relating to development and production of minerals of the OCS. The Regional Supervisor may approve your request for one of the following reasons:

(a) You initiated an action which, when completed, will eliminate flaring and venting; or

(b) You submit to the Regional Supervisor an evaluation supported by engineering, geologic, and economic data indicating that the oil and gas produced from the well(s) will not economically support the facilities necessary to sell the gas or to use the gas on or for the benefit of the lease.

§ 250.1162 When may I burn produced liquid hydrocarbons?

(a) You must request and receive approval from the Regional Supervisor to burn any produced liquid hydrocarbons. The Regional Supervisor may allow you to burn liquid hydrocarbons if you demonstrate that transporting them to market or re-injecting them is not technically feasible or poses a significant risk of harm to offshore personnel or the environment.

(b) If you burn liquid hydrocarbons without the required approval, or if the Regional Supervisor determines that you were negligent or could have avoided burning liquid hydrocarbons, the hydrocarbons will be considered avoidably lost or wasted. You must pay royalties on the loss or waste, according to 30 CFR part 1202. You must value any liquid hydrocarbons avoidably lost or wasted under the provisions of 30 CFR part 1206.

§ 250.1163 How must I measure gas flaring or venting volumes and liquid hydrocarbon burning volumes, and what records must I maintain?

(a) If your facility processes more than an average of 2,000 bopd during May 2010, you must install flare/vent meters within 180 days after May 2010. If your facility processes more than an average of 2,000 bopd during a calendar month after May 2010, you must install flare/vent meters within 120 days after the end of the month in which the average amount of oil processed exceeds 2,000 bopd.

(1) You must notify the Regional Supervisor when your facility begins to process more than an average of 2,000 bopd in a calendar month;

(2) The flare/vent meters must measure all flared and vented gas within 5 percent accuracy;

(3) You must calibrate the meters regularly, in accordance with the manufacturer's recommendation, or at least once every year, whichever is shorter; and

(4) You must use and maintain the flare/vent meters for the life of the facility.

(b) You must report all hydrocarbons produced from a well completion, including all gas flared, gas vented, and liquid hydrocarbons burned, to Office of Natural Resources Revenue on Form ONRR–4054 (Oil and Gas Operations Report), in accordance with 30 CFR 1210.102.

(1) You must report the amount of gas flared and the amount of gas vented separately.

(2) You may classify and report gas used to operate equipment on the lease, such as gas used to power engines, instrument gas, and gas used to maintain pilot lights, as lease use gas.

(3) If flare/vent meters are required at one or more of your facilities, you must report the amount of gas flared and vented at each of those facilities separately from those facilities that do not require meters and separately from other facilities with meters.

(4) If flare/vent meters are not required at your facility:

(i) You may report the gas flared and vented on a lease or unit basis. Gas flared and vented from multiple facilities on a single lease or unit may be reported together.

(ii) If you choose to install meters, you may report the gas volume flared and vented according to the method specified in paragraph (b)(3) of this section.

(c) You must prepare and maintain records detailing gas flaring, gas venting, and liquid hydrocarbon burning for each facility for 6 years.

(1) You must maintain these records on the facility for at least the first 2 years and have them available for inspection by BSEE representatives.

(2) After 2 years, you must maintain the records, allow BSEE representatives to inspect the records upon request and provide copies to the Regional Supervisor upon request, but are not required to keep them on the facility.

(3) The records must include, at a minimum:

(i) Daily volumes of gas flared, gas vented, and liquid hydrocarbons burned;

(ii) Number of hours of gas flaring, gas venting, and liquid hydrocarbon burning, on a daily and monthly cumulative basis;

(iii) A list of the wells contributing to gas flaring, gas venting, and liquid hydrocarbon burning, along with gas-oil ratio data;

(iv) Reasons for gas flaring, gas venting, and liquid hydrocarbon burning; and

(v) Documentation of all required approvals.

(d) If your facility is required to have flare/vent meters:

(1) You must maintain the meter recordings for 6 years.

(i) You must keep these recordings on the facility for 2 years and have them available for inspection by BSEE representatives.

(ii) After 2 years, you must maintain the recordings, allow BSEE representatives to inspect the recordings upon request and provide copies to the Regional Supervisor upon request, but are not required to keep them on the facility.

(iii) These recordings must include the begin times, end times, and volumes for all flaring and venting incidents.

(2) You must maintain flare/vent meter calibration and maintenance records on the facility for 2 years.

(e) If your flaring or venting of gas, or burning of liquid hydrocarbons, required written or oral approval, you must submit documentation to the Regional Supervisor summarizing the location, dates, number of hours, and volumes of gas flared, gas vented, and liquid hydrocarbons burned under the approval.

§ 250.1164 What are the requirements for flaring or venting gas containing H_2S?

(a) You may 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 atmosphere concentration of H_2S of 20 ppm or higher anywhere on the platform.

(b) You may flare gas containing H_2S only if you meet the requirements of §§ 250.1160, 250.1161, 250.1163, and the following additional requirements:

(1) For safety or air pollution prevention purposes, the Regional Supervisor may further restrict the flaring of gas containing H_2S. The Regional Supervisor will use information provided in the lessee's H_2S Contingency Plan (§ 250.490(f)), Exploration Plan, DPP, DOCD submitted to BOEM, and associated documents to determine the need for restrictions; and

(2) 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 you to conduct an air quality modeling analysis, under 30 CFR 550.303, to determine the potential effect of facility emissions. The Regional Supervisor

may require monitoring and reporting, or may restrict or prohibit flaring, under 30 CFR 550.303 and 30 CFR 550.304.

(c) The Regional Supervisor may require you to submit monthly reports of flared and vented gas containing H_2S. Each report must contain, on a daily basis:

(1) The volume and duration of each flaring and venting occurrence;

(2) H_2S concentration in the flared or vented gas; and

(3) The calculated amount of SO_2 emitted.

OTHER REQUIREMENTS

§ 250.1165 What must I do for enhanced recovery operations?

(a) You must promptly initiate enhanced oil and gas recovery operations for all reservoirs where these operations would result in an increase in ultimate recovery of oil or gas under sound engineering and economic principles.

(b) Before initiating enhanced recovery operations, you must submit a proposed plan to the BSEE Regional Supervisor and receive approval for pressure maintenance, secondary or tertiary recovery, cycling, and similar recovery operations intended to increase the ultimate recovery of oil and gas from a reservoir. The proposed plan must include, for each project reservoir, a geologic and engineering overview and any additional information required by the BSEE Regional Supervisor. You also must submit Form BOEM–0127 to BOEM along with the supporting data specified in BOEM regulations, 30 CFR part 550, subpart K.

(c) You must report to Office of Natural Resources Revenue the volumes of oil, gas, or other substances injected, produced, or produced for a second time under 30 CFR 1210.102.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1166 What additional reporting is required for developments in the Alaska OCS Region?

(a) For any development in the Alaska OCS Region, you must submit an annual reservoir management report to the Regional Supervisor. The report must contain information detailing the activities performed during the previous year and planned for the upcoming year that will:

(1) Provide for the prevention of waste;

(2) Provide for the protection of correlative rights; and

(3) Maximize ultimate recovery of oil and gas.

(b) If your development is jointly regulated by BSEE and the State of Alaska, BSEE and the Alaska Oil and Gas Conservation Commission will jointly determine appropriate reporting requirements to minimize or eliminate duplicate reporting requirements.

(c) [Reserved]

§ 250.1167 What information must I submit with forms and for approvals?

You must submit the supporting information listed in the following table with the form identified in column 1 and for the approvals required under this subpart identified in columns 2 through 4:

	WPT BSEE–0126 (2 copies)	Gas cap production	Downhole commingling	Production within 500-ft of a unit or lease line
(a) Maps:				
(1) Base map with surface, bottomhole, and completion locations with respect to the unit or lease line and the orientation of representative seismic lines or cross-sections	.....	✔	✔	✔
(2) Structure maps with penetration point and subsea depth for each well penetrating the reservoirs, highlighting subject wells; reservoir boundaries; and original and current fluid levels	✔	✔	✔	✔
(3) Net sand isopach with total net sand penetrated for each well, identified at the penetration point	.....	✔	✔	
(4) Net hydrocarbon isopach with net feet of pay for each well, identified at the penetration point	.....	✔	✔	
(b) Seismic data:				

	WPT BSEE–0126 (2 copies)	Gas cap production	Downhole commingling	Production within 500-ft of a unit or lease line
(1) Representative seismic lines, including strike and dip lines that confirm the structure; indicate polarity		✔	✔	✔
(2) Amplitude extraction of seismic horizon, if applicable		✔	✔	✔
(c) Logs:				
(1) Well log sections with tops and bottoms of the reservoir(s) and proposed or existing perforations	✔	✔	✔	✔
(2) Structural cross-sections showing the subject well and nearby wells		✔	✔	*
(d) Engineering data:				
(1) Estimated recoverable reserves for each well completion in the reservoir; total recoverable reserves for each reservoir; method of calculation; reservoir parameters used in volumetric and decline curve analysis		†	†	✔
(2) Well schematics showing current and proposed conditions		✔	✔	✔
(3) The drive mechanism of each reservoir		✔	✔	✔
(4) Pressure data, by date, and whether they are estimated or measured		✔	✔	
(5) Production data and decline curve analysis indicative of the reservoir performance		✔	✔	
(6) Reservoir simulation with the reservoir parameters used, history matches, and prediction runs (include proposed development scenario)		*	*	*
(e) General information:				
(1) Detailed economic analysis		*	*	
(2) Reservoir name and whether or not it is competitive as defined under § 250.105		✔	✔	✔
(3) Operator name, lessee name(s), block, lease number, royalty rate, and unit number (if applicable) of all relevant leases		✔	✔	✔
(4) Geologic overview of project		✔	✔	✔
(5) Explanation of why the proposed completion scenario will maximize ultimate recovery		✔	✔	✔
(6) List of all wells in subject reservoirs that have ever produced or been used for injection		✔	✔	✔

✔ Required.
† Each Gas Cap Production request and Downhole Commingling request must include the estimated recoverable reserves for (1) the case where your proposed production scenario is approved, and (2) the case where your proposed production scenario is denied.
* Additional items the Regional Supervisor may request.
Note: All maps must be at a standard scale and show lease and unit lines. The Regional Supervisor may waive submittal of some of the required data on a case-by-case basis.

(f) Depending on the type of approval requested, you must submit the appropriate payment of the service fee(s) listed in § 250.125, according to the instructions in § 250.126.

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

§ 250.1200 Question index table.

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

Frequently asked questions	CFR citation
1. What are the requirements for measuring liquid hydrocarbons?	§ 250.1202(a)
2. What are the requirements for liquid hydrocarbon royalty meters?	§ 250.1202(b)
3. What are the requirements for run tickets?	§ 250.1202(c)
4. What are the requirements for liquid hydrocarbon royalty meter provings?	§ 250.1202(d)
5. What are the requirements for calibrating a master meter used in royalty meter provings?	§ 250.1202(e)
6. What are the requirements for calibrating mechanical-displacement provers and tank provers?	§ 250.1202(f)

Frequently asked questions	CFR citation
7. What correction factors must a lessee use when proving meters with a mechanical displacement prover, tank prover, or master meter?	§ 250.1202(g)
8. What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?	§ 250.1202(h)
9. Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must a lessee do?	§ 250.1202(i)
10. How must a lessee correct gross liquid hydrocarbon volumes to standard conditions?	§ 250.1202(j)
11. What are the requirements for liquid hydrocarbon allocation meters?	§ 250.1202(k)
12. What are the requirements for royalty and inventory tank facilities?	§ 250.1202(l)
13. To which meters do BSEE requirements for gas measurement apply?	§ 250.1203(a)
14. What are the requirements for measuring gas?	§ 250.1203(b)
15. What are the requirements for gas meter calibrations?	§ 250.1203(c)
16. What must a lessee do if a gas meter is out of calibration or malfunctioning?	§ 250.1203(d)
17. What are the requirements when natural gas from a Federal lease is transferred to a gas plant before royalty determination?	§ 250.1203(e)
18. What are the requirements for measuring gas lost or used on a lease?	§ 250.1203(f)
19. What are the requirements for the surface commingling of production?	§ 250.1204(a)
20. What are the requirements for a periodic well test used for allocation?	§ 250.1204(b)
21. What are the requirements for site security?	§ 250.1205(a)
22. What are the requirements for using seals?	§ 250.1205(b)

§ 250.1201 Definitions.

Terms not defined in this section have the meanings given in the applicable chapter of the API MPMS, which is incorporated by reference in § 250.198. Terms used in Subpart L have the following meaning:

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

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

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

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

Force majeure event—an event beyond your control such as war, act of terrorism, crime, or act of nature which prevents you from operating the wells and meters on your OCS facility.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Surface commingling—the surface mixing of production from two or more leases and/or unit participating areas prior to royalty measurement.

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

Verification/Calibration—testing and correcting, if necessary, a measuring device to ensure compliance with industry accepted, manufacturer's recommended, or regulatory required standard of accuracy.

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

§ 250.1202 Liquid hydrocarbon measurement.

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

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing liquid hydrocarbon production, or making any changes to the previously-approved measurement and/or allocation procedures. Your application (which may also include any relevant gas measurement and surface commingling requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity as shown in the following table.

Application type	Actions
(i) Simple applications,	Applications to temporarily reroute production (for a duration not to exceed six months); Production tests prior to pipeline construction; Departures related to meter proving, well testing, or sampling frequency.
(ii) Complex applications,	Creation of new facility measurement points (FMPs); Association of leases or units with existing FMPs; Inclusion of production from additional structures; Meter updates which add buyback gas meters or pigging meters; Other applications which request deviations from the approved allocation procedures.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) A meter equipped with a nonreset totalizer;

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

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

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

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

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

(i) Prevent flow reversal through the meter;

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

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

(iv) Prevent meter bypassing.

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

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

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

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

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

(i) The sampling point is in the flowstream immediately upstream or downstream of the meter or divert valve in accordance with the API MPMS (as incorporated by reference in § 250.198);

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

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

probe according to the manufacturer's instructions.

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

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

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

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

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

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

(1) Permit BSEE representatives to witness provings;

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

(3) Prove each operating royalty meter to determine the meter factor monthly, but the time between meter factor determinations must not exceed 42 days. When a force majeure event precludes the required monthly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved monthly thereafter, but the time between meter factor determinations must not exceed 42 days;

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

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

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

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

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

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

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

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

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

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

(1) Calibrate mechanical-displacement provers and tank provers at least once every 5 years according to the API MPMS as incorporated by reference in 30 CFR 250.198, including the following additional editions:

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

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

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

(g) *What correction factors must I use when proving meters with a mechanical-displacement prover, tank prover, or master meter?* Calculate the following correction factors using the API MPMS as referenced in 30 CFR 250.198, including the following additional editions:

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

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

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

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

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

(2) If you use a master meter, you must record proof runs until three consecutive runs produce a total meter factor difference of no greater than 0.0005. The flow rate through the meters during the proving must be within 10 percent of the rate at which the line meter will operate. The final meter factor is determined by averaging the meter factors of the three runs;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Take samples continuously proportional to flow or daily (use the procedure in the applicable chapter of the API MPMS as incorporated by reference in § 250.198;

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

(3) Prove operating allocation meters monthly if they measure 50 or more barrels per day per meter the previous month. When a force majeure event precludes the required monthly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved monthly thereafter; or

(4) Prove operating allocation meters quarterly if they measure less than 50 barrels per day per meter the previous month. When a force majeure event precludes the required quarterly meter proving, meters must be proved within 15 days after being returned to service.

The meters must be proved quarterly thereafter;

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

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

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

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

(9) Permit BSEE representatives to witness provings.

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

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

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

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

(4) Obtain the volume and other measurement parameters by using corrections factors and procedures in the API MPMS as incorporated by reference in 30 CFR 250.198, including: API MPMS Chapter 11, Section 1 (incorporated by reference as specified in § 250.198).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 18921, Mar. 29, 2012]

§ 250.1203 Gas measurement.

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

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

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing gas production, or making any changes to the previously-approved measurement and/or allocation procedures. Your application (which may also include any relevant liquid hydrocarbon measurement and surface commingling requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity, see table in § 250.1202(a)(1).

(2) Design, install, use, maintain, and test measurement equipment and procedures to ensure accurate and verifiable measurement. You must follow the recommendations in API MPMS or RP and AGA as incorporated by reference in 30 CFR 250.198, including the following additional editions:

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

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

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

(iv) AGA Report No. 10 (incorporated by reference as specified in § 250.198);

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

(4) Equip the meter with a chart or electronic data recorder. If an electronic data recorder is used, you must follow the recommendations in API MPMS(incorporated by reference as specified in § 250.198).

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

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

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

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

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

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

(1) Verify/calibrate operating meters monthly, but do not exceed 42 days between verifications/calibrations. When a force majeure event precludes the required monthly meter verification/calibration, meters must be verified/calibrated within 15 days after being returned to service. The meters must be verified/calibrated monthly thereafter, but do not exceed 42 days between meter verifications/calibrations;

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

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

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

(5) Permit BSEE representatives to witness calibrations.

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

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

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

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

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

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

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

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

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

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

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

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

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

(4) You must keep the documentation, including the volume data, easily obtainable for inspection at the field location for at least 2 years, and must retain the documentation at a location of your choosing for at least 7 years after the documentation is generated, subject to all other document retention and production requirements in 30 U.S.C. 1713 and 30 CFR part 1212.

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

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 18922, Mar. 29, 2012; 85 FR 84237, Dec. 28, 2020]

§ 250.1204 Surface commingling.

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

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing the commingling of production or making any changes to the previously approved commingling procedures. Your application (which may also include any relevant liquid hydrocarbon and gas measurement requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity, see table in § 250.1202(a)(1).

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

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

(1) Conduct a well test at least once every 60 days unless the Regional Supervisor approves a different frequency. When a force majeure event precludes the required well test within the prescribed 60 day period (or other frequency approved by the Regional Supervisor), wells must be tested within 15 days after being returned to production. Thereafter, well tests must be conducted at least once every 60 days (or other frequency approved by the Regional Supervisor);

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

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

§ 250.1205 Site security.

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

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

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

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

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

(i) Theft or mishandling of production;

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

(iii) Falsifying production measurements.

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

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

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

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

(iii) Temperature and gravity compensation device components;

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

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

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

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

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

Subpart M—Unitization

§ 250.1300 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.

§ 250.1301 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 of a reasonably delineated and productive reservoir if unitized operations are necessary to:

(1) Prevent waste;

(2) Conserve natural resources; or

(3) Protect correlative rights, including Federal royalty interests.

(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 common to two or more leases. 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 (§ 250.180) under the unit agreement, unless the Regional Supervisor orders or approves a suspension of production under § 250.170.

(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) BSEE 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 § 250.180, the unit operator must request and obtain BSEE approval of a suspension of production under § 250.170 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) BSEE orders or approves a suspension of operations under § 250.170.

§ 250.1302 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 Competitive Reservoir Development Program submitted to BSEE 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 BSEE Regional Supervisor, you and the other affected lessees must submit for approval a joint Competitive Reservoir Development Program. You must submit the joint Competitive Reservoir Development Program within 90 days after the Regional Supervisor makes a final determination that the reservoir is competitive. The joint Competitive Reservoir Development Program must provide for the development and/or production of the reservoir. You may submit supplemental Competitive Reservoir Development Programs for the Regional Supervisor's approval.

(d) If you and the other affected lessees cannot reach an agreement on a joint Competitive Reservoir Development Program, submitted to BSEE within the approved period of time, each lessee must submit a separate Competitive Reservoir Development Program to the Regional Supervisor. The Regional Supervisor will hold a hearing to resolve differences in the separate Competitive Reservoir Development Programs. If the differences in the separate programs are not resolved at the hearing and the Regional Supervisor determines that unitization is necessary under § 250.1301(b), BSEE will initiate unitization under § 250.1304.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1303 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 § 250.1300.

(b) The unit agreement must comply with the requirements of this part. BSEE will maintain and provide a model unit agreement for you to follow. If BSEE revises the model, BSEE 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.

(d) You must pay the service fee listed in § 250.125 of this part with your request for a voluntary unitization proposal or the expansion of a previously approved voluntary unit to include additional acreage. Additionally, you must pay the service fee listed in § 250.125 with your request for unitization revision.

§ 250.1304 How will BSEE 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 BSEE to require unitization, you must file a request with the Regional Supervisor. You must include a proposed unit agreement as described in §§ 250.1301(d) and 250.1303(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 § 250.1300. 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, BSEE 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 BSEE provides all lessees of the proposed unit area written notice and an opportunity for a hearing. If you want BSEE 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) BSEE will not hold a hearing under this paragraph until at least 30 days after BSEE 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—Outer Continental Shelf Civil Penalties

OUTER CONTINENTAL SHELF LANDS ACT CIVIL PENALTIES

§ 250.1400 How does BSEE begin the civil penalty process?

This subpart explains BSEEs civil penalty procedures whenever a lessee, operator or other person engaged in oil, gas, sulphur or other minerals operations in the OCS has a violation. Whenever BSEE determines, on the basis of available evidence, that a violation occurred and a civil penalty review is appropriate, it will prepare a case file. BSEE will appoint a Reviewing Officer.

§ 250.1401 [Reserved]

§ 250.1402 Definitions.

Terms used in this subpart have the following meaning:

Case file means a BSEE document file containing information and the record of evidence related to the alleged violation.

Civil penalty means a fine. It is a BSEE regulatory enforcement tool used in addition to Notices of Incidents of Noncompliance and directed suspensions of production or other operations.

Reviewing Officer means a BSEE employee assigned to review case files and assess civil penalties.

Violation means failure to comply with the Outer Continental Shelf Lands Act (OCSLA) or any other applicable laws, with any regulations issued under the OCSLA, or with the terms or provisions of leases, licenses, permits, rights-of-way, or other approvals issued under the OCSLA.

Violator means a person responsible for a violation.

§ 250.1403 What is the maximum civil penalty?

The maximum civil penalty is $48,862 per day per violation.

[87 FR 10308, Feb. 24, 2022]

§ 250.1404 Which violations will BSEE review for potential civil penalties?

BSEE will review each of the following violations for potential civil penalties:

(a) Violations that you do not correct within the period BSEE grants;

(b) Violations that BSEE determines may constitute, 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; or

(c) Violations that cause 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.

(d) Violations of the oil spill financial responsibility requirements at 30 CFR part 553.

§ 250.1405 When is a case file developed?

BSEE will develop a case file during its investigation of the violation, and forward it to a Reviewing Officer if any of the conditions in § 250.1404 exist. The Reviewing Officer will review the case file and determine if a civil penalty is appropriate. The Reviewing Officer may administer oaths and issue subpoenas requiring witnesses to attend meetings, submit depositions, or produce evidence.

§ 250.1406 When will BSEE notify me and provide penalty information?

If the Reviewing Officer determines that a civil penalty should be assessed, the Reviewing Officer will send the violator a letter of notification. The letter of notification will include:

(a) The amount of the proposed civil penalty;

(b) Information on the violation(s); and

(c) Instruction on how to obtain a copy of the case file, schedule a meeting, submit information, or pay the penalty.

§ 250.1407 How do I respond to the letter of notification?

You have 30 calendar days after you receive the Reviewing Officer's letter to either:

(a) Request, in writing, a meeting with the Reviewing Officer;

(b) Submit additional information; or

(c) Pay the proposed civil penalty.

§ 250.1408 When will I be notified of the Reviewing Officer's decision?

At the end of the 30 calendar days or after the meeting and submittal of additional information, the Reviewing Officer will review the case file, including all information you submitted, and send you a decision. The decision will include the amount of any final civil penalty, the basis for the civil penalty, and instructions for paying or appealing the civil penalty.

§ 250.1409 What are my appeal rights?

(a) When you receive the Reviewing Officer's final decision, you have 60 days to either pay the penalty or file an appeal in accordance with 30 CFR part 290, subpart A.

(b) If you file an appeal, you must either:

(1) Submit a surety bond in the amount of the penalty to the appropriate Leasing Office in the Region where the penalty was assessed, following instructions that the Reviewing Officer will include in the final decision; or

(2) Notify the appropriate Leasing Office, in the Region where the penalty was assessed, that you want your lease-specific/area-wide bond on file to be used as the bond for the penalty amount.

(c) If you choose the alternative in paragraph (b)(2) of this section, the BOEM Regional Director may require additional security (*i.e.*, security in excess of your existing bond) to ensure sufficient coverage during an appeal. In that event, the Regional Director will require you to post the supplemental bond with the regional office in the same manner as under 30 CFR 556.53(d) through (f). If the Regional Director determines the appeal should be covered by a lease-specific abandonment account then you must establish an account that meets the requirements of 30 CFR part 556.56.

(d) If you do not either pay the penalty or file a timely appeal, BSEE will take one or more of the following actions:

(1) We will collect the amount you were assessed, plus interest, late payment charges, and other fees as provided by law, from the date you received the Reviewing Officer's final decision until the date we receive payment;

(2) We may initiate additional enforcement, including, if appropriate, cancellation of the lease, right-of-way, license, permit, or approval, or the forfeiture of a bond under this part; or

(3) We may bar you from doing further business with the Federal Government according to Executive Orders 12549 and 12689, and section 2455 of the Federal Acquisition Streamlining Act of 1994, 31 U.S.C. 6101. The Department of the Interior's regulations implementing these authorities are found at 43 CFR part 12, subpart D.

FEDERAL OIL AND GAS ROYALTY MANAGEMENT ACT CIVIL PENALTIES DEFINITIONS

§ 250.1450 What definitions apply to this subpart?

The terms used in this subpart have the same meaning as in 30 U.S.C. 1702.

PENALTIES AFTER A PERIOD TO CORRECT

§ 250.1451 What may BSEE do if I violate a statute, regulation, order, or lease term relating to a Federal oil and gas lease?

(a) If we believe that you have not followed any requirement of a statute, regulation, order, or lease term for any Federal oil or gas lease, we may send you a Notice of Noncompliance informing you what the violation is and what you need to do to correct it to avoid civil penalties under 30 U.S.C. 1719(a) and (b).

(b) We will serve the Notice of Noncompliance by registered mail or personal service using the most current address on file as maintained by the BOEM Leasing Office in your respective Region.

§ 250.1452 What if I correct the violation?

The matter will be closed if you correct all of the violations identified in the Notice of Noncompliance within 20 days after you receive the Notice (or within a longer time period specified in the Notice).

§ 250.1453 What if I do not correct the violation?

(a) We may send you a Notice of Civil Penalty if you do not correct all of the violations identified in the Notice of Noncompliance within 20 days after you receive the Notice of Noncompliance (or within a longer time period specified in that Notice). The Notice of Civil Penalty will tell you how much penalty you must pay for each day, beginning with the date of the Notice of Noncompliance, for each violation identified in the Notice of Noncompliance for as long as you do not correct the violation. The maximum civil penalty amount for each day of such an uncorrected violation is as specified in 30 CFR 1241.52(a)(2).

(b) If you do not correct all of the violations identified in the Notice of Noncompliance within 40 days after you receive the Notice of Noncompliance (or 20 days following the expiration of a longer time period specified in that Notice), we may increase the penalty for each day, beginning with the date of the Notice of Noncompliance, for each violation for as long as you do not correct the violations. The maximum civil penalty amount for each day of such an uncorrected violation is as specified in 30 CFR 1241.52(b).

[86 FR 34134, June 29, 2021]

§ 250.1454 How may I request a hearing on the record on a Notice of Noncompliance?

You may request a hearing on the record on a Notice of Noncompliance by filing a request within 30 days of the date you received the Notice of Noncompliance with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy Street, Arlington, Virginia 22203. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

§ 250.1455 Does my request for a hearing on the record affect the penalties?

(a) If you do not correct the violations identified in the Notice of Noncompliance, the penalties will continue to accrue even if you request a hearing on the record.

(b) You may petition the Hearings Division (Departmental) of the Office of Hearings and Appeals, to stay the accrual of penalties pending the hearing on the record and a decision by the Administrative Law Judge under § 250.1472.

(1) You must file your petition within 45 calendar days of receiving the Notice of Noncompliance.

(2) To stay the accrual of penalties, you must post a bond or other surety instrument, or demonstrate financial solvency, using the standards and requirements as prescribed in BOEM's regulations, 30 CFR part 550, subpart N. The posted amount must cover the unpaid principal and interest due for the Notice of Noncompliance, plus the amount of any penalties accrued before the date a stay becomes effective.

(3) The Hearings Division will grant or deny the petition under 43 CFR 4.21(b).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1456 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

(a) You may request a hearing on the record to challenge only the amount of a civil penalty when you receive a Notice of Civil Penalty, if you did not previously request a hearing on the record under § 250.1454. If you did not request a hearing on the record on the Notice of Noncompliance under § 250.1454, you may not contest your underlying liability for civil penalties.

(b) You must file your request within 10 days after you receive the Notice of Civil Penalty with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy Street, Arlington, Virginia 22203.

PENALTIES WITHOUT A PERIOD TO CORRECT

§ 250.1460 May I be subject to penalties without prior notice and an opportunity to correct?

The Federal Oil and Gas Royalty Management Act sets out several specific violations for which penalties accrue without an opportunity to first correct the violation.

(a) Under 30 U.S.C. 1719(c), you may be subject to civil penalties up to the maximum amount specified in 30 CFR 1241.60(b)(1) for each violation for each day that it continues if you:

(1) Fail or refuse to permit lawful entry, inspection, or audit; or

(2) Knowingly or willfully fail or refuse to notify the Secretary, within 5 business days after any well begins production on a lease site or allocated to a lease site, or resumes production in the case of a well which has been off production for more than 90 days, of the date on which production has begun or resumed.

(b) Under 30 U.S.C. 1719(d), you may be subject to civil penalties up to the maximum amount specified in 30 CFR 1241.60(b)(2) for each violation for each day that it continues if you:

(1) Knowingly or willfully prepare, maintain, or submit false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information;

(2) Knowingly or willfully take or remove, transport, use or divert any oil or gas from any lease site without having valid legal authority to do so; or

(3) Purchase, accept, sell, transport, or convey to another person, any oil or gas knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted.

[86 FR 34134, June 29, 2021]

§ 250.1461 How will BSEE inform me of violations without a period to correct?

We will inform you of any violation, without a period to correct, by issuing a Notice of Noncompliance and Civil Penalty explaining the violation, how to correct it, and the penalty assessment. We will serve the Notice of Noncompliance and Civil Penalty by registered mail or personal service using

your address of record as specified under 30 CFR part 1218, Subpart H.

§ 250.1462 How may I request a hearing on the record on a Notice of Noncompliance regarding violations without a period to correct?

You may request a hearing on the record of a Notice of Noncompliance regarding violations without a period to correct by filing a request within 30 days after you receive the Notice of Noncompliance with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy Street, Arlington, Virginia 22203. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

§ 250.1463 Does my request for a hearing on the record affect the penalties?

(a) If you do not correct the violations identified in the Notice of Noncompliance regarding violations without a period to correct, the penalties will continue to accrue even if you request a hearing on the record.

(b) You may ask the Hearings Division (Departmental) to stay the accrual of penalties pending the hearing on the record and a decision by the Administrative Law Judge under § 250.1472.

(1) You must file your petition within 45 calendar days after you receive the Notice of Noncompliance.

(2) To stay the accrual of penalties, you must post a bond or other surety instrument, or demonstrate financial solvency, using the standards and requirements as prescribed in BOEM's regulations, 30 CFR part 550, subpart N. The posted amount must cover the unpaid principal and interest due for the Notice of Noncompliance, plus the amount of any penalties accrued before the date a stay becomes effective.

(3) The Hearings Division will grant or deny the petition under 43 CFR 4.21(b).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

§ 250.1464 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

(a) You may request a hearing on the record to challenge only the amount of a civil penalty when you receive a Notice of Civil Penalty regarding violations without a period to correct, if you did not previously request a hearing on the record under § 250.1462. If you did not request a hearing on the record on the Notice of Noncompliance under § 250.1462, you may not contest your underlying liability for civil penalties.

(b) You must file your request within 10 days after you receive Notice of Civil Penalty with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy, Arlington, Virginia 22203.

General Provisions

§ 250.1470 How does BSEE decide what the amount of the penalty should be?

We determine the amount of the penalty by considering the severity of the violations, your history of compliance, and if you are a small business.

§ 250.1471 Does the penalty affect whether I owe interest?

If you do not pay the penalty by the date required under § 250.1475(d), BSEE will assess you late payment interest on the penalty amount at the same rate interest is assessed under 30 CFR 1218.54.

§ 250.1472 How will the Office of Hearings and Appeals conduct the hearing on the record?

If you request a hearing on the record under §§ 250.1454, 250.1456, 250.1462, or 250.1464, the hearing will be conducted by a Departmental Administrative Law Judge from the Office of Hearings and Appeals. After the hearing, the Administrative Law Judge will issue a decision in accordance with the evidence presented and applicable law.

§ 250.1473 How may I appeal the Administrative Law Judge's decision?

If you are adversely affected by the Administrative Law Judge's decision,

you may appeal that decision to the Interior Board of Land Appeals under 43 CFR part 4, subpart E.

§ 250.1474 May I seek judicial review of the decision of the Interior Board of Land Appeals?

Under 30 U.S.C. 1719(j), you may seek judicial review of the decision of the Interior Board of Land Appeals. A suit for judicial review in the District Court will be barred unless filed within 90 days after the final order.

§ 250.1475 When must I pay the penalty?

(a) You must pay the amount of the Notice of Civil Penalty issued under § 250.1453 or § 250.1461, if you do not request a hearing on the record under § 250.1454, § 250.1456, § 250.1462, or § 250.1464.

(b) If you request a hearing on the record under § 250.1454, § 250.1456, § 250.1462, or § 250.1464, but you do not appeal the determination of the Administrative Law Judge to the Interior Board of Land Appeals under § 250.1473, you must pay the amount assessed by the Administrative Law Judge.

(c) If you appeal the determination of the Administrative Law Judge to the Interior Board of Land Appeals, you must pay the amount assessed in the IBLA decision.

(d) You must pay the penalty assessed within 40 days after:

(1) You received the Notice of Civil Penalty, if you did not request a hearing on the record under either § 250.1454, § 250.1456, § 250.1462, or § 250.1464;

(2) You received an Administrative Law Judge's decision under § 250.1472, if you obtained a stay of the accrual of penalties pending the hearing on the record under § 250.1455(b) or § 250.1463(b) and did not appeal the Administrative Law Judge's determination to the IBLA under § 250.1473;

(3) You received an IBLA decision under § 250.1473 if the IBLA continued the stay of accrual of penalties pending its decision and you did not seek judicial review of the IBLA's decision; or

(4) A final non-appealable judgment of a court of competent jurisdiction is entered, if you sought judicial review of the IBLA's decision and the Department or the appropriate court suspended compliance with the IBLA's decision pending the adjudication of the case.

(e) If you do not pay, that amount is subject to collection under the provisions of § 250.1477.

§ 250.1476 Can BSEE reduce my penalty once it is assessed?

Under 30 U.S.C. 1719(g), the Director or his or her delegate may compromise or reduce civil penalties assessed under this part.

§ 250.1477 How may BSEE collect the penalty?

(a) BSEE may use all available means to collect the penalty including, but not limited to:

(1) Requiring the lease surety, for amounts owed by lessees, to pay the penalty;

(2) Deducting the amount of the penalty from any sums the United States owes to you; and

(3) Using judicial process to compel your payment under 30 U.S.C. 1719(k).

(b) If the Department uses judicial process, or if you seek judicial review under § 250.1474 and the court upholds assessment of a penalty, 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 § 250.1474. The amount of any penalty, as finally determined, may be deducted from any sum owing to you by the United States.

CRIMINAL PENALTIES

§ 250.1480 May the United States criminally prosecute me for violations under Federal oil and gas leases?

If you commit an act for which a civil penalty is provided at 30 U.S.C. 1719(d) and § 250.1460(b), the United States may pursue criminal penalties as provided at 30 U.S.C. 1720, in addition to any authority for prosecution under other statutes.

Subpart O—Well Control and Production Safety Training

§ 250.1500 Definitions.

Terms used in this subpart have the following meaning:

Contractor and contract personnel mean anyone, other than an employee of the lessee, performing well control, deepwater well control, or production safety duties for the lessee.

Deepwater well control means well control when you are using a subsea BOP system.

Employee means direct employees of the lessees who are assigned well control, deepwater well control, or production safety duties.

I or you means the lessee engaged in oil, gas, or sulphur operations in the Outer Continental Shelf (OCS).

Lessee means a person who has entered into a lease with the United States to explore for, develop, and produce the leased minerals. The term lessee also includes an owner of operating rights for that lease and the BOEM-approved assignee of that lease.

Periodic means occurring or recurring at regular intervals. Each lessee must specify the intervals for periodic training and periodic assessment of training needs in their training programs.

Production operations include, but are not limited to, separation, dehydration, compression, sweetening, and metering operations.

Production safety includes measures, practices, procedures, and equipment to ensure safe, accident-free, and pollution-free production operations, as well as installation, repair, testing, maintenance, and operation of surface and subsurface safety equipment.

Well completion/well workover means those operations following the drilling of a well that are intended to establish or restore production.

Well-control means methods used to minimize the potential for the well to flow or kick and to maintain control of the well in the event of flow or a kick. Well-control applies to drilling, well-completion, well-workover, abandonment, and well-servicing operations. It includes measures, practices, procedures and equipment, such as fluid flow monitoring, to ensure safe and environmentally protective drilling, completion, abandonment, and workover operations as well as the installation, repair, maintenance, and operation of surface and subsea well-control equipment.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50896, Aug. 22, 2012]

§ 250.1501 What is the goal of my training program?

The goal of your training program must be safe and clean OCS operations. To accomplish this, you must ensure that your employees and contract personnel engaged in well control, deepwater well control, or production safety operations understand and can properly perform their duties.

§ 250.1503 What are my general responsibilities for training?

(a) You must establish and implement a training program so that all of your employees are trained to competently perform their assigned well control, deepwater well control, and production safety duties. You must verify that your employees understand and can perform the assigned well control, deepwater well control, or production safety duties.

(b) If you conduct operations with a subsea BOP stack, your employees and contract personnel must be trained in deepwater well control. The trained employees and contract personnel must have a comprehensive knowledge of deepwater well control equipment, practices, and theory.

(c) You must have a training plan that specifies the type, method(s), length, frequency, and content of the training for your employees. Your training plan must specify the method(s) of verifying employee understanding and performance. This plan must include at least the following information:

(1) Procedures for training employees in well control, deepwater well control, or production safety practices;

(2) Procedures for evaluating the training programs of your contractors;

(3) Procedures for verifying that all employees and contractor personnel engaged in well control, deepwater well control, or production safety operations can perform their assigned duties;

(4) Procedures for assessing the training needs of your employees on a periodic basis;

(5) Recordkeeping and documentation procedures; and

(6) Internal audit procedures.

(d) Upon request of the District Manager or Regional Supervisor, you must provide:

(1) Copies of training documentation for personnel involved in well control, deepwater well control, or production safety operations during the past 5 years; and

(2) A copy of your training plan.

§ 250.1504 May I use alternative training methods?

You may use alternative training methods. These methods may include computer-based learning, films, or their equivalents. This training should be reinforced by appropriate demonstrations and ''hands-on'' training. Alternative training methods must be conducted according to, and meet the objectives of, your training plan.

§ 250.1505 Where may I get training for my employees?

You may get training from any source that meets the requirements of your training plan.

§ 250.1506 How often must I train my employees?

You determine the frequency of the training you provide your employees. You must do all of the following:

(a) Provide periodic training to ensure that employees maintain understanding of, and competency in, well control, deepwater well control, or production safety practices;

(b) Establish procedures to verify adequate retention of the knowledge and skills that employees need to perform their assigned well control, deepwater well control, or production safety duties; and

(c) Ensure that your contractors' training programs provide for periodic training and verification of well control, deepwater well control, or production safety knowledge and skills.

§ 250.1507 How will BSEE measure training results?

BSEE may periodically assess your training program, using one or more of the methods in this section.

(a) *Training system audit.* BSEE or its authorized representative may conduct a training system audit at your office. The training system audit will compare your training program against this subpart. You must be prepared to explain your overall training program and produce evidence to support your explanation.

(b) *Employee or contract personnel interviews.* BSEE or its authorized representative may conduct interviews at either onshore or offshore locations to inquire about the types of training that were provided, when and where this training was conducted, and how effective the training was.

(c) *Employee or contract personnel testing.* BSEE or its authorized representative may conduct testing at either onshore or offshore locations for the purpose of evaluating an individual's knowledge and skills in perfecting well control, deepwater well control, and production safety duties.

(d) *Hands-on production safety, simulator, or live well testing.* BSEE or its authorized representative may conduct tests at either onshore or offshore locations. Tests will be designed to evaluate the competency of your employees or contract personnel in performing their assigned well control, deepwater well control, and production safety duties. You are responsible for the costs associated with this testing, excluding salary and travel costs for BSEE personnel.

§ 250.1508 What must I do when BSEE administers written or oral tests?

BSEE or its authorized representative may test your employees or contract personnel at your worksite or at an onshore location. You and your contractors must:

(a) Allow BSEE or its authorized representative to administer written or oral tests; and

(b) Identify personnel by current position, years of experience in present position, years of total oil field experience, and employer's name (e.g., operator, contractor, or sub-contractor company name).

§ 250.1509 What must I do when BSEE administers or requires hands-on, simulator, or other types of testing?

If BSEE or its authorized representative conducts, or requires you or your contractor to conduct hands-on, simulator, or other types of testing, you must:

(a) Allow BSEE or its authorized representative to administer or witness the testing;

(b) Identify personnel by current position, years of experience in present position, years of total oil field experience, and employer's name (e.g., operator, contractor, or sub-contractor company name); and

(c) Pay for all costs associated with the testing, excluding salary and travel costs for BSEE personnel.

§ 250.1510 What will BSEE do if my training program does not comply with this subpart?

If BSEE determines that your training program is not in compliance, we may initiate one or more of the following enforcement actions:

(a) Issue an Incident of Noncompliance (INC);

(b) Require you to revise and submit to BSEE your training plan to address identified deficiencies;

(c) Assess civil/criminal penalties; or

(d) Initiate disqualification procedures.

Subpart P—Sulphur Operations

§ 250.1600 Performance standard.

Operations to discover, develop, and produce sulphur in the OCS shall be in accordance with a BOEM-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.

§ 250.1601 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.

§ 250.1602 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, I, J, M, N, O, and Q of this part and the applicable provisions of 30 CFR 550 subparts A, B, C, J and N.

(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 and the applicable provisions of 30 CFR 550, subpart K, where such provisions specifically are referenced in this subpart.

§ 250.1603 Determination of sulphur deposit.

(a) Upon receipt of a written request from the lessee, the District Manager 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.

§ 250.1604 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 § 250.490 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 § 250.490 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 §§ 250.109 through 250.113 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 § 250.114 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.* All drilling units being used for drilling, well-completion, or well-workover operations that have both a traveling block and a crown block must be equipped with a safety device that is designed to prevent the traveling block from striking the crown block. The device must be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check must be entered in the operations log.

§ 250.1605 Drilling requirements.

(a) *Sulphur leases.* Lessees of OCS sulphur leases shall conduct drilling operations in accordance with §§ 250.1605 through 250.1619 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 Manager.

(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 BSEE–0123, Application for Permit to Drill (APD), in accordance with § 250.1617 of this subpart. After a drilling unit has been approved by a BSEE district office, the information required in this paragraph need not be resubmitted unless required by the District Manager 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 Manager. The type of information to be collected and reported will be determined by the District Manager 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 30 CFR 550.211 through 550.228 and 30 CFR 550.241 through 550.262 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 Manager may require that additional surveys and soil borings be performed and the results submitted for review and evaluation by the District Manager 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.* You must operate a crane installed on fixed platforms according to § 250.108 of this subpart.

(h) *Diesel-engine air intakes.* Diesel-engine air intakes must be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with either remote-operated manual or automatic-shutdown devices. Diesel engines that are not continuously attended must be equipped with automatic shutdown devices.

§ 250.1606 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.

§ 250.1607 Field rules.

When geological and engineering information in a field enables a District Manager to determine specific operating requirements, field rules may be established for drilling, well completion, or well workover on the District Manager'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 Manager or upon the request of a lessee.

§ 250.1608 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 Manager 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 Manager. 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 Manager, 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 Manager 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 Manager 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 Manager. 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.

§ 250.1609 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 time lapse 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36151, June 6, 2016]

§ 250.1610 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. Accumulator regulators supplied by rig air that do not have a secondary source of pneumatic supply must 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 Manager;

(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 Manager.

(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.

§ 250.1611 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 Manager. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Manager.

(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) 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. 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 Manager. 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 BSEE 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 Manager.

§ 250.1612 Well-control drills.

Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in § 250.711 or as approved by the District Manager.

[81 FR 26037, Apr. 29, 2016]

§ 250.1613 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) 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.

(c) 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.

(d) 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.

§ 250.1614 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 §§ 250.455 through 250.459 of this part, except that the installation of an operable degasser in the mud system as required in § 250.456(g) is not required for sulphur operations.

§ 250.1615 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 Manager in lieu of the above requirements if cap rock casing has been set.

§ 250.1616 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.

§ 250.1617 Application for permit to drill.

(a) Before drilling a well under a BOEM-approved Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, you must file Form BSEE–0123, APD, with the District Manager for approval. The submission of your APD must be accompanied by payment of the service fee listed in § 250.125. Before starting operations, you must receive written approval from the District Manager unless you received oral approval under § 250.140.

(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 a BSEE district, the information need not be resubmitted unless required by the District Manager or there are changes in the equipment that affect the rated capacity of the unit.

(c) An APD shall include a fully completed Form BSEE–0123 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 Manager.

(d) Public information copies of the APD shall be submitted in accordance with § 250.186 of this part.

§ 250.1618 Application for permit to modify.

(a) You must submit requests for changes in plans, changes in major drilling equipment, proposals to deepen, sidetrack, complete, workover, or plug back a well, or engage in similar activities to the District Manager on Form BSEE–0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125. Before starting operations associated with the change, you must receive written approval from the District Manager unless you received oral approval under § 250.140.

(b) The Form BSEE–0124 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 BSEE–0124 shall be submitted in accordance with § 250.186 of this part.

§ 250.1619 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 Manager. 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 Manager 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 § 250.170 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 Manager duplicate copies of the records of all activities related to and conducted during the suspension or temporary prohibition on, or attached to, Form BSEE–0125, End of Operations Report, or Form BSEE–0124, Application for Permit to Modify, as appropriate.

(c) Upon request by the District Manager or Regional 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 Manager. 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 Manager in duplicate as soon as available but not later than 30 days after completion of such operations for each well.

(e) If the District Manager determines that circumstances warrant, the lessee shall submit any other reports and records of operations in the manner and form prescribed by the District Manager.

§ 250.1620 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 §§ 250.1620 through 250.1626 of this part and other provisions of this part as appropriate (see §§ 250.501 and 250.601 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.

§ 250.1621 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 BSEE review.

§ 250.1622 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 Manager. Approval for such operations shall be requested on Form BSEE–0124. Approvals by the District Manager 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 BSEE–0124 (or with Form BSEE–0123):

(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 BSEE–0125, including a schematic of the tubing and the results of any well tests, shall be submitted to the District Manager.

(2) Within 30 days after completing the well-workover operation, except routine operations, Form BSEE–0124 shall be submitted to the District Manager and shall include the results of any well tests and a new schematic of the well if any subsurface equipment has been changed.

§ 250.1623 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 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.

§ 250.1624 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 § 250.1622 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.

§ 250.1625 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 Manager. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Manager.

(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 Manager. 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 BSEE 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 Manager.

§ 250.1626 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.

§ 250.1627 Production requirements.

(a) The lessee shall conduct sulphur production operations in compliance with the approved Development and Production Plan requirements of §§ 250.1627 through 250.1634 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.

§ 250.1628 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 Manager 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 Manager. 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 (as incorporated by reference in § 250.198);

(3) Electrical system information including a plan of each platform deck, outlining all hazardous areas classified according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (as incorporated by reference in § 250.198), 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 Manager certifying that the new installations conform to the approved designs of this subpart.

(c) *Hydrocarbon handling vessels associated with fuel gas system.* You must protect hydrocarbon handling vessels associated with the fuel gas system with a basic and ancillary surface safety system. This system must be designed, analyzed, installed, tested, and maintained in operating condition in accordance with API RP 14C, Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms (as incorporated by reference in § 250.198). If processing components are to be utilized, other than those for which Safety Analysis Checklists are included in API RP 14C, you must use the analysis technique and documentation specified therein to determine the effect 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 Manager 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 Manager. 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, as incorporated by reference in § 250.198) and the related Safety Analysis Function Evaluation chart (API RP 14C, subsection 4.3c, as incorporated by reference in § 250.198).

(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 (as incorporated by reference in § 250.198);

(4) Electrical system information including the following:

(i) A plan of each platform deck, outlining all hazardous areas classified according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (as incorporated by reference in § 250.198), 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 Manager 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.

§ 250.1629 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 § 250.1628 of this part).

(b) *Design, installation, and operation of additional production systems, including fuel gas handling safety systems.* (1) Pressure and fired vessels must be designed, fabricated, and code stamped in accordance with the applicable provisions of sections I, IV, and VIII of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (as specified in § 250.198). Pressure and fired vessels must have maintenance inspection, rating, repair, and alteration performed in accordance with the applicable provisions of API Pressure Vessel Inspections Code: In-Service Inspection, Rating, Repair, and Alteration, API 510 (except Sections 5.8 and 9.5) (as incorporated by reference in § 250.198).

(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 (as specified in § 250.198). 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 Manager. 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.* You must equip engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4) (as incorporated by reference in § 250.198). Exhaust piping from diesel engines must be equipped with spark arresters.

(3) *Firefighting systems.* Firefighting systems must 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 (as incorporated by reference in § 250.198), and must be subject to the approval of the District Manager. Additional requirements must 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 Manager;

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Manager 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 (as incorporated by reference in § 250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (as incorporated by reference in § 205.198).

(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 Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems must be an approved type, designed and installed according to API RP 14C, API RP 14G, and either API RP 14F or API RP 14FZ (the preceding four documents as incorporated by reference in § 250.198).

(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.

§ 250.1630 Safety-system testing and records.

(a) *Inspection and testing.* You must inspect and successfully test safety system devices at the interval specified below or more frequently if operating conditions warrant. Testing must be in accordance with API RP 14C, Appendix D (as incorporated by reference in § 250.198). For safety system devices other than those listed in API RP 14C, Appendix D, you must utilize the analysis technique and documentation specified therein 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 (excluding electronic pressure transmitters and level sensors) must be inspected and tested at least once each calendar month, but at no time may 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) The following electronic pressure transmitters and level sensors must be inspected and tested at least once every 3 months, but at no time may more than 120 days elapse between tests:

(i) All PSH or PSL, and

(ii) All LSH and LSL controls.

(4) All pumps for firewater systems shall be inspected and operated weekly.

(5) 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.

(6) Prior to the commencement of production, the lessee shall notify the District Manager when the lessee is ready to conduct a preproduction test and inspection of the safety system. The lessee shall also notify the District Manager 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 Manager. These records shall be available for BSEE 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.

§ 250.1631 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 BSEE review.

§ 250.1632 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).

§ 250.1633 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.

§ 250.1634 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.

Subpart Q—Decommissioning Activities

GENERAL

§ 250.1700 What do the terms "decommissioning", "obstructions", and "facility" mean?

(a) *Decommissioning* means:

(1) Ending oil, gas, or sulphur operations; and

(2) Returning the lease or pipeline right-of-way to a condition that meets the requirements of regulations of BSEE and other agencies that have jurisdiction over decommissioning activities.

(b) *Obstructions* mean structures, equipment, or objects that were used in oil, gas, or sulphur operations or marine growth that, if left in place, would hinder other users of the OCS. Obstructions may include, but are not limited to, shell mounds, wellheads, casing stubs, mud line suspensions, well protection devices, subsea trees, jumper assemblies, umbilicals, manifolds, termination skids, production and pipeline risers, platforms, templates, pilings, pipelines, pipeline valves, and power cables.

(c) *Facility* means any installation other than a pipeline used for oil, gas, or sulphur activities that is permanently or temporarily attached to the seabed on the OCS. Facilities include production and pipeline risers, templates, pilings, and any other facility or equipment that constitutes an obstruction such as jumper assemblies, termination skids, umbilicals, anchors, and mooring lines.

§ 250.1701 Who must meet the decommissioning obligations in this subpart?

(a) Lessees and owners of operating rights are jointly and severally responsible for meeting decommissioning obligations for facilities on leases, including the obligations related to lease-term pipelines, as the obligations accrue and until each obligation is met.

(b) All holders of a right-of-way are jointly and severally liable for meeting decommissioning obligations for facilities on their right-of-way, including right-of-way pipelines, as the obligations accrue and until each obligation is met.

(c) In this subpart, the terms ''you'' or ''I'' refer to lessees and owners of operating rights, as to facilities installed under the authority of a lease, and to right-of-way holders as to facilities installed under the authority of a right-of-way.

§ 250.1702 When do I accrue decommissioning obligations?

You accrue decommissioning obligations when you do any of the following:

(a) Drill a well;

(b) Install a platform, pipeline, or other facility;

(c) Create an obstruction to other users of the OCS;

(d) Are or become a lessee or the owner of operating rights of a lease on which there is a well that has not been permanently plugged according to this subpart, a platform, a lease term pipeline, or other facility, or an obstruction;

(e) Are or become the holder of a pipeline right-of-way on which there is a pipeline, platform, or other facility, or an obstruction; or

(f) Re-enter a well that was previously plugged according to this subpart.

§ 250.1703 What are the general requirements for decommissioning?

When your facilities are no longer useful for operations, you must:

(a) Get approval from the appropriate District Manager before decommissioning wells and from the Regional Supervisor before decommissioning platforms and pipelines or other facilities;

(b) Permanently plug all wells. Packers and bridge plugs used as qualified mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in § 250.198). You must have two independent barriers, one being an ANSI/API Spec. 11D1 qualified mechanical barrier, in the exposed center wellbore prior to removing the tree and/or well control equipment;

(c) Remove all platforms and other facilities, except as provided in §§ 250.1725(a) and 250.1730.

(d) Decommission all pipelines;

(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;

(f) Follow all applicable requirements of subpart G of this part; and

(g) Conduct all decommissioning activities in a manner that is safe, does not unreasonably interfere with other uses of the OCS, and does not cause undue or serious harm or damage to the human, marine, or coastal environment.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26037, Apr. 29 2016; 84 FR 21984, May 15, 2019]

§ 250.1704 What decommissioning applications and reports must I submit and when must I submit them?

You must submit decommissioning applications, receive approval of those applications, and submit subsequent reports according to the requirements and deadlines in the following table.

DECOMMISSIONING APPLICATIONS AND REPORTS TABLE

Decommissioning applications and reports	When to submit	Instructions
(a) Initial platform removal application [not required in the Gulf of Mexico OCS Region].	In the Pacific OCS Region or Alaska OCS Region, submit the application to the Regional Supervisor at least 2 years before production is projected to cease.	Include information required under § 250.1726.
(b) Final removal application for a platform or other facility.	Before removing a platform or other facility in the Gulf of Mexico OCS Region, or not more than 2 years after the submittal of an initial platform removal application to the Pacific OCS Region and the Alaska OCS Region.	Include information required under § 250.1727.
(c) Post-removal report for a platform or other facility.	Within 30 days after you remove a platform or other facility.	Include information required under § 250.1729.
(d) Pipeline decommissioning application.	Before you decommission a pipeline ..	Include information required under § 250.1751(a) or § 250.1752(a), as applicable.
(e) Post-pipeline decommissioning report.	Within 30 days after you decommission a pipeline.	Include information required under § 250.1753.
(f) Site clearance report for a platform or other facility.	Within 30 days after you complete site clearance verification activities.	Include information required under § 250.1743(b).
(g) Form BSEE–0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125;.	(1) Before you temporarily abandon or permanently plug a well or zone,.	(i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under § 250.731.
	(2) Before you install a subsea protective device,.	Refer to § 250.1722(a).
	(3) Before you remove any casing stub or mud line suspension equipment and any subsea protective device,.	Refer to § 250.1723.
	(4) Within 30 days after you complete site clearance verification activities,.	Include information required under § 250.1743(a).
(h) Form BSEE–0125, End of Operations Report (EOR);.	(1) Within 30 days after you complete a protective device trawl test,.	Include information required under § 250.1722(d).

DECOMMISSIONING APPLICATIONS AND REPORTS TABLE—Continued

Decommissioning applications and reports	When to submit	Instructions
	(2) Within 30 days after completion of decommissioning activity,.	Include information required under §§ 250.1712 and 250.1721.
(i) A certified summary of expenditures for permanently plugging any well, removal of any platform or other facility, clearance of any site after wells have been plugged or platforms or facilities removed, and decommissioning of pipelines.	Within 120 days after completion of each decommissioning activity specified in this paragraph.	Submit to the Regional Supervisor a complete summary of expenditures actually incurred for each decommissioning activity (including, but not limited to, the use of rigs, vessels, equipment, supplies and materials; transportation of any kind; personnel; and services). Include in, or attach to, the summary a certified statement by an authorized representative of your company attesting to the truth, accuracy and completeness of the summary. The Regional Supervisor may provide specific instructions or guidance regarding how to submit the certified summary.
(j) If requested by the Regional Supervisor, additional information in support of any decommissioning activity expenditures included in a summary submitted under paragraph (i) of this section.	Within a reasonable time as determined by the Regional Supervisor.	The Regional Supervisor will review the summary and may provide specific instructions or guidance regarding the submission of additional information (including, but not limited to, copies of contracts and invoices), if requested, to complete or otherwise support the summary.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50896, Aug. 22, 2012; 80 FR 75810, Dec. 4, 2015; 81 FR 26037, Apr. 29, 2016; 81 FR 80591, Nov. 16, 2016; 84 FR 21984, May 15, 2019]

§§ 250.1705–250.1709 [Reserved]

PERMANENTLY PLUGGING WELLS

§ 250.1710 When must I permanently plug all wells on a lease?

You must permanently plug all wells on a lease within 1 year after the lease terminates.

§ 250.1711 When will BSEE order me to permanently plug a well?

BSEE will order you to permanently plug a well if that well:

(a) Poses a hazard to safety or the environment; or

(b) Is not useful for lease operations and is not capable of oil, gas, or sulphur production in paying quantities.

§ 250.1712 What information must I submit before I permanently plug a well or zone?

Before you permanently plug a well or zone, you must submit form BSEE–0124, Application for Permit to Modify, to the appropriate District Manager and receive approval. A request for approval must contain the following information:

(a) The reason you are plugging the well (or zone), for completions with production amounts specified by the Regional Supervisor, along with substantiating information demonstrating its lack of capacity for further profitable production of oil, gas, or sulfur;

(b) Recent well test data and pressure data, if available;

(c) Maximum possible surface pressure, and how it was determined;

(d) Type and weight of well-control fluid you will use;

(e) A description of the work;

(f) A current and proposed well schematic and description that includes:

(1) Well depth;

(2) All perforated intervals that have not been plugged;

(3) Casing and tubing depths and details;

(4) Subsurface equipment;

(5) Estimated tops of cement (and the basis of the estimate) in each casing annulus;

(6) Plug locations;

(7) Plug types;

(8) Plug lengths;

(9) Properties of mud and cement to be used;

(10) Perforating and casing cutting plans;

(11) Plug testing plans;

(12) Casing removal (including information on explosives, if used);

(13) Proposed casing removal depth; and

(14) Your plans to protect archaeological and sensitive biological features, including anchor damage during plugging operations, a brief assessment of the environmental impacts of the plugging operations, and the procedures and mitigation measures you will take to minimize such impacts; and

(g) Certification by a Registered Professional Engineer of the well abandonment design and procedures and that all plugs meet the requirements in the table in § 250.1715. In addition to the requirements of § 250.1715, the Registered Professional Engineer must also certify the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in § 250.420(b)(3). The Registered Professional Engineer must be registered in a State of the United States and have sufficient expertise and experience to perform the certification. You must submit this certification with your APM (Form BSEE–0124).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50900, Aug. 22, 2012]

§ 250.1713 [Reserved]

§ 250.1714 What must I accomplish with well plugs?

You must ensure that all well plugs:

(a) Provide downhole isolation of hydrocarbon and sulphur zones;

(b) Protect freshwater aquifers; and

(c) Prevent migration of formation fluids within the wellbore or to the seafloor.

§ 250.1715 How must I permanently plug a well?

(a) You must permanently plug wells according to the table in this section. The District Manager may require additional well plugs as necessary.

PERMANENT WELL PLUGGING REQUIREMENTS

If you have . . .	Then you must use . . .
(1) Zones in open hole,	Cement plug(s) set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata.
(2) Open hole below casing,	(i) A cement plug, set by the displacement method, at least 100 feet above and below deepest casing shoe; (ii) A cement retainer with effective back-pressure control set 50 to 100 feet above the casing shoe, and a cement plug that extends at least 100 feet below the casing shoe and at least 50 feet above the retainer; or (iii) A bridge plug set 50 feet to 100 feet above the shoe with 50 feet of cement on top of the bridge plug, for expected or known lost circulation conditions.
(3) A perforated zone that is currently open and not previously squeezed or isolated,	(i) A method to squeeze cement to all perforations; (ii) A cement plug set by the displacement method, at least 100 feet above to 100 feet below the perforated interval, or down to a casing plug, whichever is less; or (iii) If the perforated zones are isolated from the hole below, you may use any of the plugs specified in paragraphs (a)(3)(iii)(A) through (E) of this section instead of those specified in paragraphs (a)(3)(i) and (a)(3)(ii) of this section. (A) A cement retainer with effective back-pressure control set 50 to 100 feet above the top of the perforated interval, and a cement plug that extends at least 100 feet below the bottom of the perforated interval with at least 50 feet of cement above the retainer; (B) A casing bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug; (C) A cement plug at least 200 feet in length, set by the displacement method, with the bottom of the plug no more than 100 feet above the perforated interval; (D) A through-tubing basket plug set no more than 100 feet above the perforated interval with at least 50 feet of cement on top of the basket plug; or (E) A tubing plug set no more than 100 feet above the perforated interval topped with a sufficient volume of cement so as to extend at least 100 feet above the uppermost packer in the wellbore and at least 300 feet of cement in the casing annulus immediately above the packer.
(4) A casing stub where the stub end is within the casing,	(i) A cement plug set at least 100 feet above and below the stub end; (ii) A cement retainer or bridge plug set at least 50 to 100 feet above the stub end with at least 50 feet of cement on top of the retainer or bridge plug; or

PERMANENT WELL PLUGGING REQUIREMENTS—Continued

If you have . . .	Then you must use . . .
	(iii) A cement plug at least 200 feet long with the bottom of the plug set no more than 100 feet above the stub end.
(5) A casing stub where the stub end is below the casing,	A plug as specified in paragraph (a)(1) or (a)(2) of this section, as applicable.
(6) An annular space that communicates with open hole and extends to the mud line,	A cement plug at least 200 feet long set in the annular space. For a well completed above the ocean surface, you must pressure test each casing annulus to verify isolation.
(7) A subsea well with unsealed annulus,	A cutter to sever the casing, and you must set a stub plug as specified in paragraphs (a)(4) and (a)(5) of this section.
(8) A well with casing,	A cement surface plug at least 150 feet long set in the smallest casing that extends to the mud line with the top of the plug no more than 150 feet below the mud line.
(9) Fluid left in the hole,	A fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.
(10) Permafrost areas,	(i) A fluid to be left in the hole that has a freezing point below the temperature of the permafrost, and a treatment to inhibit corrosion; and (ii) Cement plugs designed to set before freezing and have a low heat of hydration.
(11) Removed the barriers required in § 250.420(b)(3) for the well to be completed	Two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in § 250.420(b)(3) once the well is to be placed in a permanent or temporary abandonment..

(b) You must test the first plug below the surface plug and all plugs in lost circulation areas that are in open hole. The plug must pass one of the following tests to verify plug integrity:

(1) A pipe weight of at least 15,000 pounds on the plug; or

(2) A pump pressure of at least 1,000 pounds per square inch. Ensure that the pressure does not drop more than 10 percent in 15 minutes. The District Manager may require you to tests other plug(s).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50900, Aug. 22, 2012; 81 FR 26038, Apr. 29, 2016]

§ 250.1716 To what depth must I remove wellheads and casings?

(a) Unless the District Manager approves an alternate depth under paragraph (b) of this section, you must remove all wellheads and casings to at least 15 feet below the mud line.

(b) The District Manager may approve an alternate removal depth if:

(1) The wellhead or casing would not become an obstruction to other users of the seafloor or area, and geotechnical and other information you provide demonstrate that erosional processes capable of exposing the obstructions are not expected; or

(2) You determine, and BSEE concurs, that you must use divers, and the seafloor sediment stability poses safety concerns; or

(3) The water depth is greater than 1,000 feet.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21985, May 15, 2019]

§ 250.1717 [Reserved]

TEMPORARY ABANDONED WELLS

§ 250.1721 If I temporarily abandon a well that I plan to re-enter, what must I do?

You may temporarily abandon a well when it is necessary for proper development and production of a lease. To temporarily abandon a well, you must do all of the following:

(a) Submit form BSEE–0124, Application for Permit to Modify, and the applicable information required by § 250.1712 to the appropriate District Manager and receive approval;

(b) Adhere to the plugging and testing requirements for permanently plugged wells listed in the table in § 250.1715, except for § 250.1715(a)(8). You do not need to sever the casings, remove the wellhead, or clear the site;

(c) Set a bridge plug or a cement plug at least 100-feet long 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;

(d) Set a retrievable or a permanent-type bridge plug or a cement plug at least 100 feet long in the inner-most casing. The top of the bridge plug or cement plug must be no more than 1,000 feet below the mud line. BSEE may consider approving alternate requirements for subsea wells case-by-case;

(e) Identify and report subsea wellheads, casing stubs, or other obstructions that extend above the mud line according to U.S. Coast Guard (USCG) requirements;

(f) Except in water depths greater than 300 feet, protect subsea wellheads, casing stubs, mud line suspensions, or other obstructions remaining above the seafloor by using one of the following methods, as approved by the District Manager or Regional Supervisor:

(1) A caisson designed according to 30 CFR 250, subpart I, and equipped with aids to navigation;

(2) A jacket designed according to 30 CFR 250, subpart I, and equipped with aids to navigation; or

(3) A subsea protective device that meets the requirements in § 250.1722.

(g) Submit certification by a Registered Professional Engineer of the well abandonment design and procedures and that all plugs meet the requirements of paragraph (b) of this section. In addition to the requirements of paragraph (b) of this section, the Registered Professional Engineer must also certify the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in § 250.420(b)(3). The Registered Professional Engineer must be registered in a State of the United States and have sufficient expertise and experience to perform the certification. You must submit this certification with your APM (Form BSEE–0124) required by § 250.1712 of this part.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50900, Aug. 22, 2012; 81 FR 26038, Apr. 29, 2016]

§ 250.1722 If I install a subsea protective device, what requirements must I meet?

If you install a subsea protective device under § 250.1721(f)(3), you must install it in a manner that allows fishing gear to pass over the obstruction without damage to the obstruction, the protective device, or the fishing gear.

(a) Use form BSEE–0124, Application for Permit to Modify to request approval from the appropriate District Manager to install a subsea protective device.

(b) The protective device may not extend more than 10 feet above the seafloor (unless BSEE approves otherwise).

(c) You must trawl over the protective device when you install it (adhere to the requirements at § 250.1741(d) through (h)). If the trawl does not pass over the protective device or causes damage to it, you must notify the appropriate District Manager within 5 days and perform remedial action within 30 days of the trawl;

(d) Within 30 days after you complete the trawling test described in paragraph (c) of this section, submit a report to the appropriate District Manager using form BSEE–0125, End of Operations Report (EOR) that includes the following:

(1) The date(s) the trawling test was performed and the vessel that was used;

(2) A plat at an appropriate scale showing the trawl lines;

(3) A description of the trawling operation and the net(s) that were used;

(4) An estimate by the trawling contractor of the seafloor penetration depth achieved by the trawl;

(5) A summary of the results of the trawling test including a discussion of any snags and interruptions, a description of any damage to the protective covering, the casing stub or mud line suspension equipment, or the trawl, and a discussion of any snag removals requiring diver assistance; and

(6) A letter signed by your authorized representative stating that he/she witnessed the trawling test.

(e) If a temporarily abandoned well is protected by a subsea device installed in a water depth less than 100 feet, mark the site with a buoy installed according to the USCG requirements.

(f) Provide annual reports to the Regional Supervisor describing your plans to either re-enter and complete the well or to permanently plug the well.

(g) Ensure that all subsea wellheads, casing stubs, mud line suspensions, or other obstructions in water depths less than 300 feet remain protected.

(1) To confirm that the subsea protective covering remains properly installed, either conduct a visual inspection or perform a trawl test at least annually.

(2) If the inspection reveals that a casing stub or mud line suspension is no longer properly protected, or if the trawl does not pass over the subsea protective covering without causing damage to the covering, the casing stub or mud line suspension equipment, or the trawl, notify the appropriate District Manager within 5 days, and perform the necessary remedial work within 30 days of discovery of the problem.

(3) In your annual report required by paragraph (f) of this section, include the inspection date, results, and method used and a description of any remedial work you will perform or have performed.

(h) You may request approval to waive the trawling test required by paragraph (c) of this section if you plan to use either:

(1) A buoy with automatic tracking capabilities installed and maintained according to USCG requirements at 33 CFR part 67 (or its successor); or

(2) A design and installation method that has been proven successful by trawl testing of previous protective devices of the same design and installed in areas with similar bottom conditions.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21985, May 15, 2019]

§ 250.1723 What must I do when it is no longer necessary to maintain a well in temporary abandoned status?

If you or BSEE determines that continued maintenance of a well in a temporary abandoned status is not necessary for the proper development or production of a lease, you must:

(a) Promptly and permanently plug the well according to § 250.1715;

(b) Remove any casing stub or mud line suspension equipment and any subsea protective covering. You must submit a request for approval to perform such work to the appropriate District Manager using form BSEE–0124, Application for Permit to Modify; and

(c) Clear the well site according to §§ 250.1740 through 250.1742.

REMOVING PLATFORMS AND OTHER FACILITIES

§ 250.1725 When do I have to remove platforms and other facilities?

(a) You must remove all platforms and other facilities within 1 year after the lease or pipeline right-of-way terminates, unless you receive approval to maintain the structure to conduct other activities. Platforms include production platforms, well jackets, single-well caissons, and pipeline accessory platforms. Other activities include those supporting OCS oil and gas production and transportation, as well as other energy-related or marine-related uses (including LNG) for which adequate financial assurance for decommissioning has been provided to a Federal agency which has given BSEE a commitment that it has and will exercise authority to compel the performance of decommissioning within a time following cessation of the new use acceptable to BSEE. The approval will specify:

(1) Whether you must continue to maintain any financial assurance for decommissioning; and

(2) Whether, and under what circumstances, you must perform any decommissioning not performed by the new facility owner/user.

(b) Before you may remove a platform or other facility, you must submit a final removal application to the Regional Supervisor for approval and include the information listed in § 250.1727.

(c) You must remove a platform or other facility according to the approved application.

(d) You must flush all production risers with seawater before you remove them.

(e) You must notify the Regional Supervisor at least 48 hours before you begin the removal operations.

§ 250.1726 When must I submit an initial platform removal application and what must it include?

An initial platform removal application is required only for leases and pipeline rights-of-way in the Pacific OCS Region or the Alaska OCS Region. It must include the following information:

(a) Platform or other facility removal procedures, including the types of vessels and equipment you will use;

(b) Facilities (including pipelines) you plan to remove or leave in place;

(c) Platform or other facility transportation and disposal plans;

(d) Plans to protect marine life and the environment during decommissioning operations, including a brief assessment of the environmental impacts of the operations, and procedures and mitigation measures that you will take to minimize the impacts; and

(e) A projected decommissioning schedule.

§ 250.1727 What information must I include in my final application to remove a platform or other facility?

You must submit to the Regional Supervisor, a final application for approval to remove a platform or other facility. Your application must be accompanied by payment of the service fee listed in § 250.125. If you are proposing to use explosives, provide three copies of the application. If you are not proposing to use explosives, provide two copies of the application. Include the following information in the final removal application, as applicable:

(a) Identification of the applicant including:

(1) Lease operator/pipeline right-of-way holder;

(2) Address;

(3) Contact person and telephone number; and

(4) Shore base.

(b) Identification of the structure you are removing including:

(1) Platform Name/BSEE Complex ID Number;

(2) Location (lease/right-of-way, area, block, and block coordinates);

(3) Date installed (year);

(4) Proposed date of removal (Month/Year); and

(5) Water depth.

(c) Description of the structure you are removing including:

(1) Configuration (attach a photograph or a diagram);

(2) Size;

(3) Number of legs/casings/pilings;

(4) Diameter and wall thickness of legs/casings/pilings;

(5) Whether piles are grouted inside or outside;

(6) Brief description of soil composition and condition;

(7) The sizes and weights of the jacket, topsides (by module), conductors, and pilings; and

(8) The maximum removal lift weight and estimated number of main lifts to remove the structure.

(d) A description, including anchor pattern, of the vessel(s) you will use to remove the structure.

(e) Identification of the purpose, including:

(1) Lease expiration/right-of-way relinquishment date; and

(2) Reason for removing the structure.

(f) A description of the removal method, including:

(1) A brief description of the method you will use;

(2) If you are using explosives, the following:

(i) Type of explosives;

(ii) Number and sizes of charges;

(iii) Whether you are using single shot or multiple shots;

(iv) If multiple shots, the sequence and timing of detonations;

(v) Whether you are using a bulk or shaped charge;

(vi) Depth of detonation below the mud line; and

(vii) Whether you are placing the explosives inside or outside of the pilings;

(3) If you will use divers or acoustic devices to conduct a pre-removal survey to detect the presence of turtles and marine mammals, a description of the proposed detection method; and

(4) A statement whether or not you will use transducers to measure the pressure and impulse of the detonations.

(g) Your plans for transportation and disposal (including as an artificial reef) or salvage of the removed platform.

(h) If available, the results of any recent biological surveys conducted in

the vicinity of the structure and recent observations of turtles or marine mammals at the structure site.

(i) Your plans to protect archaeological and sensitive biological features during removal operations, including a brief assessment of the environmental impacts of the removal operations and procedures and mitigation measures you will take to minimize such impacts.

(j) A statement whether or not you will use divers to survey the area after removal to determine any effects on marine life.

§ 250.1728 To what depth must I remove a platform or other facility?

(a) Unless the Regional Supervisor approves an alternate depth under paragraph (b) of this section, you must remove all platforms and other facilities (including templates and pilings) to at least 15 feet below the mud line.

(b) The Regional Supervisor may approve an alternate removal depth if:

(1) The remaining structure would not become an obstruction to other users of the seafloor or area, and geotechnical and other information you provide demonstrate that erosional processes capable of exposing the obstructions are not expected; or

(2) You determine, and BSEE concurs, that you must use divers and the seafloor sediment stability poses safety concerns; or

(3) The water depth is greater than 800 meters (2,624 feet).

§ 250.1729 After I remove a platform or other facility, what information must I submit?

Within 30 days after you remove a platform or other facility, you must submit a written report to the Regional Supervisor that includes the following:

(a) A summary of the removal operation including the date it was completed;

(b) A description of any mitigation measures you took; and

(c) A statement signed by your authorized representative that certifies that the types and amount of explosives you used in removing the platform or other facility were consistent with those set forth in the approved removal application.

§ 250.1730 When might BSEE approve partial structure removal or toppling in place?

The Regional Supervisor may grant a departure from the requirement to remove a platform or other facility by approving partial structure removal or toppling in place for conversion to an artificial reef if you meet the following conditions:

(a) The structure becomes part of a State artificial reef program, and the responsible State agency acquires a permit from the U.S. Army Corps of Engineers and accepts title and liability for the structure; and

(b) You satisfy any U.S. Coast Guard (USCG) navigational requirements for the structure.

§ 250.1731 Who is responsible for decommissioning an OCS facility subject to an Alternate Use RUE?

(a) The holder of an Alternate Use RUE issued under 30 CFR part 585 is responsible for all decommissioning obligations that accrue following the issuance of the Alternate Use RUE and which pertain to the Alternate Use RUE. See 30 CFR part 585, subpart J, for additional information concerning the decommissioning responsibilities of an Alternate Use RUE grant holder.

(b) The lessee under the lease originally issued under 30 CFR part 556 will remain responsible for decommissioning obligations that accrued before issuance of the Alternate Use RUE, as well as for decommissioning obligations that accrue following issuance of the Alternate Use RUE to the extent associated with continued activities authorized under this part.

(c) If a lease issued under 30 CFR part 556 is cancelled or otherwise terminated under any provision of this subchapter, the lessee, upon our approval, may defer removal of any OCS facility within the lease area that is subject to an Alternate Use RUE. If we elect to grant such a deferral, the lessee remains responsible for removing the facility upon termination of the Alternate Use RUE and will be required to retain sufficient bonding or other financial assurances to ensure that the

structure is removed or otherwise decommissioned in accordance with the provisions of this subpart.

SITE CLEARANCE FOR WELLS, PLATFORMS, AND OTHER FACILITIES

§ 250.1740 How must I verify that the site of a permanently plugged well, removed platform, or other removed facility is clear of obstructions?

Within 60 days after you permanently plug a well or remove a platform or other facility, you must verify that the site is clear of obstructions by using one of the following methods:

(a) For a well site, you must either:

(1) Drag a trawl over the site;

(2) Scan across the location using sonar equipment;

(3) Inspect the site using a diver;

(4) Videotape the site using a camera on a remotely operated vehicle (ROV); or

(5) Use another method approved by the District Manager if the particular site conditions warrant.

(b) For a platform or other facility site in water depths less than 300 feet, you must drag a trawl over the site.

(c) For a platform or other facility site in water depths 300 feet or more, you must either:

(1) Drag a trawl over the site;

(2) Scan across the site using sonar equipment; or

(3) Use another method approved by the Regional Supervisor if the particular site conditions warrant.

§ 250.1741 If I drag a trawl across a site, what requirements must I meet?

If you drag a trawl across the site in accordance with § 250.1740, you must meet all of the requirements of this section.

(a) You must drag the trawl in a grid-like pattern as shown in the following table:

For a . . .	You must drag the trawl across a . . .
(1) Well site,	300-foot-radius circle centered on the well location.
(2) Subsea well site,	600-foot-radius circle centered on the well location.
(3) Platform site,	1,320-foot-radius circle centered on the location of the platform.
(4) Single-well caisson, well protector jacket, template, or manifold,	600-foot-radius circle centered on the structure location.

(b) You must trawl 100 percent of the limits described in paragraph (a) of this section in two directions.

(c) You must mark the area to be cleared as a hazard to navigation according to USCG requirements until you complete the site clearance procedures.

(d) You must use a trawling vessel equipped with a calibrated navigational positioning system capable of providing position accuracy of ±30 feet.

(e) You must use a trawling net that is representative of those used in the commercial fishing industry (one that has a net strength equal or greater than that provided by No. 18 twine).

(f) You must ensure that you trawl no closer than 300 feet from a shipwreck, and 500 feet from a sensitive biological feature.

(g) If you trawl near an active pipeline, you must meet the requirements in the following table:

For . . .	You must trawl . . .	And you must . . .
(1) Buried active pipelines,		First contact the pipeline owner or operator to determine the condition of the pipeline before trawling over the buried pipeline.
(2) Unburied active pipelines that are 8 inches in diameter or larger,	no closer than 100 feet to the either side of the pipeline,	Trawl parallel to the pipeline Do not trawl across the pipeline.
(3) Unburied smaller diameter active pipelines in the trawl area that have obstructions (e.g., pipeline valves) present,	no closer than 100 feet to either side of the pipeline,	Trawl parallel to the pipeline. Do not trawl across the pipeline.

For . . .	You must trawl . . .	And you must . . .
(4) Unburied active pipelines in the trawl area that are smaller than 8 inches in diameter and have no obstructions present,	parallel to the pipeline,	

(h) You must ensure that any trawling contractor you may use:

(1) Has no corporate or other financial ties to you; and

(2) Has a valid commercial trawling license for both the vessel and its captain.

§ 250.1742 What other methods can I use to verify that a site is clear?

If you do not trawl a site, you can verify that the site is clear of obstructions by using any of the methods shown in the following table:

If you use . . .	You must . . .	And you must . . .
(a) Sonar,	cover 100 percent of the appropriate grid area listed in § 250.1741(a),	Use a sonar signal with a frequency of at least 500 kHz.
(b) A diver,	ensure that the diver visually inspects 100 percent of the appropriate grid area listed in § 250.1741(a),	Ensure that the diver uses a search pattern of concentric circles or parallel lines spaced no more than 10 feet apart.
(c) An ROV (remotely operated vehicle),	ensure that the ROV camera records videotape over 100 percent of the appropriate grid area listed in § 250.1741(a),	Ensure that the ROV uses a pattern of concentric circles or parallel lines spaced no more than 10 feet apart.

§ 250.1743 How do I certify that a site is clear of obstructions?

(a) For a well site, you must submit to the appropriate District Manager within 30 days after you complete the verification activities a form BSEE–0124, Application for Permit to Modify, to include the following information:

(1) A signed certification that the well site area is cleared of all obstructions;

(2) The date the verification work was performed and the vessel used;

(3) The extent of the area surveyed;

(4) The survey method used;

(5) The results of the survey, including a list of any debris removed or a statement from the trawling contractor that no objects were recovered; and

(6) A post-trawling job plot or map showing the trawled area.

(b) For a platform or other facility site, you must submit the following information to the appropriate Regional Supervisor within 30 days after you complete the verification activities:

(1) A letter signed by an authorized company official certifying that the platform or other facility site area is cleared of all obstructions and that a company representative witnessed the verification activities;

(2) A letter signed by an authorized official of the company that performed the verification work for you certifying that it cleared the platform or other facility site area of all obstructions;

(3) The date the verification work was performed and the vessel used;

(4) The extent of the area surveyed;

(5) The survey method used;

(6) The results of the survey, including a list of any debris removed or a statement from the trawling contractor that no objects were recovered; and

(7) A post-trawling job plot or map showing the trawled area.

PIPELINE DECOMMISSIONING

§ 250.1750 When may I decommission a pipeline in place?

You may decommission a pipeline in place when the Regional Supervisor determines that the pipeline does not constitute a hazard (obstruction) to navigation and commercial fishing operations, unduly interfere with other uses of the OCS, or have adverse environmental effects.

§ 250.1751 How do I decommission a pipeline in place?

You must do the following to decommission a pipeline in place:

(a) Submit a pipeline decommissioning application in triplicate to the Regional Supervisor for approval. Your application must be accompanied by payment of the service fee listed in § 250.125. Your application must include the following information:

(1) Reason for the operation;

(2) Proposed decommissioning procedures;

(3) Length (feet) of segment to be decommissioned; and

(4) Length (feet) of segment remaining.

(b) Pig the pipeline, unless the Regional Supervisor determines that pigging is not practical;

(c) Flush the pipeline;

(d) Fill the pipeline with seawater;

(e) Cut and plug each end of the pipeline;

(f) Bury each end of the pipeline at least 3 feet below the seafloor or cover each end with protective concrete mats, if required by the Regional Supervisor; and

(g) Remove all pipeline valves and other fittings that could unduly interfere with other uses of the OCS.

§ 250.1752 How do I remove a pipeline?

Before removing a pipeline, you must:

(a) Submit a pipeline removal application in triplicate to the Regional Supervisor for approval. Your application must be accompanied by payment of the service fee listed in § 250.125. Your application must include the following information:

(1) Proposed removal procedures;

(2) If the Regional Supervisor requires it, a description, including anchor pattern(s), of the vessel(s) you will use to remove the pipeline;

(3) Length (feet) to be removed;

(4) Length (feet) of the segment that will remain in place;

(5) Plans for transportation of the removed pipe for disposal or salvage;

(6) Plans to protect archaeological and sensitive biological features during removal operations, including a brief assessment of the environmental impacts of the removal operations and procedures and mitigation measures that you will take to minimize such impacts; and

(7) Projected removal schedule and duration.

(b) Pig the pipeline, unless the Regional Supervisor determines that pigging is not practical; and

(c) Flush the pipeline.

§ 250.1753 After I decommission a pipeline, what information must I submit?

Within 30 days after you decommission a pipeline, you must submit a written report to the Regional Supervisor that includes the following:

(a) A summary of the decommissioning operation including the date it was completed;

(b) A description of any mitigation measures you took; and

(c) A statement signed by your authorized representative that certifies that the pipeline was decommissioned according to the approved application.

§ 250.1754 When must I remove a pipeline decommissioned in place?

You must remove a pipeline decommissioned in place if the Regional Supervisor determines that the pipeline is an obstruction.

Subpart R [Reserved]

Subpart S—Safety and Environmental Management Systems (SEMS)

§ 250.1900 Must I have a SEMS program?

You must develop, implement, and maintain a safety and environmental management system (SEMS) program. Your SEMS program must address the elements described in § 250.1902, American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75) (as incorporated by reference in § 250.198), and other requirements as identified in this subpart.

(a) If there are any conflicts between the requirements of this subpart and API RP 75; COS–2–01, COS–2–03, or COS–2–04; or ISO/IEC 17011 (incorporated by

reference as specified in § 250.198), you must follow the requirements of this subpart.

(b) Nothing in this subpart affects safety or other matters under the jurisdiction of the Coast Guard.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

§ 250.1901 What is the goal of my SEMS program?

The goal of your SEMS program is to promote safety and environmental protection by ensuring all personnel aboard a facility are complying with the policies and procedures identified in your SEMS.

(a) To accomplish this goal, you must ensure that your SEMS program identifies, addresses, and manages safety, environmental hazards, and impacts during the design, construction, start-up, operation (including, but not limited to, drilling and decommissioning), inspection, and maintenance of all new and existing facilities, including mobile offshore drilling units (MODUs) when attached to the seabed and Department of the Interior (DOI) regulated pipelines.

(b) All personnel involved with your SEMS program must be trained to have the skills and knowledge to perform their assigned duties.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

§ 250.1902 What must I include in my SEMS program?

You must have a properly documented SEMS program in place and make it available to BSEE upon request as required by § 250.1924(b).

(a) Your SEMS program must meet the minimum criteria outlined in this subpart, including the following SEMS program elements:

(1) General (see § 250.1909)

(2) Safety and Environmental Information (see § 250.1910)

(3) Hazards Analysis (see § 250.1911)

(4) Management of Change (see § 250.1912)

(5) Operating Procedures (see § 250.1913)

(6) Safe Work Practices (see § 250.1914)

(7) Training (see § 250.1915)

(8) Mechanical Integrity (Assurance of Quality and Mechanical Integrity of Critical Equipment) (see § 250.1916)

(9) Pre-startup Review (see § 250.1917)

(10) Emergency Response and Control (see § 250.1918)

(11) Investigation of Incidents (see § 250.1919)

(12) Auditing (Audit of Safety and Environmental Management Program Elements) (*see* § 250.1920)

(13) Recordkeeping (Records and Documentation) and additional BSEE requirements (*see* § 250.1928)

(14) Stop Work Authority (SWA) (see § 250.1930)

(15) Ultimate Work Authority (UWA) (see § 250.1931)

(16) Employee Participation Plan (EPP) (see § 250.1932)

(17) Reporting Unsafe Working Conditions (see § 250.1933).

(b) You must include a job safety analysis (JSA) for OCS activities identified or discussed in your SEMS program (see § 250.1911).

(c) Your SEMS program must meet or exceed the standards of safety and environmental protection of API RP 75 (as incorporated by reference in § 250.198).

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

§ 250.1903 Acronyms and definitions.

Definitions listed in this section apply to this subpart and supersede definitions in API RP 75, Appendices D and E; COS–2–01, COS–2–03, and COS–2–04; and ISO/IEC 17011 (incorporated by reference as specified in § 250.198).

(a) *Acronyms* used frequently in this subpart have the following meanings:

AB means Accreditation Body,

ASP means Audit Service Provider,

CAP means Corrective Action Plan,

COS means Center for Offshore Safety,

EPP means Employee Participation Plan,

ISO means International Organization for Standardization,

JSA means Job Safety Analysis,

MODU means Mobile Offshore Drilling Unit,

OCS means Outer Continental Shelf,

SEMS means Safety and Environmental Management Systems,

SWA means Stop Work Authority,

USCG means United States Coast Guard, and

UWA means Ultimate Work Authority.

(b) *Terms* used in this subpart are listed alphabetically as follows:

Accreditation Body (AB) means a BSEE-approved independent third-party organization that assesses and accredits ASPs.

Audit Service Provider (ASP) means an independent third-party organization that demonstrates competence to conduct SEMS audits in accordance with the requirements of this subpart.

Corrective Action Plan (CAP) means a scheduled plan to correct deficiencies identified during an audit and that is developed by an operator following the issuance of an audit report.

Personnel means direct employee(s) of the operator and contracted workers.

Ultimate Work Authority (UWA) means the authority assigned to an individual or position to make final decisions relating to activities and operations on the facility.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

§ 250.1904 Special instructions.

(a) For purposes of this subpart, each and every reference in COS–2–01, COS–2–03, and COS–2–04 (incorporated by reference as specified in § 250.198) to the term *deepwater* means the entire OCS, including all water depths.

(b) The BSEE does not incorporate by reference any requirement that you must be a COS member company. For purposes of this subpart, each and every reference in COS–2–01, COS–2–03, and COS–2–04 to the phrase *COS member company(ies)* means you, whether or not you are a COS member.

(c) For purposes of this subpart, each and every reference in the relevant sections of COS–2–01, COS–2–03, and COS–2–04 (incorporated by reference as specified in § 250.198) to the *Center for Offshore Safety* or *COS* means *accreditation body* or *AB*.

(d) For purposes of this subpart, each and every reference in ISO/IEC 17011 (incorporated by reference as specified in § 250.198) to *conformity assessment body (CAB)* means *ASP*.

[78 FR 20441, Apr. 5, 2013]

§§ 250.1905–250.1908 [Reserved]

§ 250.1909 What are management's general responsibilities for the SEMS program?

You, through your management, must require that the program elements discussed in API RP 75 (as incorporated by reference in § 250.198) and in this subpart are properly documented and are available at field and office locations, as appropriate for each program element. You, through your management, are responsible for the development, support, continued improvement, and overall success of your SEMS program. Specifically you, through your management, must:

(a) Establish goals and performance measures, demand accountability for implementation, and provide necessary resources for carrying out an effective SEMS program.

(b) Appoint management representatives who are responsible for establishing, implementing and maintaining an effective SEMS program.

(c) Designate specific management representatives who are responsible for reporting to management on the performance of the SEMS program.

(d) At intervals specified in the SEMS program and at least annually, review the SEMS program to determine if it continues to be suitable, adequate and effective (by addressing the possible need for changes to policy, objectives, and other elements of the program in light of program audit results, changing circumstances and the commitment to continual improvement) and document the observations, conclusions and recommendations of that review.

(e) Develop and endorse a written description of your safety and environmental policies and organizational structure that define responsibilities, authorities, and lines of communication required to implement the SEMS program.

(f) Utilize personnel with expertise in identifying safety hazards, environmental impacts, optimizing operations, developing safe work practices, developing training programs and investigating incidents.

(g) Ensure that facilities are designed, constructed, maintained, monitored, and operated in a manner compatible with applicable industry codes, consensus standards, and generally accepted practice as well as in compliance with all applicable governmental regulations.

(h) Ensure that management of safety hazards and environmental impacts is an integral part of the design, construction, maintenance, operation, and monitoring of each facility.

(i) Ensure that suitably trained and qualified personnel are employed to carry out all aspects of the SEMS program.

(j) Ensure that the SEMS program is maintained and kept up to date by means of periodic audits to ensure effective performance.

§ 250.1910 What safety and environmental information is required?

(a) You must require that SEMS program safety and environmental information be developed and maintained for any facility that is subject to the SEMS program.

(b) SEMS program safety and environmental information must include:

(1) Information that provides the basis for implementing all SEMS program elements, including the requirements of hazard analysis (§ 250.1911);

(2) process design information including, as appropriate, a simplified process flow diagram and acceptable upper and lower limits, where applicable, for items such as temperature, pressure, flow and composition; and

(3) mechanical design information including, as appropriate, piping and instrument diagrams; electrical area classifications; equipment arrangement drawings; design basis of the relief system; description of alarm, shutdown, and interlock systems; description of well control systems; and design basis for passive and active fire protection features and systems and emergency evacuation procedures.

§ 250.1911 What hazards analysis criteria must my SEMS program meet?

You must ensure that a hazards analysis (facility level) and a JSA (operations/task level) are developed and implemented for all of your facilities and activities identified or discussed in your SEMS. You must document and maintain a current analysis for each operation covered by this section for the life of the operation at the facility. You must update the analysis when an internal audit is conducted to ensure that it is consistent with your facility's current operations.

(a) *Hazards analysis (facility level).* The hazards analysis must be appropriate for the complexity of the operation and must identify, evaluate, and manage the hazards involved in the operation.

(1) The hazards analysis must address the following:

(i) Hazards of the operation;

(ii) Previous incidents related to the operation you are evaluating, including any incident in which you were issued an Incident of Noncompliance or a civil or criminal penalty;

(iii) Control technology applicable to the operation your hazards analysis is evaluating; and

(iv) A qualitative evaluation of the possible safety and health effects on employees, and potential impacts to the human and marine environments, which may result if the control technology fails.

(2) The hazards analysis must be performed by a person(s) with experience in the operations being evaluated. These individuals also need to be experienced in the hazards analysis methodologies being employed.

(3) You should assure that the recommendations in the hazards analysis are resolved and that the resolution is documented.

(4) A single hazards analysis can be performed to fulfill the requirements for simple and nearly identical facilities, such as well jackets and single well caissons. You can apply this single hazards analysis to simple and nearly identical facilities after you verify that any site-specific deviations are addressed in each of your SEMS program elements.

(b) *JSA.* You must ensure a JSA is prepared, conducted, and approved for OCS activities that are identified or discussed in your SEMS program. The JSA is a technique used to identify risks to personnel associated with their job activities. The JSAs are also used

to determine the appropriate mitigation measures needed to reduce job risks to personnel. The JSA must include all personnel involved with the job activity.

(1) You must ensure that your JSA identifies, analyzes, and records:

(i) The steps involved in performing a specific job;

(ii) The existing or potential safety, health, and environmental hazards associated with each step; and

(iii) The recommended action(s) and/or procedure(s) that will eliminate or reduce these hazards, the risk of a workplace injury or illness, or environmental impacts.

(2) The immediate supervisor of the crew performing the job onsite must conduct the JSA, sign the JSA, and ensure that all personnel participating in the job understand and sign the JSA.

(3) The individual you designate as being in charge of the facility must approve and sign all JSAs before personnel start the job.

(4) If a particular job is conducted on a recurring basis, and if the parameters of these recurring jobs do not change, then the person in charge of the job may decide that a JSA for each individual job is not required. The parameters you must consider in making this determination include, but are not limited to, changes in personnel, procedures, equipment, and environmental conditions associated with the job.

(c) All personnel, which includes contractors, must be trained in accordance with the requirements of § 250.1915. You must also verify that contractors are trained in accordance with § 250.1915 prior to performing a job.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

§ 250.1912 What criteria for management of change must my SEMS program meet?

(a) You must develop and implement written management of change procedures for modifications associated with the following:

(1) Equipment,

(2) Operating procedures,

(3) Personnel changes (including contractors),

(4) Materials, and

(5) Operating conditions.

(b) Management of change procedures do not apply to situations involving replacement in kind (such as, replacement of one component by another component with the same performance capabilities).

(c) You must review all changes prior to their implementation.

(d) The following items must be included in your management of change procedures:

(1) The technical basis for the change;

(2) Impact of the change on safety, health, and the coastal and marine environments;

(3) Necessary time period to implement the change; and

(4) Management approval procedures for the change.

(e) Employees, including contractors whose job tasks will be affected by a change in the operation, must be informed of, and trained in, the change prior to startup of the process or affected part of the operation; and

(f) If a management of change results in a change in the operating procedures of your SEMS program, such changes must be documented and dated.

§ 250.1913 What criteria for operating procedures must my SEMS program meet?

(a) You must develop and implement written operating procedures that provide instructions for conducting safe and environmentally sound activities involved in each operation addressed in your SEMS program. These procedures must include the job title and reporting relationship of the person or persons responsible for each of the facility's operating areas and address the following:

(1) Initial startup;

(2) Normal operations;

(3) All emergency operations (including but not limited to medical evacuations, weather-related evacuations and emergency shutdown operations);

(4) Normal shutdown;

(5) Startup following a turnaround, or after an emergency shutdown;

(6) Bypassing and flagging out-of-service equipment;

(7) Safety and environmental consequences of deviating from your equipment operating limits and steps

required to correct or avoid this deviation;

(8) Properties of, and hazards presented by, the chemicals used in the operations;

(9) Precautions you will take to prevent the exposure of chemicals used in your operations to personnel and the environment. The precautions must include control technology, personal protective equipment, and measures to be taken if physical contact or airborne exposure occurs;

(10) Raw materials used in your operations and the quality control procedures you used in purchasing these raw materials;

(11) Control of hazardous chemical inventory; and

(12) Impacts to the human and marine environment identified through your hazards analysis.

(b) Operating procedures must be accessible to all employees involved in the operations.

(c) Operating procedures must be reviewed at the conclusion of specified periods and as often as necessary to assure they reflect current and actual operating practices, including any changes made to your operations.

(d) You must develop and implement safe and environmentally sound work practices for identified hazards during operations and the degree of hazard presented.

(e) Review of and changes to the procedures must be documented and communicated to responsible personnel.

§ 250.1914 What criteria must be documented in my SEMS program for safe work practices and contractor selection?

Your SEMS program must establish and implement safe work practices designed to minimize the risks associated with operations, maintenance, modification activities, and the handling of materials and substances that could affect safety or the environment. Your SEMS program must also document contractor selection criteria. When selecting a contractor, you must obtain and evaluate information regarding the contractor's safety record and environmental performance. You must ensure that contractors have their own written safe work practices. Contractors may adopt appropriate sections of your SEMS program. You and your contractor must document an agreement on appropriate contractor safety and environmental policies and practices before the contractor begins work at your facilities.

(a) A contractor is anyone performing work for you. However, these requirements do not apply to contractors providing domestic services to you or other contractors. Domestic services include janitorial work, food and beverage service, laundry service, housekeeping, and similar activities.

(b) You must document that your contracted employees are knowledgeable and experienced in the work practices necessary to perform their job in a safe and environmentally sound manner. Documentation of each contracted employee's expertise to perform his/her job and a copy of the contractor's safety policies and procedures must be made available to the operator and BSEE upon request.

(c) Your SEMS program must include procedures and verification for selecting a contractor as follows:

(1) Your SEMS program must have procedures that verify that contractors are conducting their activities in accordance with your SEMS program.

(2) You are responsible for making certain that contractors have the skills and knowledge to perform their assigned duties and are conducting these activities in accordance with the requirements in your SEMS program.

(3) You must make the results of your verification for selecting contractors available to BSEE upon request.

(d) Your SEMS program must include procedures and verification that contractor personnel understand and can perform their assigned duties for activities such as, but not limited to:

(1) Installation, maintenance, or repair of equipment;

(2) Construction, startup, and operation of your facilities;

(3) Turnaround operations;

(4) Major renovation; or

(5) Specialty work.

(e) You must:

(1) Perform periodic evaluations of the performance of contract employees that verifies they are fulfilling their obligations, and

(2) Maintain a contractor employee injury and illness log for 2 years related to the contractor's work in the operation area, and include this information on Form BSEE–0131.

(f) You must inform your contractors of any known hazards at the facility they are working on including, but not limited to fires, explosions, slips, trips, falls, other injuries, and hazards associated with lifting operations.

(g) You must develop and implement safe work practices to control the presence, entrance, and exit of contract employees in operation areas.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

§ 250.1915 What training criteria must be in my SEMS program?

Your SEMS program must establish and implement a training program so that all personnel are trained in accordance with their duties and responsibilities to work safely and are aware of potential environmental impacts. Training must address such areas as operating procedures (§ 250.1913), safe work practices (§ 250.1914), emergency response and control measures (§ 250.1918), SWA (§ 250.1930), UWA (§ 250.1931), EPP (§ 250.1932), reporting unsafe working conditions (§ 250.1933), and how to recognize and identify hazards and how to construct and implement JSAs (§ 250.1911). You must document your instructors' qualifications. Your SEMS program must address:

(a) Initial training for the basic well-being of personnel and protection of the environment, and ensure that persons assigned to operate and maintain the facility possess the required knowledge and skills to carry out their duties and responsibilities, including startup and shutdown.

(b) Periodic training to maintain understanding of, and adherence to, the current operating procedures, using periodic drills, to verify adequate retention of the required knowledge and skills.

(c) Communication requirements to ensure that personnel will be informed of and trained as outlined in this section whenever a change is made in any of the areas in your SEMS program that impacts their ability to properly understand and perform their duties and responsibilities. Training and/or notice of the change must be given before personnel are expected to operate the facility.

(d) How you will verify that the contractors are trained in the work practices necessary to understand and perform their jobs in a safe and environmentally sound manner in accordance with all provisions of this section.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

§ 250.1916 What criteria for mechanical integrity must my SEMS program meet?

You must develop and implement written procedures that provide instructions to ensure the mechanical integrity and safe operation of equipment through inspection, testing, and quality assurance. The purpose of mechanical integrity is to ensure that equipment is fit for service. Your mechanical integrity program must encompass all equipment and systems used to prevent or mitigate uncontrolled releases of hydrocarbons, toxic substances, or other materials that may cause environmental or safety consequences. These procedures must address the following:

(a) The design, procurement, fabrication, installation, calibration, and maintenance of your equipment and systems in accordance with the manufacturer's design and material specifications.

(b) The training of each employee involved in maintaining your equipment and systems so that your employees can implement your mechanical integrity program.

(c) The frequency of inspections and tests of your equipment and systems. The frequency of inspections and tests must be in accordance with BSEE regulations and meet the manufacturer's recommendations. Inspections and tests can be performed more frequently if determined to be necessary by prior operating experience.

(d) The documentation of each inspection and test that has been performed on your equipment and systems. This documentation must identify the date of the inspection or test; include the name and position, and the signature of the person who performed

the inspection or test; include the serial number or other identifier of the equipment on which the inspection or test was performed; include a description of the inspection or test performed; and the results of the inspection test.

(e) The correction of deficiencies associated with equipment and systems that are outside the manufacturer's recommended limits. Such corrections must be made before further use of the equipment and system.

(f) The installation of new equipment and constructing systems. The procedures must address the application for which they will be used.

(g) The modification of existing equipment and systems. The procedures must ensure that they are modified for the application for which they will be used.

(h) The verification that inspections and tests are being performed. The procedures must be appropriate to ensure that equipment and systems are installed consistent with design specifications and the manufacturer's instructions.

(i) The assurance that maintenance materials, spare parts, and equipment are suitable for the applications for which they will be used.

§ 250.1917 What criteria for pre-startup review must be in my SEMS program?

Your SEMS program must require that the commissioning process include a pre-startup safety and environmental review for new and significantly modified facilities that are subject to this subpart to confirm that the following criteria are met:

(a) Construction and equipment are in accordance with applicable specifications.

(b) Safety, environmental, operating, maintenance, and emergency procedures are in place and are adequate.

(c) Safety and environmental information is current.

(d) Hazards analysis recommendations have been implemented as appropriate.

(e) Training of operating personnel has been completed.

(f) Programs to address management of change and other elements of this subpart are in place.

(g) Safe work practices are in place.

§ 250.1918 What criteria for emergency response and control must be in my SEMS program?

Your SEMS program must require that emergency response and control plans are in place and are ready for immediate implementation. These plans must be validated by drills carried out in accordance with a schedule defined by the SEMS training program (§ 250.1915). The SEMS emergency response and control plans must include:

(a) Emergency Action Plan that assigns authority and responsibility to the appropriate qualified person(s) at a facility for initiating effective emergency response and control, addressing emergency reporting and response requirements, and complying with all applicable governmental regulations;

(b) Emergency Control Center(s) designated for each facility with access to the Emergency Action Plans, oil spill contingency plan, and other safety and environmental information (§ 250.1910); and

(c) Training and Drills incorporating emergency response and evacuation procedures conducted periodically for all personnel (including contractor's personnel), as required by the SEMS training program (§ 250.1915). Drills must be based on realistic scenarios conducted periodically to exercise elements contained in the facility or area emergency action plan. An analysis and critique of each drill must be conducted to identify and correct weaknesses.

§ 250.1919 What criteria for investigation of incidents must be in my SEMS program?

To learn from incidents and help prevent similar incidents, your SEMS program must establish procedures for investigation of all incidents with serious safety or environmental consequences and require investigation of incidents that are determined by facility management or BSEE to have possessed the potential for serious safety or environmental consequences. Incident investigations must be initiated

as promptly as possible, with due regard for the necessity of securing the incident scene and protecting people and the environment. Incident investigations must be conducted by personnel knowledgeable in the process involved, investigation techniques, and other specialties that are relevant or necessary.

(a) The investigation of an incident must address the following:

(1) The nature of the incident;

(2) The factors (human or other) that contributed to the initiation of the incident and its escalation/control; and

(3) Recommended changes identified as a result of the investigation.

(b) A corrective action program must be established based on the findings of the investigation in order to analyze incidents for common root causes. The corrective action program must:

(1) Retain the findings of investigations for use in the next hazard analysis update or audit;

(2) Determine and document the response to each finding to ensure that corrective actions are completed; and

(3) Implement a system whereby conclusions of investigations are distributed to similar facilities and appropriate personnel within their organization.

§ 250.1920 What are the auditing requirements for my SEMS program?

(a) Your SEMS program must be audited by an accredited ASP according to the requirements of this subpart and API RP 75, Section 12 (incorporated by reference as specified in § 250.198). The audit process must also meet or exceed the criteria in Sections 9.1 through 9.8 of *Requirements for Third-party SEMS Auditing and Certification of Deepwater Operations* COS–2–03 (incorporated by reference as specified in § 250.198) or its equivalent. Additionally, the audit team lead must be an employee, representative, or agent of the ASP, and must not have any affiliation with the operator. The remaining team members may be chosen from your personnel and those of the ASP. The audit must be comprehensive and include all elements of your SEMS program. It must also identify safety and environmental performance deficiencies.

(b) Your audit plan and procedures must meet or exceed all of the recommendations included in API RP 75 section 12 (as specified in § 250.198) and include information on how you addressed those recommendations. You must specifically address the following items:

(1) Section 12.1 General.

(2) Section 12.2 Scope.

(3) Section 12.3 Audit Coverage.

(4) Section 12.4 Audit Plan. You must submit your written Audit Plan to BSEE at least 30 days before the audit. BSEE reserves the right to modify the list of facilities that you propose to audit.

(5) Section 12.5 Audit Frequency. You must have your SEMS program audited by an ASP within 2 years after initial implementation and every 3 years thereafter. The 3-year auditing cycle begins on the start date of each comprehensive audit (including the initial implementation audit) and ends on the start date of your next comprehensive audit. For exploratory drilling operations taking place on the Arctic OCS, you must conduct an audit, consisting of an onshore portion and an offshore portion, including all related infrastructure, once per year for every year in which drilling is conducted.

(6) Section 12.6 Audit Team. Your audits must be performed by an ASP as described in § 250.1921. You must include the ASP's qualifications in your audit plan.

(c) You must submit an audit report of the audit findings, observations, deficiencies identified, and conclusions to BSEE within 60 days of the audit completion date. For exploratory drilling operations taking place on the Arctic OCS, you must submit an audit report of the audit findings, observations, deficiencies and conclusions for the onshore portion of your audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(d) You must provide BSEE with a copy of your CAP for addressing the deficiencies identified in your audit within 60 days of the audit completion date. Your CAP must include the name and job title of the personnel responsible

for correcting the identified deficiency(ies). The BSEE will notify you as soon as practicable after receipt of your CAP if your proposed schedule is not acceptable or if the CAP does not effectively address the audit findings. For exploratory drilling operations taking place on the Arctic OCS, you must provide BSEE with a copy of your CAP for addressing deficiencies or nonconformities identified in the onshore portion of the audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(e) BSEE may verify that you undertook the corrective actions and that these actions effectively address the audit findings.

(f) For exploratory drilling operations taking place on the Arctic OCS, during the offshore portion of each audit, 100 percent of the facilities operated must be audited while drilling activities are underway. You must start and close the offshore portion of the audit for each facility within 30 days after the first spudding of the well or entry into an existing wellbore for any purpose from that facility.

(g) For exploratory drilling operations taking place on the Arctic OCS, if BSEE determines that the CAP or progress toward implementing the CAP is not satisfactory, BSEE may order you to shut down all or part of your operations.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013; 81 FR 36151, June 6, 2016; 81 FR 46563, July 15, 2016]

§ 250.1921 What qualifications must the ASP meet?

(a) The ASP must meet or exceed the qualifications, competency, and training criteria contained in Section 3 and Sections 6 through 10 of *Qualification and Competence Requirements for Audit Teams and Auditors Performing Third-party SEMS Audits of Deepwater Operations*, COS–2–01, (incorporated by reference as specified in § 250.198) or its equivalent;

(b) The ASP must be accredited by a BSEE-approved AB; and

(c) The ASP must perform an audit in accordance with 250.1920(a).

[78 FR 20442, Apr. 5, 2013]

§ 250.1922 What qualifications must an AB meet?

(a) In order for BSEE to approve an AB, the organization must satisfy the requirements of the International Organization for Standardization's (ISO/IEC 17011) *Conformity assessment—General requirements for accreditation bodies accrediting conformity assessment bodies*, First Edition 2004–09–01; Corrected Version 2005–02–15 (incorporated by reference as specified in § 250.198) or its equivalent.

(1) The AB must have an accreditation process that meets or exceeds the requirements contained in Section 6 of *Requirements for Accreditation of Audit Service Providers Performing SEMS Audits and Certification of Deepwater Operations*, COS–2–04 (incorporated by reference as specified in § 250.198) or its equivalent, and other requirements specified in this subpart. Organizations requesting approval must submit documentation to BSEE describing the process for assessing an ASP for accreditation and approving, maintaining, and withdrawing the accreditation of an ASP. Requests for approval must be sent to DOI/BSEE, ATTN: Chief, Office of Offshore Regulatory Programs, 381 Elden Street, HE–3314, Herndon, VA 20170.

(2) An AB may be subject to BSEE audits and other requirements deemed necessary to verify compliance with the accreditation requirements.

(b) An AB must have procedures in place to avoid conflicts of interest with the ASP and make such information available to BSEE upon request.

[78 FR 20442, Apr. 5, 2013]

§ 250.1923 [Reserved]

§ 250.1924 How will BSEE determine if my SEMS program is effective?

(a) The BSEE, or its authorized representative, may evaluate or visit your facility(ies) to determine whether your SEMS program is in place, addresses all required elements, is effective in protecting worker safety and health and the environment, and preventing incidents. The BSEE, or its authorized representative, may evaluate any and all aspects of your SEMS program as outlined in this subpart. These evaluations or visits may be random and may

be based upon your performance or that of your contractors.

(b) For the evaluations, you must make the following available to BSEE upon request:

(1) Your SEMS program;

(2) Your audit team's qualifications;

(3) The SEMS audits conducted of your program;

(4) Documents or information relevant to whether you have addressed and corrected the deficiencies of your audit; and

(5) Other relevant documents or information.

(c) During the site visit BSEE may verify that:

(1) Personnel are following your SEMS program,

(2) You can explain and demonstrate the procedures and policies included in your SEMS program; and

(3) You can produce evidence to support the implementation of your SEMS program.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013]

§ 250.1925 May BSEE direct me to conduct additional audits?

(a) The BSEE may direct you to have an ASP audit of your SEMS program if BSEE identifies safety or non-compliance concerns based on the results of our inspections and evaluations, or as a result of an event. This BSEE-directed audit is in addition to the regular audit required by § 250.1920. Alternatively, BSEE may conduct an audit.

(1) If BSEE directs you to have an ASP audit, you are responsible for all of the costs associated with the audit, and

(i) The ASP must meet the requirements of §§ 250.1920 and 250.1921 of this subpart.

(ii) You must submit an audit report of the audit findings, observations, deficiencies identified, and conclusions to BSEE within 60 days of the audit completion date.

(2) If BSEE conducts the audit, BSEE will provide you with a report of the audit findings, observations, deficiencies identified, and conclusions as soon as practicable.

(b) You must provide BSEE a copy of your CAP for addressing the deficiencies identified in the BSEE-directed audit within 60 days of the audit completion date. Your CAP must include the name and job title of the personnel responsible for correcting the identified deficiency(ies). The BSEE will notify you as soon as practicable after receipt of your CAP if your proposed schedule is not acceptable or if the CAP does not effectively address the audit findings.

[78 FR 20442, Apr. 5, 2013]

§ 250.1926 [Reserved]

§ 250.1927 What happens if BSEE finds shortcomings in my SEMS program?

If BSEE determines that your SEMS program is not in compliance with this subpart we may initiate one or more of the following enforcement actions:

(a) Issue an Incident(s) of Noncompliance;

(b) Assess civil penalties; or

(c) Initiate probationary or disqualification procedures from serving as an OCS operator.

§ 250.1928 What are my recordkeeping and documentation requirements?

(a) Your SEMS program procedures must ensure that records and documents are maintained for a period of 6 years, except as provided below. You must document and keep all SEMS audits for 6 years and make them available to BSEE upon request. You must maintain a copy of all SEMS program documents at an onshore location.

(b) For JSAs, the person in charge of the job must document the results of the JSA in writing and must ensure that records are kept onsite for 30 days. In the case of a MODU, records must be kept onsite for 30 days or until you release the MODU, whichever comes first. You must retain these records for 2 years and make them available to BSEE upon request.

(c) You must document and date all management of change provisions as specified in § 250.1912. You must retain these records for 2 years and make them available to BSEE upon request.

(d) You must keep your injury/illness log for 2 years and make them available to BSEE upon request.

(e) You must keep all evaluations completed on contractor's safety policies and procedures for 2 years and make them available to BSEE upon request.

(f) For SWA, you must document all training and reviews required by § 250.1930(e). You must ensure that these records are kept onsite for 30 days. In the case of a MODU, records must be kept onsite for 30 days or until you release the MODU, whichever comes first. You must retain these records for 2 years and make them available to BSEE upon request.

(g) For EPP, you must document your employees' participation in the development and implementation of the SEMS program. You must retain these records for 2 years and make them available to BSEE upon request.

(h) You must keep all records in an orderly manner, readily identifiable, retrievable and legible, and include the date of any and all revisions.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013]

§ 250.1929 What are my responsibilities for submitting OCS performance measure data?

You must submit Form BSEE–0131 on an annual basis by March 31st. The form must be broken down quarterly, reporting the previous calendar year's data.

§ 250.1930 What must be included in my SEMS program for SWA?

(a) Your SWA procedures must ensure the capability to immediately stop work that is creating imminent risk or danger. These procedures must grant all personnel the responsibility and authority, without fear of reprisal, to stop work or decline to perform an assigned task when an imminent risk or danger exists. Imminent risk or danger means any condition, activity, or practice in the workplace that could reasonably be expected to cause:

(1) Death or serious physical harm; or

(2) Significant environmental harm to:

(i) Land;

(ii) Air; or

(iii) Mineral deposits, marine, coastal, or human environment.

(b) The person in charge of the conducted work is responsible for ensuring the work is stopped in an orderly and safe manner. Individuals who receive a notification to stop work must comply with that direction immediately.

(c) Work may be resumed when the individual on the facility with UWA determines that the imminent risk or danger does not exist or no longer exists. The decision to resume activities must be documented in writing as soon as practicable.

(d) You must include SWA procedures and expectations as a standard statement in all JSAs.

(e) You must conduct training on your SWA procedures as part of orientations for all new personnel who perform activities on the OCS. Additionally, the SWA procedures must be reviewed during all meetings focusing on safety on facilities subject to this subpart.

[78 FR 20443, Apr. 5, 2013]

§ 250.1931 What must be included in my SEMS program for UWA?

(a) Your SEMS program must have a process to identify the individual with the UWA on your facility(ies). You must designate this individual taking into account all applicable USCG regulations that deal with designating a person in charge of an OCS facility. Your SEMS program must clearly define who is in charge at all times. In the event that multiple facilities, including a MODU, are attached and working together or in close proximity to one another to perform an OCS operation, your SEMS program must identify the individual with the UWA over the entire operation, including all facilities.

(b) You must ensure that all personnel clearly know who has UWA and who is in charge of a specific operation or activity at all times, including when that responsibility shifts to a different individual.

(c) The SEMS program must provide that if an emergency occurs that creates an imminent risk or danger to the health or safety of an individual, the public, or to the environment (as specified in § 250.1930(a)), the individual with the UWA is authorized to pursue the most effective action necessary in that

individual's judgment for mitigating and abating the conditions or practices causing the emergency.

[78 FR 20443, Apr. 5, 2013]

§250.1932 What are my EPP requirements?

(a) Your management must consult with their employees on the development, implementation, and modification of your SEMS program.

(b) Your management must develop a written plan of action regarding how your appropriate employees, in both your offices and those working on offshore facilities, will participate in your SEMS program development and implementation.

(c) Your management must ensure that employees have access to sections of your SEMS program that are relevant to their jobs.

[78 FR 20443, Apr. 5, 2013]

§250.1933 What procedures must be included for reporting unsafe working conditions?

(a) Your SEMS program must include procedures for all personnel to report unsafe working conditions in accordance with §250.193. These procedures must take into account applicable USCG reporting requirements for unsafe working conditions.

(b) You must post a notice at the place of employment in a visible location frequently visited by personnel that contains the reporting information in §250.193.

[78 FR 20443, Apr. 5, 2013]

PART 251—GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

Sec.
251.1 Definitions.
251.2 [Reserved]
251.3 Authority and applicability of this part.
251.4–251.6 [Reserved]
251.7 Test drilling activities under a permit.
251.8–251.14 [Reserved]
251.15 Authority for information collection.

AUTHORITY: 31 U.S.C. 9701, 43 U.S.C. 1334.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

§251.1 Definitions.

Terms used in this part have the following meaning:

Act means the Outer Continental Shelf Lands Act (OCSLA), as amended (43 U.S.C. 1331 *et seq.*).

Analyzed geological information means data collected under a permit or a lease that 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 from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

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.

Archaeological resources mean any material remains of human life or activities that are at least 50 years of age and of archaeological interest.

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors that 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 shorelines of the several coastal States and extends seaward to the outer limit of the U.S. territorial sea.

Coastal Zone Management Act means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 *et seq.*).

Data means facts, statistics, measurements, or samples that have not been analyzed, processed, or interpreted.

Deep stratigraphic test means drilling that involves the penetration into the sea bottom of more than 500 feet (152 meters).

Director means the Director of the Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, or a subordinate authorized to act on the Director's behalf.

Exploration means the commercial search for oil, gas, and sulphur. Activities classified as exploration include, but are not limited to:

(1) Geological and geophysical marine and airborne surveys where magnetic, gravity, seismic reflection, seismic refraction, gas sniffers, coring, or other systems are used to detect or imply the presence of oil, gas, or sulphur; and

(2) Any drilling, whether on or off a geological structure.

Geological and geophysical scientific research means any oil, gas, or sulphur related investigation conducted in the OCS for scientific and/or research purposes. Geological, geophysical, and geochemical data and information gathered and analyzed are made available to the public for inspection and reproduction at the earliest practicable time. The term does not include commercial geological or geophysical exploration or research.

Geological exploration means exploration that uses geological and geochemical techniques (e.g., coring and test drilling, well logging, and bottom sampling) to produce data and information on oil, gas, and sulphur resources in support of possible exploration and development activities. The term does not include geological scientific research.

Geological information means geological or geochemical data that have been analyzed, processed, or interpreted.

Geophysical data means measurements that have not been processed or interpreted.

Geophysical exploration means exploration that utilizes geophysical techniques (e.g., gravity, magnetic, electromagnetic, or seismic) to produce data and information on oil, gas, and sulphur resources in support of possible exploration and development activities. The term does not include geophysical scientific research.

Geophysical information means geophysical data that have been processed or interpreted.

Governor means the Governor of a State or the person or entity lawfully designated to exercise the powers granted to a 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.

Hydrocarbon occurrence 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.

Interpreted geological information means knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geological data and analyzed and processed geologic information.

Interpreted geophysical information means knowledge, often in the form of seismic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

Lease means an agreement 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.

Lessee means a person who has entered into, or is the BOEM approved assignee of, a lease with the United States to explore for, develop, and produce the leased minerals. The term ''lessee'' also includes an owner of operating rights.

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the quality of the marine ecosystem in the coastal zone and in the OCS.

Material remains mean physical evidence of human habitation, occupation, use, or activity, including the site, location, or context in which such evidence is situated.

Minerals mean 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).

Notice means a written statement of intent to conduct geological or geophysical scientific research related to oil, gas, and sulphur in the OCS other than under a permit.

Oil, gas, and sulphur mean oil, gas, sulphur, geopressured-geothermal, and associated resources.

Outer Continental Shelf (OCS) means all submerged lands lying 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.

Permit means the contract or agreement, other than a lease, issued pursuant to this part, under which a person acquires the right to conduct on the OCS, in accordance with appropriate statutes, regulations, and stipulations:

(1) Geological exploration for mineral resources;

(2) Geophysical exploration for mineral resources;

(3) Geological scientific research; or

(4) Geophysical scientific research.

Permittee means the person authorized by a permit issued pursuant to this part to conduct activities on the OCS.

Person means a citizen or national of the United States; an alien lawfully admitted for permanent residence in the United States as defined in section 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 or anyone operating in a manner provided for by treaty or other applicable international agreements. The term does not include Federal agencies.

Processed geological or geophysical information means data collected under a permit and later processed or reprocessed. 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. Reprocessing is the additional processing other than ordinary processing used in the general course of evaluation. Reprocessing operations may include varying identified parameters for the detailed study of a specific problem area. Reprocessing may occur several years after the original processing date. Reprocessing is determined to be completed on the date that the reprocessed information is first available in a useable format for in-house interpretation by BOEM or the permittee, or becomes first available to third parties via sale, trade, license agreement, or other means.

Secretary means the Secretary of the Interior or a subordinate authorized to act on the Secretary's behalf.

Shallow test drilling means drilling into the sea bottom to depths less than those specified in the definition of a deep stratigraphic test.

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.

Third Party means any person other than the permittee or a representative of the United States, including all persons who obtain data or information acquired under a permit from the permittee, or from another third party, by sale, trade, license agreement, or other means.

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 under the Act.

You means a person who applies for and/or obtains a permit, or files a Notice to conduct geological or geophysical exploration or scientific research related to oil, gas, and sulphur in the OCS.

§ 251.2 [Reserved]

§ 251.3 Authority and applicability of this part.

BSEE authorizes you to conduct exploration or scientific research activities under this part in accordance with the Act, the regulations in this part, orders of the Director/Regional Director, and other applicable statutes, regulations, and amendments.

(a) This part does not apply to G&G exploration conducted by or on behalf of the lessee on a lease in the OCS. Refer to 30 CFR part 550 if you plan to conduct G&G activities related to oil, gas, or sulphur under terms of a lease.

(b) Federal agencies are exempt from the regulations in this part.

(c) G&G exploration or G&G scientific research related to minerals other than oil, gas, and sulphur is covered by regulations at 30 CFR part 580.

§§ 251.4–251.6 [Reserved]

§ 251.7 Test drilling activities under a permit.

(a) [Reserved]

(b) *Deep stratigraphic tests.* You must submit to the appropriate BOEM or BSEE Regional Director, at the address in 30 CFR 551.5(d) for BOEM or 30 CFR 254.7 for BSEE, a drilling plan (submitted to BOEM), an environmental report (submitted to BOEM), an Application for Permit to Drill (Form BSEE–0123) (submitted to BSEE), and a Supplemental APD Information Sheet (Form BSEE–0123S) (submitted to BSEE) as follows:

(1) *Drilling plan.* The drilling plan must include:

(i) The proposed type, sequence, and timetable of drilling activities;

(ii) A description of your drilling rig, indicating the important features with special attention to safety, pollution prevention, oil-spill containment and cleanup plans, and onshore disposal procedures;

(iii) The location of each deep stratigraphic test you will conduct, including the location of the surface and projected bottomhole of the borehole;

(iv) The types of geological and geophysical survey instruments you will use before and during drilling;

(v) Seismic, bathymetric, sidescan sonar, magnetometer, or other geophysical data and information 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; and

(vi) Other relevant data and information that the BOEM Regional Director requires.

(2) *Environmental report.* The environmental report must include all of the following material:

(i) A summary with data and information available at the time you submitted the related drilling plan. BOEM will consider site-specific data and information developed since the most recent environmental impact statement or other environmental impact analysis in the immediate area. The summary must meet the following requirements:

(A) You must concentrate on the issues specific to the site(s) of drilling activity. However, you only need to summarize data and information discussed in any environmental reports, analyses, or impact statements prepared for the geographic area of the drilling activity.

(B) You must list referenced material. Include brief descriptions and a statement of where the material is available for inspection.

(C) You must refer only to data that are available to BOEM.

(ii) Details about your project such as:

(A) A list and description of new or unusual technologies;

(B) The location of travel routes for supplies and personnel;

(C) The kinds and approximate levels of energy sources;

(D) The environmental monitoring systems; and

(E) Suitable maps and diagrams showing details of the proposed project layout.

(iii) A description of the existing environment. For this section, you must

include the following information on the area:

(A) Geology;

(B) Physical oceanography;

(C) Other uses of the area;

(D) Flora and fauna;

(E) Existing environmental monitoring systems; and

(F) Other unusual or unique characteristics that may affect or be affected by the drilling activities.

(iv) A description of the probable impacts of the proposed action on the environment and the measures you propose for mitigating these impacts.

(v) A description of any unavoidable or irreversible adverse effects on the environment that could occur.

(vi) Other relevant data that the BOEM Regional Director requires.

(3) *Copies for coastal States.* You must submit copies of the drilling plan and environmental report to the BOEM Regional Director for transmittal to the Governor of each affected coastal State and the coastal zone management agency of each affected coastal State that has an approved program under the Coastal Zone Management Act. (The BOEM Regional Director will make the drilling plan and environmental report available to appropriate Federal agencies and the public according to the Department of the Interior's policies and procedures).

(4) *Certification of coastal zone management program consistency and State concurrence.* When required under an approved coastal zone management program of an affected State, your drilling plan must include a certification that the proposed activities described in the plan comply with enforceable policies of, and will be conducted in a manner consistent with such State's program. The BOEM Regional Director may not approve any of the activities described in the drilling plan unless the State concurs with the consistency certification or the Secretary of Commerce makes the finding authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act.

(5) *Protecting archaeological resources.* If the BOEM Regional Director believes that an archaeological resource may exist in the area that may be affected by drilling, the BOEM Regional Director will notify you of the need to prepare an archaeological report under 30 CFR 551.7(b)(5).

(i) If the evidence suggests that an archaeological resource may be present, you must:

(A) Locate the site of the drilling so as to not adversely affect the area where the archaeological resources may be, or

(B) Establish to the satisfaction of the BOEM Regional Director that an archaeological resource does not exist or will not be adversely affected by drilling. This must 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 must be submitted to the BOEM Regional Director for review.

(ii) If the BOEM Regional Director determines that an archaeological resource is likely to be present in the area that may be affected by drilling, and may be adversely affected by drilling, the BOEM Regional Director will notify you immediately. You must take no action that may adversely affect the archaeological resource unless further investigations determine that the resource is not archaeologically significant.

(iii) If you discover any archaeological resource while drilling, you must immediately halt drilling and report the discovery to the BOEM Regional Director. If investigations determine that the resource is significant, the BOEM Regional Director will inform you how to protect it.

(6) *Application for permit to drill (APD).* Before commencing deep stratigraphic test drilling activities under an approved drilling plan, you must submit an APD and a Supplemental APD Information Sheet (Forms BSEE–0123 and BSEE–0123S) and receive approval. You must comply with all regulations relating to drilling operations in 30 CFR part 250.

(7) *Revising an approved drilling plan.* Before you revise an approved drilling plan, you must obtain the BOEM Regional Director's approval.

(8) *After drilling.* When you complete the test activities, you must permanently plug and abandon the boreholes

of all deep stratigraphic tests in compliance with 30 CFR part 250. If the tract on which you conducted a deep stratigraphic test is leased to another party for exploration and development, and if the lessee has not disturbed the borehole, BSEE will hold you and not the lessee responsible for problems associated with the test hole.

(9) *Deadline for completing a deep stratigraphic test.* If your deep stratigraphic test well is within 50 geographic miles of a tract that BOEM has identified for a future lease sale, as listed on the currently approved OCS leasing schedule, you must complete all drilling activities and submit the data and information to the BOEM Regional Director at least 60 days before the first day of the month in which BOEM schedules the lease sale. However, the BOEM Regional Director may extend your permit duration to allow you to complete drilling activities and submit data and information if the extension is in the National interest.

(c)–(d) [Reserved]

§§ 251.8–251.14 [Reserved]

§ 251.15 Authority for information collection.

The Office of Management and Budget has approved the information collection requirements in this part under 44 U.S.C. 3501 *et seq.* and assigned OMB control number 1014–0025 as it pertains to Application for Permit to Drill (APD, Form BSEE–0123), and Supplemental APD Information Sheet (Form BSEE–0123S). The title of this information collection is ''30 CFR Part 250, *Application for Permit to Drill (APD, Revised APD) Supplemental APD Information Sheet, and all supporting documents.*''

[81 FR 36151, June 6, 2016]

PART 252—OUTER CONTINENTAL SHELF (OCS) OIL AND GAS INFORMATION PROGRAM

Sec.

252.1 Purpose.
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: 76 FR 64462, Oct. 18, 2011, 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 30 CFR parts 250, 251, 550, and 551 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, Bureau of Safety and Environmental Enforcement (BSEE). 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 following meanings:

Act refers to the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

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.

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 oil spill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

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.

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.

Data means facts and statistics or samples which have not been analyzed or processed.

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.

Director means the Director of the Bureau of Safety and Environmental Enforcement (BSEE) of the U.S. Department of the Interior or a designee of the Director.

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.

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.

Information, when used without a qualifying adjective, includes analyzed 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, oil or natural gas, or the land covered by such authorization, whichever is required by the context.

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 30 CFR part 550, including all parties holding such authority by or through the lessee.

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.

Permittee means the party authorized by a permit issued pursuant to 30 CFR parts 251 and 551 to conduct activities on the OCS.

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.

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.

Secretary means the Secretary of the Interior or a designee of the Secretary.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36151, June 6, 2016]

§ 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 BSEE 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.

§ 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 BSEE 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 BOEM Director shall prepare an index of OCS information (see 30 CFR 556.10). 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 BOEM, 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.

§ 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 parts 250 and 550 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf) and 30 CFR parts 251 and 551 (Geological and Geophysical Explorations of the Outer Continental Shelf).

(b) Except as provided in § 252.7 or in 30 CFR parts 250, 251, 550, and 551, 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 250.197, 30 CFR 550.197, and 30 CFR 551.14, 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 250.197, 30 CFR 550.197, and 30 CFR 551.14, 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 parts 250 and 550 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations contained in 30 CFR parts 251 and 551 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in 30 CFR parts 252 and 552 (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 253 [RESERVED]

PART 254—OIL-SPILL RESPONSE REQUIREMENTS FOR FACILITIES LOCATED SEAWARD OF THE COAST LINE

Subpart A—General

Sec.
254.1 Who must submit an oil spill response plan (OSRP)?
254.2 When must I submit an OSRP?
254.3 May I cover more than one facility in my OSRP?
254.4 May I reference other documents in my OSRP?
254.5 General response plan requirements.
254.6 Definitions.
254.7 How do I submit my OSRP to the BSEE?
254.8 May I appeal decisions under this part?
254.9 Authority for information collection.

Subpart B—Oil-Spill Response Plans for Outer Continental Shelf Facilities

254.20 Purpose.
254.21 How must I format my OSRP?
254.22 What information must I include in the ''Introduction and OSRP contents'' section?
254.23 What information must I include in the ''Emergency response action plan'' section?
254.24 What information must I include in the ''Equipment inventory'' appendix?
254.25 What information must I include in the ''Contractual agreements'' appendix?
254.26 What information must I include in the ''Worst case discharge scenario'' appendix?
254.27 What information must I include in the ''Dispersant use plan'' appendix?
254.28 What information must I include in the ''In situ burning plan'' appendix?
254.29 What information must I include in the ''Training and drills'' appendix?
254.30 When must I revise my OSRP?

Subpart C—Related Requirements for Outer Continental Shelf Facilities

254.40 Records.
254.41 Training your response personnel.
254.42 Exercises for your response personnel and equipment.
254.43 Maintenance and periodic inspection of response equipment.
254.44 Calculating response equipment effective daily recovery capacities.
254.45 Verifying the capabilities of your response equipment.
254.46 Whom do I notify if an oil spill occurs?
254.47 Determining the volume of oil 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.
254.51 Modifying an existing OCS OSRP.
254.52 Following the format for an OCS OSRP.
254.53 Submitting an OSRP developed under State requirements.
254.54 Spill prevention for facilities located in State waters seaward of the coast line.
254.55 Spill response plans for facilities located in Alaska State waters seaward of the coast line in the Chukchi and Beaufort Seas.

Subpart E—Oil-Spill Response Requirements for Facilities Located on the Arctic OCS

254.65 Purpose.
254.66–254.69 [Reserved]
254.70 What are the additional requirements for facilities conducting exploratory drilling from a MODU on the Arctic OCS?
254.71–254.79 [Reserved]
254.80 What additional information must I include in the ''Emergency response action plan'' section for facilities conducting exploratory drilling from a MODU on the Arctic OCS?
254.81–254.89 [Reserved]
254.90 What are the additional requirements for exercises of your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

AUTHORITY: 33 U.S.C. 1321.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Subpart A—General

§ 254.1 Who must submit an oil spill response plan (OSRP)?

(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 an oil spill response plan (OSRP) to BSEE for approval. Your OSRP 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 OSRP for an abandoned facility until you physically remove or dismantle the facility or until the Chief, Oil Spill Preparedness Division (OSPD) 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 Chief, OSPD.

(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 BSEE, you may contact the Chief, OSPD, offer to accept BSEE jurisdiction over your facility, and request that BSEE seek from the agency with jurisdiction over your facility a relinquishment of that jurisdiction.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36151, June 6, 2016]

§ 254.2 When must I submit an OSRP?

(a) You must submit, and BSEE must approve, an OSRP 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 OSRP.

(b) Despite the provisions of paragraph (a) of this section, you may operate your facility after you submit your OSRP while BSEE reviews it for approval. To operate a facility without an approved OSRP, you must certify in writing to the Chief, OSPD 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 Chief, OSPD, 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. BSEE will not allow you to operate a facility for more than 2 years without an approved OSRP.

[81 FR 36151, June 6, 2016]

§ 254.3 May I cover more than one facility in my OSRP?

(a) Your OSRP 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 BSEE Region (see definition of Regional OSRP in § 254.6).

(b) Regional OSRPs must address all the elements required for an OSRP in subpart B, or subpart D of this part, as appropriate.

(c) When developing a Regional OSRP, you may group leases or facilities subject to the approval of the Chief, OSPD, 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 Chief, OSPD, may specify how to address the elements of a Regional OSRP. The Chief, OSPD, also may require that Regional OSRPs contain additional information if necessary for compliance with appropriate laws and regulations.

[81 FR 36151, June 6, 2016]

§ 254.4 May I reference other documents in my OSRP?

You may reference information contained in other readily accessible documents in your OSRP. Examples of documents that you may reference are the National Contingency Plan (NCP), Area Contingency Plan (ACP), BSEE or BOEM environmental documents, and Oil Spill Removal Organization (OSRO) documents that are readily accessible to the Chief, OSPD. You must ensure that the Chief, OSPD, possesses or is

provided with copies of all OSRO documents you reference. You should contact the Chief, OSPD, if you want to know whether a reference is acceptable.

[81 FR 36152, June 6, 2016]

§ 254.5 General response plan requirements.

(a) The OSRP must provide for response to an oil spill from the facility. You must immediately carry out the provisions of the OSRP 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 OSRP, 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 OSRP 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 Chief, OSPD, requires for compliance with appropriate laws and regulations.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

§ 254.6 Definitions.

For the purposes of this part:

Adverse weather conditions means, for the purposes of this part, 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 conditions include, but are not limited to: fog, inhospitable water and air temperatures, wind, sea ice, extreme cold, freezing spray, snow, currents, sea states, and extended periods of low light. Adverse weather conditions do not refer to conditions under which it would be dangerous or impossible to respond to a spill, such as a hurricane.

Arctic OCS means the Beaufort Sea and Chukchi Sea Planning Areas (for more information on these areas, *see* the Proposed Final OCS Oil and Gas Leasing Program for 2012–2017 (June 2012) at *http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Five-Year-Program/2012-2017/Program-Area-Maps/index.aspx*).

Area Contingency Plan means an Area Contingency Plan prepared and published under section 311(j) of the Federal Water Pollution Control Act (FWPCA).

Chief, OSPD means the Chief, BSEE Oil Spill Preparedness Division or designee.

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 Manager means the BSEE officer with authority and responsibility for a district within a BSEE 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.

Ice intervention practices mean the equipment, vessels, and procedures used to increase oil encounter rates and the effectiveness of spill response techniques and equipment when sea ice is present.

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.

OSRP means an Oil Spill Response Plan.

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 BSEE Region.

Regional Supervisor means the BSEE official with responsibility and authority for operations or other designated program functions within a BSEE 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 an OSRP 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016; 81 FR 46563, July 15, 2016]

§ 254.7 How do I submit my OSRP to the BSEE?

You must submit the number of copies of your OSRP that the appropriate BSEE regional office requires. If you prefer to use improved information technology such as electronic filing to submit your plan, ask the Chief, OSPD, for further guidance.

(a) Send OSRPs for facilities located seaward of the coast line of Alaska to: Bureau of Safety and Environmental Enforcement, Oil Spill Preparedness Division, Attention: Senior Analyst, 3801 Centerpoint Drive, Suite #500, Anchorage, AK 99503–5823.

(b) Send OSRPs for facilities in the Gulf of Mexico or Atlantic Ocean to: Bureau of Safety and Environmental Enforcement, Oil Spill Preparedness Division, Attention: GOM Section Supervisor, 1201 Elmwood Park Boulevard, New Orleans, LA 70123–2394.

(c) Send OSRPs for facilities in the Pacific Ocean (except seaward of the coast line of Alaska) to: Bureau of Safety and Environmental Enforcement, Oil Spill Preparedness Division, Attention: Senior Analyst, 760 Paseo Camarillo, Suite 201, Camarillo, CA 93010–6002.

[81 FR 36152, June 6, 2016]

§ 254.8 May I appeal decisions under this part?

See 30 CFR part 290 for instructions on how to appeal any order or decision that we issue under this part.

§ 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 1014–0007. The title of this information collection is ''30 CFR part 254, Oil Spill Response Requirements for Facilities Located Seaward of the Coast line.''

(b) BSEE collects this information to ensure that the owner or operator of an offshore facility is prepared to respond to an oil spill. BSEE 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, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

Subpart B—Oil-Spill Response Plans for Outer Continental Shelf Facilities

§ 254.20 Purpose.

This subpart describes the requirements for preparing OSRPs for facilities located on the OCS.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

§ 254.21 How must I format my OSRP?

(a) You must divide your OSRP for OCS facilities into the sections specified in paragraph (b) of this section and explained in the other sections of this subpart. The OSRP 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 Chief, OSPD that they provide for equal or greater levels of preparedness.

(b) Your OSRP must include:
(1) Introduction and OSRP 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

§ 254.22 What information must I include in the "Introduction and OSRP contents" section?

The ''Introduction and OSRP contents'' section must provide:

(a) Identification of the facility the OSRP covers, including its location and type;

(b) A table of contents;

(c) A record of changes made to the OSRP; and

(d) A cross-reference table, if needed, because you are using an alternate format for your OSRP.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

§ 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 OSRP. 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

§ 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 OSRP. 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36152, June 6, 2016]

§ 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 OSRP?

(a) You must review your OSRP at least every 2 years and submit all resulting modifications to the Chief, OSPD. If this review does not result in modifications, you must inform the Chief, OSPD, in writing that there are no changes.

(b) You must submit revisions to your OSRP 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 OSRP; or

(4) There is a significant change to the Area Contingency Plan(s).

(c) The Chief, OSPD, may require that you resubmit your OSRP if the OSRP has become outdated or if numerous revisions have made its use difficult.

(d) The Chief, OSPD, 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 OSRPs.

(e) The Chief, OSPD, may require you to revise your OSRP 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 Chief, OSPD, obtained.

[81 FR 36152, June 6, 2016]

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 BSEE 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 OSRP for at least 2 years. They

must be made available to any authorized BSEE representative upon request.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 254.42 Exercises for your response personnel and equipment.

(a) You must exercise your entire OSRP at least once every 3 years (triennial exercise). You may satisfy this requirement by conducting separate exercises for individual parts of the OSRP over the 3-year period; you do not have to exercise your entire OSRP 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 OSRP 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 BSEE 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) BSEE 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. BSEE 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 OSRP. Records showing that OSROs 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 Chief, OSPD 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 BSEE 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 Chief, OSPD may require changes in the frequency or location of the required exercises, equipment to be deployed and operated, or deployment procedures or strategies. The Chief, OSPD 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 Chief, OSPD.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 254.43 Maintenance and periodic inspection of response equipment.

(a) You must ensure that the response equipment listed in your OSRP 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 BSEE representative upon request.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 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 OSRP 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).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 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 OSRP 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 BSEE.

(b) You must conduct any required performance testing of booms in accordance with BSEE-approved test criteria. You may use the document ''Test Protocol for the Evaluation of Oil-Spill Containment Booms,'' available from BSEE, for guidance. Performance testing of skimmers also must be conducted in accordance with BSEE approved test criteria. You may use the document ''Suggested Test Protocol for the Evaluation of Oil Spill Skimmers for the OCS,'' available from BSEE, for guidance.

(c) You are responsible for any required testing of equipment performance and for the accuracy of the information submitted.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 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 follow up report for any spill from your facility of 1 barrel or more. The Chief, OSPD 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 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 Chief, OSPD for instructions on the calculation of the volume of your worst case discharge scenario.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

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 BSEE 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 OSRP.

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 OSRP 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 BSEE office if you have any questions on how to prepare this Regional Response Plan.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 254.52 Following the format for an OCS OSRP.

You may develop a response OSRP following the requirements for plans for OCS facilities found in subpart B of this part.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 254.53 Submitting an OSRP developed under State requirements.

(a) You may submit a response plan to BSEE for approval that you developed in accordance with the laws or regulations of the appropriate State. The OSRP 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 254.54 Spill prevention for facilities located in State waters seaward of the coast line.

In addition to your OSRP, you must submit to the Chief, OSPD, 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 Chief, OSPD 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016; 87 FR 39337, July 1, 2022]

§ 254.55 Spill response plans for facilities located in Alaska State waters seaward of the coast line in the Chukchi and Beaufort Seas.

Response plans for facilities conducting exploratory drilling operations from a MODU seaward of the coast line in Alaska State waters in the Chukchi and Beaufort Seas must follow the requirements contained within subpart E

of this part, in addition to the other requirements of this subpart. Such response plans must address how the source control procedures selected to comply with State law will be integrated into the planning, training, and exercise requirements of §§ 254.70(a), 254.90(a), and 254.90(c), in the event that the proposed operations do not incorporate the capping stack, cap and flow system, containment dome, and/or other similar subsea and surface devices and equipment and vessels referenced in those sections.

[81 FR 46563, July 15, 2016]

Subpart E—Oil-Spill Response Requirements for Facilities Located on the Arctic OCS

SOURCE: 81 FR 46564, July 15, 2016, unless otherwise noted.

§ 254.65 Purpose.

This subpart describes the additional requirements for preparing OSRPs and maintaining oil spill preparedness for facilities conducting exploratory drilling operations from a mobile offshore drilling unit (MODU) on the Arctic OCS.

§§ 254.66–254.69 [Reserved]

§ 254.70 What are the additional requirements for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

In addition to meeting the applicable requirements of this part, your OSRP must:

(a) Describe how the relevant personnel, equipment, materials, and support vessels associated with the capping stack, cap and flow system, containment dome, and other similar subsea and surface devices and equipment and vessels will be integrated into oil spill response incident action planning;

(b) Describe how you will address human factors, such as cold stress and cold related conditions, associated with oil spill response activities in adverse weather conditions and their impacts on decision-making and health and safety; and

(c) Undergo plan-holder review prior to handling, storing, or transporting oil in connection with seasonal exploratory drilling activities, and all resulting modifications must be submitted 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. The requirements of this paragraph (c) are in lieu of the requirements in § 254.30(a).

§§ 254.71–254.79 [Reserved]

§ 254.80 What additional information must I include in the "Emergency response action plan" section for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

In addition to the requirements in § 254.23, you must include the following information in the emergency response action plan section of your OSRP:

(a) A description of your ice intervention practices and how they will improve the effectiveness of the oil spill response options and strategies that are listed in your OSRP in the presence of sea ice. When developing the ice intervention practices for your OSRP, you must consider, at a minimum, the use of specialized tactics, modified response equipment, ice management assist vessels, and technologies for the identification, tracking, containment and removal of oil in ice.

(b) On areas of the Arctic OCS where a planned shore-based response would not satisfy § 254.1(a):

(1) A list of all resources required to ensure an effective offshore-based response capable of operating in adverse weather conditions. This list must include a description of how you will ensure the shortest possible transit times, including but not limited to establishing an offshore resource management capability (e.g., sea-based staging, maintenance, and berthing logistics); and

(2) A list and description of logistics resupply chains, including waste management, that effectively factor in the remote and limited infrastructure that exists in the Arctic and ensure you can adequately sustain all oil spill response activities for the duration of the response. The components of the logistics supply chain include, but are not limited to:

(i) Personnel and equipment transport services;

(ii) Airfields and types of aircraft that can be supported;

(iii) Capabilities to mobilize supplies (e.g., response equipment, fuel, food, fresh water) and personnel to the response sites;

(iv) Onshore staging areas, storage areas that may be used en-route to staging areas, and camp facilities to support response personnel conducting offshore, nearshore and shoreline response; and

(v) Management of recovered fluid and contaminated debris and response materials (e.g., oiled sorbents), as well as waste streams generated at offshore and on-shore support facilities (e.g., sewage, food, and medical).

(c) A description of the system you will use to maintain real-time location tracking for all response resources while operating, transiting, or staging/maintaining such resources during a spill response.

§§ 254.81–254.89 [Reserved]

§ 254.90 What are the additional requirements for exercises of your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS?

In addition to the requirements in § 254.42, the following requirements apply to exercises for your response personnel and equipment for facilities conducting exploratory drilling from a MODU on the Arctic OCS:

(a) You must incorporate the personnel, materials, and equipment identified in § 254.70(a), the safe working practices identified in § 254.70(b), the ice intervention practices described in § 254.80(a), the offshore-based response requirements in § 254.80(b), and the resource tracking requirements in § 254.80(c) into your spill-response training and exercise activities.

(b) For each season in which you plan to conduct exploratory drilling operations from a MODU on the Arctic OCS, you must notify the Regional Supervisor 60 days prior to handling, storing, or transporting oil.

(c) After the Regional Supervisor receives notice pursuant to § 254.90(b), the Regional Supervisor may direct you to deploy and operate your spill response equipment and/or your capping stack, cap and flow system, and containment dome, and other similar subsea and surface devices and equipment and vessels, as part of announced or unannounced exercises or compliance inspections. For the purposes of this section, spill response equipment does not include the use of blowout preventers, diverters, heavy weight mud to kill the well, relief wells, or other similar conventional well control options.

PART 256—LEASING OF SULPHUR OR OIL AND GAS IN THE OUTER CONTINENTAL SHELF

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

Sec.
256.1 Purpose.
256.7 Cross references.
256.8–256.12 [Reserved]

Subpart B—Assignments, Transfers, and Extensions

256.70 Extension of lease by drilling or well reworking operations.
256.71 Directional drilling.
256.72 Compensatory payments as production.
256.73 Effect of suspensions on lease term.

Subpart C—Termination of Leases

256.77 Cancellation of leases.

Subpart D—Section 6 Leases

256.79 Effect of regulations on lease.

AUTHORITY: 31 U.S.C. 9701, 42 U.S.C. 6213, 43 U.S.C. 1334, Pub. L. 109–432.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Subpart A—Outer Continental Shelf Oil, Gas, and Sulphur Management, General

§ 256.1 Purpose.

The purpose of the regulations in 30 CFR part 256 is to establish the procedures under which the Secretary of the Interior (Secretary) will exercise the authority to administer a leasing program for oil, gas and sulphur. The procedures under which the Secretary will exercise the authority to administer a

program to grant rights-of-way, are addressed in part 250, subpart J.

§ 256.7 Cross references.

(a) For Bureau of Safety and Environmental Enforcement (BSEE) regulations governing exploration, development and production on leases, see 30 CFR parts 250 and 270.

(b) For BSEE 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.

(j) For Bureau of Ocean Energy Management (BOEM) regulations, see 30 CFR chapter V.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

Subpart B—Assignments, Transfers, and Extensions

SOURCE: 76 FR 64462, Oct. 18, 2011, Redesignated at 81 FR 36153, June 6, 2016.

§ 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 250.180.

§ 256.71 Directional drilling.

In accordance with a BOEM-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, drilling 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.

§ 256.73 Effect of suspensions on lease term.

(a) A suspension may extend the term of a lease (see 30 CFR 250.171) with the extension being the length of time the suspension is in effect except as provided in paragraph (b) of this section.

(b) A Directed Suspension does not extend the lease term when the Regional Supervisor directs a suspension because of:

(1) Gross negligence; or

(2) A willful violation of a provision of the lease or governing regulations.

(c) BSEE may issue suspensions for a period of up to 5 years per suspension. The Regional Supervisor will set the length of the suspension based on the conditions of the individual case involved. BSEE may grant consecutive suspensions. For more information on

suspension of operations or production refer to the section under the heading ''Suspensions'' in 30 CFR part 250, subpart A.

Subpart C—Termination of Leases

SOURCE: 76 FR 64462, Oct. 18, 2011, Redesignated at 81 FR 36153, June 6, 2016.

§ 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 § 550.182 shall apply as appropriate.

Subpart D—Section 6 Leases

SOURCE: 76 FR 64462, Oct. 18, 2011, Redesignated at 81 FR 36153, June 6, 2016.

§ 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.

PARTS 259–260 [RESERVED]

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: 43 U.S.C. 1863.

SOURCE: 76 FR 64462, Oct. 18, 2011, 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 following meanings:

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 part, 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 must proceed in accordance with the provisions of 30 CFR 250, subpart N.

§ 270.7 Remedies.

In addition to the penalties available under 30 CFR part 250, subpart N, 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 ON THE OUTER CONTINENTAL SHELF

Subparts A–B [Reserved]

Subpart C—Obligations Under This Part

INTERRUPTED ACTIVITIES

Sec.
280.20–280.24 [Reserved]
280.25 When may BSEE require me to stop activities under this part?
280.26 When may I resume activities?
280.27 When may BSEE cancel my permit?
280.28 May I relinquish my permit?

Subparts D–E [Reserved]

AUTHORITY: 43 U.S.C. 1334.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Subparts A–B [Reserved]

Subpart C—Obligations Under This Part

INTERRUPTED ACTIVITIES

§§ 280.20–280.24 [Reserved]

§ 280.25 When may BSEE require me to stop activities under this part?

(a) We may temporarily stop prospecting or scientific research activities under a permit when the Regional Director determines that:

(1) Activities pose a threat of serious, irreparable, or immediate harm. This includes damage to life (including fish and other aquatic life), property, and any minerals (in areas leased or not leased), to the marine, coastal, or human environment, or to an archaeological resource;

(2) You failed to comply with any applicable law, regulation, order or provision of the permit. This would include the required submission of reports, well records or logs, and G&G data and information within the time specified; or

(3) Stopping the activities is in the interest of National security or defense.

(b) The Regional Director will advise you either orally or in writing of the procedures to temporarily stop activities. We will confirm an oral notification in writing and deliver all written notifications by courier or certified/registered mail. You must stop all activities under a permit as soon as you receive an oral or written notification.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 280.26 When may I resume activities?

The Regional Director will advise you when you may start your permit activities again.

§ 280.27 When may BSEE cancel my permit?

The Regional Director may cancel a permit at any time.

(a) If we cancel your permit, the Regional Director will advise you by certified or registered mail 30 days before the cancellation date and will state the reason.

(b) After we cancel your permit, you are still responsible for proper abandonment of any drill site according to the requirements of 30 CFR 251.7(b)(8). You must comply with all other obligations specified in this part or in the permit.

§ 280.28 May I relinquish my permit?

(a) You may relinquish your permit at any time by advising the Bureau of Ocean Energy Management Regional Director by certified or registered mail 30 days in advance.

(b) After you relinquish your permit, you are still responsible for proper abandonment of any drill sites according to the requirements of 30 CFR

251.7(b)(8). You must also comply with all other obligations specified in this part or in the permit.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

Subparts D–E [Reserved]

PART 281 [RESERVED]

PART 282—OPERATIONS IN THE OUTER CONTINENTAL SHELF FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR

Subpart A—General

Sec.
282.0 Authority for information collection.
282.1 Purpose and authority.
282.2 Scope.
282.3 Definitions.
282.4 [Reserved]
282.5 Disclosure of data and information to the public.
282.6 Disclosure of data and information to an adjacent State.
282.7 Jurisdictional controversies.

Subpart B—Jurisdiction and Responsibilities of Director

282.10 Jurisdiction and responsibilities of Director.
282.11 Director's authority.
282.12 Director's responsibilities.
282.13 Suspension of production or other operations.
282.14 Noncompliance, remedies, and penalties.
282.15 [Reserved]

Subpart C—Obligations and Responsibilities of Lessees

282.20 [Reserved]
282.21 Plans, general.
282.22–282.26 [Reserved]
282.27 Conduct of operations.
282.28 Environmental protection measures.
282.29–282.30 [Reserved]
282.31 Suspension of production or other operations.

Subpart D—Payments

282.40 [Reserved]
282.41 Method of royalty calculation
282.42 [Reserved]

Subpart E—Appeals

282.50 Appeals.

AUTHORITY: 43 U.S.C. 1334.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Subpart A—General

§282.0 Authority for information collection.

(a) 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 1014–0021. The information is being collected to inform the Bureau of Safety and Environmental Enforcement (BSEE) of general mining operations in the Outer Continental Shelf (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.

(b) Send comments regarding any aspect of the collection of information under this part, including suggestions for reducing the burden, to: Information Collection Clearance Officer, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§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 BSEE.

§ 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 following meaning:

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 BSEE 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 overlying 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 include 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 282.4 [Reserved]

§ 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 ore body, 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 BSEE 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) and (c) 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 30 CFR part 581, or pursuant to a right of use and easement granted under 30 CFR 582.30, by or on behalf of a lessee or the holder of a right of use and easement.

§ 282.11 Director's authority.

(a)–(c) [Reserved]

(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)–(d) [Reserved]

(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) [Reserved]

(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 to the Bureau of Ocean Energy Management for approval in accordance with the requirements for the approval of such plans in part 582 of this title.

(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 will 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. In choosing between alternative mitigation measures, the Director 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. When deemed appropriate by the Director, the lessee must submit to the Bureau of Ocean Energy Management a revised Delineation, Testing, or Mining Plan that incorporates the mitigation measures required by the Director.

(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 30 CFR 581.28(b) 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 30 CFR 581.28(b), 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36153, June 6, 2016]

§ 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 $40,000 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 30 CFR part 250 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)).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 282.15 [Reserved]

Subpart C—Obligations and Responsibilities of Lessees

§ 282.20 [Reserved]

§ 282.21 Plans, general.

(a)–(d) [Reserved]

(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.

§§ 282.22–282.26 [Reserved]

§ 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 BSEE representatives to inspect its facilities. Upon request, you will be reimbursed by BSEE for the actual costs that you incur as a result of providing transportation to BSEE representatives. In addition, you will be reimbursed for the actual costs that you incur for providing food and quarters for a BSEE representative's stay of more than 12 hours. You must submit an invoice for reimbursement within 90 days of the inspection.

(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 likelihood 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 (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 30 CFR part 250, subpart I.

(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 30 CFR 582.29.

(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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 282.28 Environmental protection measures.

(a)–(b) [Reserved]

(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) [Reserved]

(6) When required, the monitoring plan will 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) [Reserved]

§§ 282.29–282.30 [Reserved]

§ 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 [Reserved]

§ 282.41 Method of royalty calculation.

In the event that the provisions of royalty management regulations in part 1206 of chapter XII 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 [Reserved]

Subpart E—Appeals

§ 282.50 Appeals.

See 30 CFR part 290 for instructions on how to appeal any order or decision that we issue under this part.

PART 285 [RESERVED]

SUBCHAPTER C—APPEALS

PART 290—APPEAL PROCEDURES

Subpart A—Bureau of Safety and Environmental Enforcement Appeal Procedures

Sec.
290.1 What is the purpose of this subpart?
290.2 Who may appeal?
290.3 What is the time limit for filing an appeal?
290.4 How do I file an appeal?
290.5 Can I obtain an extension for filing my Notice of Appeal?
290.6 Are informal resolutions permitted?
290.7 Do I have to comply with the decision or order while my appeal is pending?
290.8 How do I exhaust my administrative remedies?

Subpart B [Reserved]

AUTHORITY: 5 U.S.C. 305; 43 U.S.C. 1334.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Subpart A—Bureau of Safety and Environmental Enforcement Appeal Procedures

§ 290.1 What is the purpose of this subpart?

The purpose of this subpart is to explain the procedures for appeals of Bureau of Safety and Environmental Enforcement (BSEE) decisions and orders issued under 30 CFR chapter II.

§ 290.2 Who may appeal?

If you are adversely affected by a BSEE official's final decision or order issued under 30 CFR chapter II, you may appeal that decision or order to the Interior Board of Land Appeals (IBLA). Your appeal must conform with the procedures found in this subpart and 43 CFR part 4, subpart E.

§ 290.3 What is the time limit for filing an appeal?

You must file your appeal within 60 days after you receive BSEE's final decision or order. The 60-day time period applies rather than the time period provided in 43 CFR 4.411(a). A decision or order is received on the date you sign a receipt confirming delivery or, if there is no receipt, the date otherwise documented.

§ 290.4 How do I file an appeal?

For your appeal to be filed, BSEE must receive all of the following within 60 days after you receive the decision or order:

(a) A written Notice of Appeal together with a copy of the decision or order you are appealing in the office of the BSEE officer that issued the decision or order. You cannot extend the 60-day period for that office to receive your Notice of Appeal; and

(b) A nonrefundable processing fee of $150 paid with the Notice of Appeal.

(1) You must pay electronically through the Fees for Services page on the BSEE Web site at *http://www.bsee.gov*, and you must include a copy of the *Pay.gov* confirmation receipt page with your Notice of Appeal.

(2) You cannot extend the 60-day period for payment of the processing fee.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 290.5 Can I obtain an extension for filing my Notice of Appeal?

You cannot obtain an extension of time to file the Notice of Appeal. See 43 CFR 4.411(c).

§ 290.6 Are informal resolutions permitted?

(a) You may seek informal resolution with the issuing officer's next level supervisor during the 60-day period established in § 290.3.

(b) Nothing in this subpart precludes resolution by settlement of any appeal or matter pending in the administrative process after the 60-day period established in § 290.3.

§ 290.7 Do I have to comply with the decision or order while my appeal is pending?

(a) The decision or order is effective during the 60-day period for filing an appeal under § 290.3 unless:

(1) BSEE notifies you that the decision or order, or some portion of it, is suspended during this period because there is no likelihood of immediate and

irreparable harm to human life, the environment, any mineral deposit, or property; or

(2) You post a surety bond under 30 CFR 250.1409 pending the appeal challenging an order to pay a civil penalty.

(b) This section applies rather than 43 CFR 4.21(a) for appeals of BSEE orders.

(c) After you file your appeal, IBLA may grant a stay of a decision or order under 43 CFR 4.21(b); however, a decision or order remains in effect until IBLA grants your request for a stay of the decision or order under appeal.

§ 290.8 How do I exhaust my administrative remedies?

(a) If you receive a decision or order issued under chapter II, subchapter B, you must appeal that decision or order to IBLA under 43 CFR part 4, subpart E to exhaust administrative remedies.

(b) This section does not apply if the Assistant Secretary for Land and Minerals Management or the IBLA makes a decision or order immediately effective notwithstanding an appeal.

Subpart B [Reserved]

PART 291—OPEN AND NONDISCRIMINATORY ACCESS TO OIL AND GAS PIPELINES UNDER THE OUTER CONTINENTAL SHELF LANDS ACT

Sec.

291.1 What is BSEE's authority to collect information?
291.100 What is the purpose of this part?
291.101 What definitions apply to this part?
291.102 May I call the BSEE Hotline to informally resolve an allegation that open and nondiscriminatory access was denied?
291.103 May I use alternative dispute resolution (ADR) to informally resolve an allegation that and nondiscriminatory access was denied?
291.104 Who may file a complaint or a third-party brief?
291.105 What must a complaint contain?
291.106 How do I file a complaint?
291.107 How do I answer a complaint?
291.108 How do I pay the processing fee?
291.109 Can I ask for a fee waiver or a reduced processing fee?
291.110 Who may BSEE require to produce information?
291.111 How does BSEE treat the confidential information I provide?
291.112 What process will BSEE follow in rendering a decision on whether a grantee or transporter has provided open and nondiscriminatory access?
291.113 What actions may BSEE take to remedy denial of open and nondiscriminatory access?
291.114 How do I appeal to the IBLA?
291.115 How do I exhaust administrative remedies?

AUTHORITY: 31 U.S.C. 9701, 43 U.S.C. 1334.

SOURCE: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

§ 291.1 What is BSEE's authority to collect information?

(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.*, and assigned OMB Control Number 1014–0012.

(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) We use the information collected to determine whether or not the shipper has been denied open and nondiscriminatory access to Outer Continental Shelf (OCS) pipelines as sections of 5(e) and (f) of the OCS Lands Act (OCSLA) require.

(d) Respondents are companies that ship or transport oil and gas production across the OCS. Responses are required to obtain or retain benefits. We will protect information considered proprietary under applicable law.

(e) 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, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 291.100 What is the purpose of this part?

This part:

(a) Explains the procedures for filing a complaint with the Director, Bureau of Safety and Environmental Enforcement (BSEE) alleging that a grantee or

transporter has denied a shipper of production from the OCS open and nondiscriminatory access to a pipeline;

(b) Explains the procedures BSEE will employ to determine whether violations of the requirements of the OCSLA have occurred, and to remedy any violations; and

(c) Provides for alternative informal means of resolving pipeline access disputes through either Hotline-assisted procedures or alternative dispute resolution (ADR).

§ 291.101 What definitions apply to this part?

As used in this part:

Accessory means a platform, a major subsea manifold, or similar subsea structure attached to a right-of-way (ROW) pipeline to support pump stations, compressors, manifolds, *etc.* The site used for an accessory is part of the pipeline ROW grant.

Appurtenance means equipment, device, apparatus, or other object attached to a horizontal component or riser. Examples include anodes, valves, flanges, fittings, umbilicals, subsea manifolds, templates, pipeline end modules (PLEMs), pipeline end terminals (PLETs), anode sleds, other sleds, and jumpers (other than jumpers connecting subsea wells to manifolds).

FERC pipeline means any pipeline within the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act, 15 U.S.C. 717–717z, or the Interstate Commerce Act, 42 U.S.C. 7172(a) and (b).

Grantee means any person to whom BSEE has issued an oil or gas pipeline permit, license, easement, right-of-way, or other grant of authority for transportation on or across the OCS under 30 CFR part 250, subpart J, or 43 U.S.C. 1337(p), and any person who has an assignment of a permit, license, easement, right-of-way or other grant of authority, or who has an assignment of any rights subject to any of those grants of authority under 30 CFR part 250, subpart J or 43 U.S.C. 1337(p).

IBLA means the Interior Board of Land Appeals.

OCSLA pipeline means any oil or gas pipeline for which BSEE has issued a permit, license, easement, right-of-way, or other grant of authority.

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.

Party means any person who files a complaint, any person who files an answer, and BSEE.

Person means an individual, corporation, government entity, partnership, association (including a trust or limited liability company), consortium, or joint venture (when established as a separate entity).

Pipeline is the piping, risers, accessories and appurtenances installed for transportation of oil and gas.

Serve means personally delivering a document to a person, or sending a document by U.S. mail or private delivery services that provide proof of delivery (such as return receipt requested) to a person.

Shipper means a person who contracts or wants to contract with a grantee or transporter to transport oil or gas through the grantee's or transporter's pipeline.

Transportation means, for purposes of this part only, the movement of oil or gas through an OCSLA pipeline.

Transporter means, for purposes of this part only, any person who owns or operates an OCSLA oil or gas pipeline.

§ 291.102 May I call the BSEE Hotline to informally resolve an allegation that open and nondiscriminatory access was denied?

Before filing a complaint under § 291.106, you may attempt to informally resolve an allegation concerning open and nondiscriminatory access by calling the toll-free BSEE Pipeline Open Access Hotline at 1–888–232–1713.

(a) BSEE Hotline staff will informally seek information needed to resolve the dispute. BSEE Hotline staff will attempt to resolve disputes without litigation or other formal proceedings. The Hotline staff will not attempt to resolve matters that are before BSEE or FERC in docketed proceedings.

(b) BSEE Hotline staff may provide information to you and give informal oral advice. The advice given is not binding on BSEE, the Department of the Interior (DOI), or any other person.

(c) To the extent permitted by law, the BSEE Hotline staff will treat all information it obtains as non-public and confidential.

(d) You may call the BSEE Hotline anonymously.

(e) If you contact the BSEE Hotline, you may file a complaint under this part if discussions assisted by BSEE Hotline staff are unsuccessful at resolving the matter.

(f) You may terminate use of the BSEE Hotline procedure at any time.

§ 291.103 May I use alternative dispute resolution (ADR) to informally resolve an allegation that open and nondiscriminatory access was denied?

You may ask to use ADR either before or after you file a complaint. To make a request, call the BSEE at 1–888–232–1713 or write to us at the following address: Director, Bureau of Safety and Environmental Enforcement, Attention: Office of Policy and Analysis, 1849 C Street, NW., Mail Stop 5438, Washington, DC 20240–0001.

(a) You may request that ADR be administered by:

(1) A contracted ADR provider agreed to by all parties;

(2) The Department's Office of Collaborative Action and Dispute Resolution (CADR); or

(3) BSEE staff trained in ADR and certified by the CADR.

(b) Each party must pay its respective share of all costs and fees associated with any contracted or Departmental ADR provider. For purposes of this section, BSEE is not a party in an ADR proceeding.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 291.104 Who may file a complaint or a third-party brief?

(a) You may file a complaint under this subpart if you are a shipper and you believe that you have been denied open and nondiscriminatory access to an OCSLA pipeline that is not a FERC pipeline.

(b) Any person that believes its interests may be affected by precedents established by adjudication of complaints under this rule may submit a brief to BSEE. The brief must be served following the procedure set out in § 291.107. After considering the brief, it is within BSEE's discretion as to whether BSEE may:

(1) Address the brief in its decision;

(2) Not address the brief in its decision; or

(3) Include the submitter of the brief in the proceeding as a party.

§ 291.105 What must a complaint contain?

For purposes of this subpart, a complaint means a comprehensive written brief stating the legal and factual basis for the allegation that a shipper was denied open and nondiscriminatory access, together with supporting material. A complaint must:

(a) Clearly identify the action or inaction which is alleged to violate 43 U.S.C. 1334(e) or (f)(1)(A);

(b) Explain how the action or inaction violates 43 U.S.C. 1334(e) or (f)(1)(A);

(c) Explain how the action or inaction affects your interests, including practical, operational, or other non-financial impacts;

(d) Estimate any financial impact or burden;

(e) State the specific relief or remedy requested; and

(f) Include all documents that support the facts in your complaint including, but not limited to, contracts and any affidavits that may be necessary to support particular factual allegations.

§ 291.106 How do I file a complaint?

To file a complaint under this part, you must:

(a) File your complaint with the Director, Bureau of Safety and Environmental Enforcement at the following address: Director, Bureau of Safety and Environmental Enforcement, Attention: Office of Policy and Analysis, 1849 C Street, NW., Mail Stop 5438, Washington, DC 20240–0001; and

(b) Include a nonrefundable processing fee of $7,500 under § 291.108(a) or

a request for reduction or waiver of the fee under § 291.109(a); and

(c) Serve your complaint on all persons named in the complaint. If you make a claim under § 291.111 for confidentiality, serve the redacted copy and proposed form of a protective agreement on all persons named in the complaint.

(d) Complaints shall not be filed later than 2 years from the time of the alleged access denial. If the complaint is filed later than 2 years from the time of the alleged access denial, the BSEE Director will not consider the complaint and the case will be closed.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 291.107 How do I answer a complaint?

(a) If you have been served a complaint under § 291.106, you must file an answer within 60 days of receiving the complaint. If you miss this deadline, BSEE may disregard your answer. We consider your answer to be filed when the BSEE Director receives it at the following address: Director, Bureau of Safety and Environmental Enforcement, Attention: Office of Policy and Analysis, 1849 C Street, NW., Mail Stop 5438, Washington, DC 20240–0001.

(b) For purposes of this paragraph, an answer means a comprehensive written brief stating the legal and factual basis refuting the allegations in the complaint, together with supporting material. You must:

(1) Attach to your answer a copy of the complaint or reference the assigned BSEE docket number (you may obtain the docket number by calling the Office of Policy and Analysis at (202) 208–1901);

(2) Explain in your answer why the action or inaction alleged in the complaint does not violate 43 U.S.C. 1334(e) or (f)(1)(A);

(3) Include with your answer all documents in your possession or that you can otherwise obtain that support the facts in your answer including, but not limited to, contracts and any affidavits that may be necessary to support particular factual allegations; and

(4) Provide a copy of your answer to all parties named in the complaint including the complainant. If you make a claim under § 291.111 for confidentiality, serve the redacted copy and proposed form of a protective agreement to all parties named in the complaint, including the complainant.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 291.108 How do I pay the processing fee?

(a) You must pay the processing fee electronically through the Fees for Services page on the BSEE Web site at *http://www.bsee.gov*, and you must include a copy of the *Pay.gov* confirmation receipt page with your complaint.

(b) You must include with the payment:

(1) Your taxpayer identification number;

(2) Your payor identification number, if applicable; and

(3) The complaint caption, or any other applicable identification of the complaint you are filing.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§ 291.109 Can I ask for a fee waiver or a reduced processing fee?

(a) BSEE may grant a fee waiver or fee reduction in extraordinary circumstances. You may request a waiver or reduction of your fee by:

(1) Sending a written request to the BSEE Office of Policy and Analysis when you file your complaint; and

(2) Demonstrating in your request that you are unable to pay the fee or that payment of the full fee would impose an undue hardship upon you.

(b) The BSEE Office of Policy and Analysis will send you a written decision granting or denying your request for a fee waiver or a fee reduction.

(1) If we grant your request for a fee reduction, you must pay the reduced processing fee within 30 days of the date you receive our decision.

(2) If we deny your request, you must pay the entire processing fee within 30 days of the date you receive the decision.

(3) BSEE's decision granting or denying a fee waiver or reduction is final for the Department.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36154, June 6, 2016]

§291.110 Who may BSEE require to produce information?

(a) BSEE may require any lessee, operator of a lease or unit, shipper, grantee, or transporter to provide information that BSEE believes is necessary to make a decision on whether open access or nondiscriminatory access was denied.

(b) If you are a party and fail to provide information BSEE requires under paragraph (a) of this section, BSEE may:

(1) Assess civil penalties under 30 CFR part 250, subpart N;

(2) Dismiss your complaint or consider your answer incomplete; or

(3) Presume the required information is adverse to you on the factual issues to which the information is relevant.

(c) If you are not a party to a complaint and fail to provide information BSEE requires under paragraph (a) of this section, BSEE may assess civil penalties under 30 CFR part 250, subpart N.

§291.111 How does BSEE treat the confidential information I provide?

(a) Any person who provides documents under this part in response to a request by BSEE to inform a decision on whether open access or nondiscriminatory access was denied may claim that some or all of the information contained in a particular document is confidential. If you claim confidential treatment, then when you provide the document to BSEE you must:

(1) Provide a complete unredacted copy of the document and indicate on that copy that you are making a request for confidential treatment for some or all of the information in the document.

(2) Provide a statement specifying the specific statutory justification for nondisclosure of the information for which you claim confidential treatment. General claims of confidentiality are not sufficient. You must furnish sufficient information for BSEE to make an informed decision on the request for confidential treatment.

(3) Provide a second copy of the document from which you have redacted the information for which you wish to claim confidential treatment. If you do not submit a second copy of the document with the confidential information redacted, BSEE may assume that there is no objection to public disclosure of the document in its entirety.

(b) In making data and information you submit available to the public, BSEE will not disclose documents exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552) and will follow the procedures set forth in the implementing regulations at 43 CFR part 2 to give submitters an opportunity to object to disclosure.

(c) BSEE retains the right to make the determination with regard to any claim of confidentiality. BSEE will notify you of its decision to deny a claim, in whole or in part, and, to the extent permitted by law, will give you an opportunity to respond at least 10 days before its public disclosure.

§291.112 What process will BSEE follow in rendering a decision on whether a grantee or transporter has provided open and nondiscriminatory access?

BSEE will begin processing a complaint upon receipt of a processing fee or granting a waiver of the fee. The BSEE Director will review the complaint, answer, and other information, and will serve all parties with a written decision that:

(a) Makes findings of fact and conclusions of law; and

(b) Renders a decision determining whether the complainant has been denied open and nondiscriminatory access.

§291.113 What actions may BSEE take to remedy denial of open and nondiscriminatory access?

If the BSEE Director's decision under §291.112 determines that the grantee or transporter has not provided open access or nondiscriminatory access, then the decision will describe the actions BSEE will take to require the grantee or transporter to remedy the denial of open access or nondiscriminatory access. The remedies BSEE would require must be consistent with BSEE's statutory authority, regulations, and any limits thereon due to Congressional delegations to other agencies. Actions BSEE may take include, but are not limited to:

(a) Ordering grantees and transporters to provide open and nondiscriminatory access to the complainant;

(b) Assessing civil penalties of up to $10,000 per day under 30 CFR part 250, subpart N, for failure to comply with a BSEE order to provide open access or nondiscriminatory access. Penalties will begin to accrue 60 days after the grantee or transporter receives the order to provide open and nondiscriminatory access if it has not provided such access by that time. However, if BSEE determines that requiring the construction of facilities would be an appropriate remedy under the OCSLA, penalties will begin to accrue 10 days after conclusion of diligent construction of needed facilities or 60 days after the grantee or transporter receives the order to provide open and nondiscriminatory access, whichever is later, if it has not provided such access by that time;

(c) Requesting the Attorney General to institute a civil action in the appropriate United States District Court under 43 U.S.C. 1350(a) for a temporary restraining order, injunction, or other appropriate remedy to enforce the open and nondiscriminatory access requirements of 43 U.S.C. 1334(e) and (f)(1)(A); or

(d) Initiating a proceeding to forfeit the right-of-way grant under 43 U.S.C. 1334(e).

§ 291.114 How do I appeal to the IBLA?

Any party, except as provided in § 291.115(b), adversely affected by a decision of the BSEE Director under this part may appeal to the Interior Board of Land Appeals (IBLA) under the procedures in 43 CFR part 4, subpart E.

§ 291.115 How do I exhaust administrative remedies?

(a) If the BSEE Director issues a decision under this part but does not expressly make the decision effective upon issuance, you must appeal the decision to the IBLA under 43 CFR part 4 to exhaust administrative remedies. Such decision will not be effective during the time in which a person adversely affected by the BSEE Director's decision may file a notice of appeal with the IBLA, and the timely filing of a notice of appeal will suspend the effect of the decision pending the decision on appeal.

(b) This section does not apply if a decision was made effective by:

(1) The BSEE Director; or

(2) The Assistant Secretary for Land and Minerals Management.

PARTS 292–299 [RESERVED]

CHAPTER IV—GEOLOGICAL SURVEY, DEPARTMENT OF THE INTERIOR

Part		*Page*
400	[Reserved]	
401	State Water Research Institute Program	327
402	Water-Resources Research Program and the Water-Resources Technology Development Program	332
403–499	[Reserved]	

PART 400 [RESERVED]

PART 401—STATE WATER RESEARCH INSTITUTE PROGRAM

Subpart A—General

Sec.
401.1 Purpose.
401.2 Delegation of authority.
401.3 Definitions.
401.4 Information collection.
401.5 [Reserved]

Subpart B—Designation of Institutes; Institute Programs

401.6 Designation of institutes.
401.7 Programs of institutes.
401.8–401.10 [Reserved]

Subpart C—Application and Management Procedures

401.11 Applications for grants.
401.12 Program management.
401.13–401.18 [Reserved]

Subpart D—Reporting

401.19 Reporting procedures.
401.20–401.25 [Reserved]

Subpart E—Evaluation

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

Sec.
402.1 Purpose.
402.2 Delegation of authority.
402.3 Definitions.
402.4 Information collection.
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.

AUTHORITY: Secs. 105 and 106, Pub. L. 98–242, 98 Stat. 97 (42 U.S.C. 10304 and 10305).

SOURCE: 51 FR 20963, June 10, 1986, unless otherwise noted.

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.

PARTS 403–499 [RESERVED]

CHAPTER V—BUREAU OF OCEAN ENERGY MANAGEMENT, DEPARTMENT OF THE INTERIOR

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

Part		*Page*
500–519	[Reserved]	

SUBCHAPTER B—OFFSHORE

550	Oil and gas and sulphur operations in the Outer Continental Shelf	340
551	Geological and geophysical (G&G) explorations of the Outer Continental Shelf	405
552	Outer Continental Shelf (OCS) Oil and Gas Information Program	419
553	Oil spill financial responsibility for offshore facilities	425
556	Leasing of sulphur or oil and gas and bonding requirements in the Outer Continental Shelf	440
560	Outer Continental Shelf oil and gas leasing	478
570	Nondiscrimination in the Outer Continental Shelf	486
580	Prospecting for minerals other than oil, gas, and sulphur on the Outer Continental Shelf	488
581	Leasing of minerals other than oil, gas, and sulphur in the Outer Continental Shelf	500
582	Operations in the Outer Continental Shelf for minerals other than oil, gas and sulphur	512
583	Negotiated noncompetitive agreements for the use of Outer Continental Shelf sand, gravel, and/or shell resources	530
585	Renewable energy and alternate uses of existing facilities on the Outer Continental Shelf	536

SUBCHAPTER C—APPEALS

590	Appeal procedures	621
591–599	[Reserved]	

SUBCHAPTER A—MINERALS REVENUE MANAGEMENT

PARTS 500–519 [RESERVED]

SUBCHAPTER B—OFFSHORE

PART 550—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

Subpart A—General

AUTHORITY AND DEFINITION OF TERMS

Sec.
550.101 Authority and applicability.
550.102 What does this part do?
550.103 Where can I find more information about the requirements in this part?
550.104 How may I appeal a decision made under BOEM regulations?
550.105 Definitions.

PERFORMANCE STANDARDS

550.115 How do I determine well producibility?
550.116 How do I determine producibility if my well is in the Gulf of Mexico?
550.117 How does a determination of well producibility affect royalty status?
550.118 [Reserved]
550.119 Will BOEM approve subsurface gas storage?
550.120 What standards will BOEM use to regulate leases, rights-of-use and easement, and rights-of-way?
550.121 What must I do to protect health, safety, property, and the environment?
550.122 What effect does subsurface storage have on the lease term?
550.123 Will BOEM allow gas storage on unleased lands?

FEES

550.125 Service fees.
550.126 Electronic payment instructions.

INSPECTION OF OPERATIONS

550.130 [Reserved]

DISQUALIFICATION

550.135 What will BOEM do if my operating performance is unacceptable?
550.136 How will BOEM determine if my operating performance is unacceptable?

SPECIAL TYPES OF APPROVALS

550.140 When will I receive an oral approval?
550.141 May I ever use alternate procedures or equipment?
550.142 How do I receive approval for departures?
550.143 How do I designate an operator?
550.144 How do I designate a new operator when a designation of operator terminates?
550.146 How do I designate an agent or a local agent?
550.147 Who is responsible for fulfilling leasehold obligations?

RIGHT-OF-USE AND EASEMENT

550.160 When will BOEM grant me a right-of-use and easement, and what requirements must I meet?
550.161 What else must I submit with my application?
550.162 May I continue my right-of-use and easement after the termination of any lease on which it is situated?
550.163 If I have a State lease, will BOEM grant me a right-of-use and easement?
550.164 If I have a State lease, what conditions apply for a right-of-use and easement?
550.165 If I have a State lease, what fees do I have to pay for a right-of-use and easement?
550.166 If I have a State lease, what surety bond must I have for a right-of-use and easement?

PRIMARY LEASE REQUIREMENTS, LEASE TERM EXTENSIONS, AND LEASE CANCELLATIONS

550.181 When may the Secretary cancel my lease and when am I compensated for cancellation?
550.182 When may the Secretary cancel a lease at the exploration stage?
550.183 When may BOEM or the Secretary extend or cancel a lease at the development and production stage?
550.184 What is the amount of compensation for lease cancellation?
550.185 When is there no compensation for a lease cancellation?

INFORMATION AND REPORTING REQUIREMENTS

550.186 What reporting information and report forms must I submit?
550.187–550.193 [Reserved]
550.194 How must I protect archaeological resources?
550.195 [Reserved]
550.196 Reimbursements for reproduction and processing costs.
550.197 Data and information to be made available to the public or for limited inspection.

REFERENCES

550.198 [Reserved]
550.199 Paperwork Reduction Act statements—information collection.

Subpart B—Plans and Information

GENERAL INFORMATION

550.200 Definitions.

550.201 What plans and information must I submit before I conduct any activities on my lease or unit?
550.202 What criteria must the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) meet?
550.203 Where can wells be located under an EP, DPP, or DOCD?
550.204 When must I submit my IOP for proposed Arctic exploratory drilling operations and what must the IOP include?
550.205 [Reserved]
550.206 How do I submit the IOP, EP, DPP, or DOCD?

ANCILLARY ACTIVITIES

550.207 What ancillary activities may I conduct?
550.208 If I conduct ancillary activities, what notices must I provide?
550.209 What is the BOEM review process for the notice?
550.210 If I conduct ancillary activities, what reporting and data/information retention requirements must I satisfy?

CONTENTS OF EXPLORATION PLANS (EP)

550.211 What must the EP include?
550.212 What information must accompany the EP?
550.213 What general information must accompany the EP?
550.214 What geological and geophysical (G&G) information must accompany the EP?
550.215 What hydrogen sulfide (H_2S) information must accompany the EP?
550.216 What biological, physical, and socioeconomic information must accompany the EP?
550.217 What solid and liquid wastes and discharges information and cooling water intake information must accompany the EP?
550.218 What air emissions information must accompany the EP?
550.219 What oil and hazardous substance spills information must accompany the EP?
550.220 If I propose activities in the Alaska OCS Region, what planning information must accompany the EP?
550.221 What environmental monitoring information must accompany the EP?
550.222 What lease stipulations information must accompany the EP?
550.223 What mitigation measures information must accompany the EP?
550.224 What information on support vessels, offshore vehicles, and aircraft you will use must accompany the EP?
550.225 What information on the onshore support facilities you will use must accompany the EP?
550.226 What Coastal Zone Management Act (CZMA) information must accompany the EP?
550.227 What environmental impact analysis (EIA) information must accompany the EP?
550.228 What administrative information must accompany the EP?

REVIEW AND DECISION PROCESS FOR THE EP

550.231 After receiving the EP, what will BOEM do?
550.232 What actions will BOEM take after the EP is deemed submitted?
550.233 What decisions will BOEM make on the EP and within what timeframe?
550.234 How do I submit a modified EP or resubmit a disapproved EP, and when will BOEM make a decision?
550.235 If a State objects to the EP's coastal zone consistency certification, what can I do?

CONTENT OF DEVELOPMENT AND PRODUCTION PLANS (DPP) AND DEVELOPMENT OPERATIONS COORDINATION DOCUMENTS (DOCD)

550.241 What must the DPP or DOCD include?
550.242 What information must accompany the DPP or DOCD?
550.243 What general information must accompany the DPP or DOCD?
550.244 What geological and geophysical (G&G) information must accompany the DPP or DOCD?
550.245 What hydrogen sulfide (H_2S) information must accompany the DPP or DOCD?
550.246 What mineral resource conservation information must accompany the DPP or DOCD?
550.247 What biological, physical, and socioeconomic information must accompany the DPP or DOCD?
550.248 What solid and liquid wastes and discharges information and cooling water intake information must accompany the DPP or DOCD?
550.249 What air emissions information must accompany the DPP or DOCD?
550.250 What oil and hazardous substance spills information must accompany the DPP or DOCD?
550.251 If I propose activities in the Alaska OCS Region, what planning information must accompany the DPP?
550.252 What environmental monitoring information must accompany the DPP or DOCD?
550.253 What lease stipulations information must accompany the DPP or DOCD?
550.254 What mitigation measures information must accompany the DPP or DOCD?
550.255 What decommissioning information must accompany the DPP or DOCD?

550.256 What related facilities and operations information must accompany the DPP or DOCD?
550.257 What information on the support vessels, offshore vehicles, and aircraft you will use must accompany the DPP or DOCD?
550.258 What information on the onshore support facilities you will use must accompany the DPP or DOCD?
550.259 What sulphur operations information must accompany the DPP or DOCD?
550.260 What Coastal Zone Management Act (CZMA) information must accompany the DPP or DOCD?
550.261 What environmental impact analysis (EIA) information must accompany the DPP or DOCD?
550.262 What administrative information must accompany the DPP or DOCD?

REVIEW AND DECISION PROCESS FOR THE DPP OR DOCD

550.266 After receiving the DPP or DOCD, what will BOEM do?
550.267 What actions will BOEM take after the DPP or DOCD is deemed submitted?
550.268 How does BOEM respond to recommendations?
550.269 How will BOEM evaluate the environmental impacts of the DPP or DOCD?
550.270 What decisions will BOEM make on the DPP or DOCD and within what timeframe?
550.271 For what reasons will BOEM disapprove the DPP or DOCD?
550.272 If a State objects to the DPP's or DOCD's coastal zone consistency certification, what can I do?
550.273 How do I submit a modified DPP or DOCD or resubmit a disapproved DPP or DOCD?

POST-APPROVAL REQUIREMENTS FOR THE EP, DPP, AND DOCD

550.280 How must I conduct activities under the approved EP, DPP, or DOCD?
550.281 What must I do to conduct activities under the approved EP, DPP, or DOCD?
550.282 Do I have to conduct post-approval monitoring?
550.283 When must I revise or supplement the approved EP, DPP, or DOCD?
550.284 How will BOEM require revisions to the approved EP, DPP, or DOCD?
550.285 How do I submit revised and supplemental EPs, DPPs, and DOCDs?

CONSERVATION INFORMATION DOCUMENTS (CID)

550.296 When and how must I submit a CID or a revision to a CID?
550.297 What information must a CID contain?
550.298 How long will BOEM take to evaluate and make a decision on the CID?
550.299 What operations require approval of the CID?

Subpart C—Pollution Prevention and Control

550.300–550.301 [Reserved]
550.302 Definitions concerning air quality.
550.303 Facilities described in a new or revised Exploration Plan, Development and Production Plan, or Development Operations Coordination Document.
550.304 Existing facilities.

Subpart D—Leasing Maps and Diagrams

550.400 Leasing maps and diagrams.

Subparts E–I [Reserved]

Subpart J—Pipelines and Pipeline Rights of Way

550.1011 Bond requirements for pipeline right-of-way holders.

Subpart K—Oil and Gas Production Requirements

WELL TESTS AND SURVEYS

550.1153 When must I conduct a static bottomhole pressure survey?

CLASSIFYING RESERVOIRS

550.1154 How do I determine if my reservoir is sensitive?
550.1155 What information must I submit for sensitive reservoirs?

OTHER REQUIREMENTS

550.1165 What must I do for enhanced recovery operations?
550.1166 What additional reporting is required for developments in the Alaska OCS Region?
550.1167 What information must I submit with forms and for approvals?

Subparts L–M [Reserved]

Subpart N—Outer Continental Shelf Civil Penalties

OUTER CONTINENTAL SHELF LANDS ACT CIVIL PENALTIES

550.1400 How does BOEM begin the civil penalty process?
550.1401 Index table.
550.1402 Definitions.
550.1403 What is the maximum civil penalty?
550.1404 Which violations will BOEM review for potential civil penalties?
550.1405 When is a case file developed?
550.1406 When will BOEM notify me and provide penalty information?

550.1407 How do I respond to the letter of notification?
550.1408 When will I be notified of the Reviewing Officer's decision?
550.1409 What are my appeal rights?

FEDERAL OIL AND GAS ROYALTY MANAGEMENT ACT CIVIL PENALTIES DEFINITIONS

550.1450 What definitions apply to this subpart?

PENALTIES AFTER A PERIOD TO CORRECT

550.1451 What may BOEM do if I violate a statute, regulation, order, or lease term relating to a Federal oil and gas lease?
550.1452 What if I correct the violation?
550.1453 What if I do not correct the violation?
550.1454 How may I request a hearing on the record on a Notice of Noncompliance?
550.1455 Does my request for a hearing on the record affect the penalties?
550.1456 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

PENALTIES WITHOUT A PERIOD TO CORRECT

550.1460 May I be subject to penalties without prior notice and an opportunity to correct?
550.1461 How will BOEM inform me of violations without a period to correct?
550.1462 How may I request a hearing on the record on a Notice of Noncompliance regarding violations without a period to correct?
550.1463 Does my request for a hearing on the record affect the penalties?
550.1464 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

GENERAL PROVISIONS

550.1470 How does BOEM decide what the amount of the penalty should be?
550.1471 Does the penalty affect whether I owe interest?
550.1472 How will the Office of Hearings and Appeals conduct the hearing on the record?
550.1473 How may I appeal the Administrative Law Judge's decision?
550.1474 May I seek judicial review of the decision of the Interior Board of Land Appeals?
550.1475 When must I pay the penalty?
550.1476 Can BOEM reduce my penalty once it is assessed?
550.1477 How may BOEM collect the penalty?

CRIMINAL PENALTIES

550.1480 May the United States criminally prosecute me for violations under Federal oil and gas leases?

BONDING REQUIREMENTS

550.1490 What standards must my BOEM-specified surety instrument meet?
550.1491 How will BOEM determine the amount of my bond or other surety instrument?

FINANCIAL SOLVENCY REQUIREMENTS

550.1495 How do I demonstrate financial solvency?
550.1496 How will BOEM determine if I am financially solvent?
550.1497 When will BOEM monitor my financial solvency?

Subparts O–S [Reserved]

AUTHORITY: 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General

AUTHORITY AND DEFINITION OF TERMS

§ 550.101 Authority and applicability.

The Secretary of the Interior (Secretary) authorized the Bureau of Ocean Energy Management (BOEM) to regulate oil, gas, and sulphur exploration, development, and production operations on the Outer Continental Shelf (OCS). Under the Secretary's authority, the Director requires that all operations:

(a) Be conducted according to the OCS Lands Act (OCSLA), the regulations in this part, BOEM orders, the lease or right-of-way, and other applicable laws, regulations, and amendments; and

(b) Conform to sound conservation practice to preserve, protect, and develop mineral resources of the OCS to:

(1) Make resources available to 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 receives 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.

§ 550.102 What does this part do?

(a) 30 CFR part 550 contains the regulations of the BOEM Offshore program that govern oil, gas, and sulphur exploration, development, and production operations on the OCS. When you conduct operations on the OCS, you must submit requests, applications, and notices, or provide supplemental information for BOEM approval.

(b) The following table of general references shows where to look for information about these processes.

TABLE—WHERE TO FIND INFORMATION FOR CONDUCTING OPERATIONS

For information about	Refer to
(1) Applications for permit to drill	30 CFR 250, subpart D.
(2) Development and Production Plans (DPP)	30 CFR 550, subpart B.
(3) Downhole commingling	30 CFR 250, subpart K.
(4) Exploration Plans (EP)	30 CFR 550, subpart B.
(5) Flaring	30 CFR 250, subpart K.
(6) Gas measurement	30 CFR 250, subpart L.
(7) Off-lease geological and geophysical permits	30 CFR 551.
(8) Oil spill financial responsibility coverage	30 CFR 553.
(9) Oil and gas production safety systems	30 CFR 250, subpart H.
(10) Oil spill response plans	30 CFR 254.
(11) Oil and gas well-completion operations	30 CFR 250, subpart E.
(12) Oil and gas well-workover operations	30 CFR 250, subpart F.
(13) Decommissioning Activities	30 CFR 250, subpart Q.
(14) Platforms and structures	30 CFR 250, subpart I.
(15) Pipelines and Pipeline Rights-of-Way	30 CFR 250, subpart J and 30 CFR 550, subpart J.
(16) Sulphur operations	30 CFR 250, subpart P.
(17) Training	30 CFR 250, subpart O.
(18) Unitization	30 CFR 250, subpart M.

§ 550.103 Where can I find more information about the requirements in this part?

BOEM may issue Notices to Lessees and Operators (NTLs) that clarify, supplement, or provide more detail about certain requirements. NTLs may also outline what you must provide as required information in your various submissions to BOEM.

§ 550.104 How may I appeal a decision made under BOEM regulations?

To appeal orders or decisions issued under BOEM regulations in 30 CFR parts 550 to 582, follow the procedures in 30 CFR part 590.

§ 550.105 Definitions.

Terms used in this part will have the meanings given in the Act and as defined in this section:

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 under the provisions of the Act, any State:

(1) The laws of which are declared, under 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 according to the proposed activity, will receive oil for processing, refining, or transshipment that 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 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.

Analyzed geological information means data collected under a permit or a lease that have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analysis, laboratory analyses of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

Ancillary activities mean those activities on your lease or unit that you:

(1) Conduct to obtain data and information to ensure proper exploration or development of your lease or unit; and

(2) Can conduct without BOEM approval of an application or permit.

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.

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.

Arctic OCS means the Beaufort Sea and Chukchi Sea Planning Areas (for more information on these areas, *see* the Proposed Final OCS Oil and Gas Leasing Program for 2012–2017 (June 2012) at *http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Five-Year-Program/2012–2017/Program-Area-Maps/index.aspx*).

Arctic OCS conditions means, for the purposes of this part, the conditions operators can reasonably expect during operations on the Arctic OCS. Such conditions, depending on the time of year, include, but are not limited to: extreme cold, freezing spray, snow, extended periods of low light, strong winds, dense fog, sea ice, strong currents, and dangerous sea states. Remote location, relative lack of infrastructure, and the existence of subsistence hunting and fishing areas are also characteristic of the Arctic region.

Attainment area means, for any criteria 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 the Environmental Protection Agency (EPA) to be reliable) not to exceed any primary or secondary ambient air quality standards established by EPA.

Best available and safest technology (BAST) means the best available and safest technologies that the Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.

Best available control technology (BACT) means an emission limitation based on the maximum degree of reduction for each criteria air pollutant and VOC subject to regulation, taking into account energy, environmental and economic impacts, and other costs. The Regional Director will verify the BACT on a case-by-case basis, and it may include reductions achieved through the application of processes, systems, and techniques for the control of each criteria air pollutant and VOC.

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors that 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, under 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 producible or producing well completions on each of two or more leases or portions of leases, with different lease operating interests, from which the lessees plan future production.

Correlative rights when used with respect to lessees of adjacent leases, 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.

Criteria air pollutant means any air pollutant for which the EPA has established a primary or secondary national ambient air quality standard pursuant to section 109 of the Clean Air Act.

Data means facts and statistics, measurements, or samples that have not been analyzed, processed, or interpreted.

Departures mean approvals granted by the appropriate BSEE or BOEM representative for operating requirements/procedures other than those specified in the regulations found in this part. These requirements/procedures may be necessary to control a well; properly develop a lease; conserve natural resources, or protect life, property, or the marine, coastal, or human environment.

Development means those activities that take place following discovery of minerals in paying quantities, including but not limited to geophysical activity, drilling, platform construction, and operation of all directly related onshore support facilities, and which are for the purpose of producing the minerals discovered.

Development geological and geophysical (G&G) activities means those G&G and related data-gathering activities on your lease or unit that you conduct following discovery of oil, gas, or sulphur in paying quantities to detect or imply the presence of oil, gas, or sulphur in commercial quantities.

Director means the Director of BOEM of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

District Manager means the BSEE officer with authority and responsibility for operations or other designated program functions for a district within a BSEE Region.

Easement means an authorization for a nonpossessory, nonexclusive interest in a portion of the OCS, whether leased or unleased, which specifies the rights of the holder to use the area embraced in the easement in a manner consistent with the terms and conditions of the granting authority.

Eastern Gulf of Mexico means all OCS areas of the Gulf of Mexico the BOEM Director decides are adjacent to the State of Florida. The Eastern Gulf of Mexico is not the same as the Eastern Planning Area, an area established for OCS lease sales.

Emission offsets mean emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD).

Enhanced recovery operations mean pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations that alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

Existing facility, as used in § 550.303, means an Outer Continental Shelf (OCS) facility described in an Exploration Plan, a Development and Production Plan, or a Development Operations Coordination Document, approved before June 2, 1980.

Exploration means the commercial search for oil, gas, or sulphur. Activities classified as exploration include but are not limited to:

(1) Geophysical and geological (G&G) surveys using magnetic, gravity, seismic reflection, seismic refraction, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur; and

(2) Any drilling conducted for the purpose of searching for commercial quantities of oil, gas, and sulphur, including the drilling of any additional well needed to delineate any reservoir

to enable the lessee to decide whether to proceed with development and production.

Facility, as used in § 550.303, means all installations or devices permanently or temporarily attached to the seabed. They include mobile offshore drilling units (MODUs), even while operating in the ''tender assist'' mode (*i.e.*, with skid-off drilling units) or other vessels engaged in drilling or downhole operations. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc*. During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

Flaring means the burning of natural gas as it is released into the atmosphere.

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 associated gas-cap of an oil reservoir.

Geological and geophysical (G&G) explorations means those G&G surveys on your lease or unit that use seismic reflection, seismic refraction, magnetic, gravity, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur in commercial quantities.

Governor means the Governor of a State, or the person or entity designated by, or under, State law to exercise the powers granted to such Governor under the Act.

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 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.

Human environment means the physical, social, and economic components, conditions, and factors that 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.

Interpreted geological information means geological knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of data and analyzed geological information.

Interpreted geophysical information means geophysical knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geophysical data and analyzed geophysical information.

Lease means an agreement that is issued under section 8 or maintained under section 6 of the Act and that authorizes exploration for, and development and production of, minerals. The term also means the area covered by that authorization, whichever the context requires.

Lease term pipelines mean those pipelines owned and operated by a lessee or operator that are completely contained within the boundaries of a single lease, unit, or contiguous (not cornering) leases of that lessee or operator.

Lessee means a person who has entered into a lease with the United States to explore for, develop, and produce the leased minerals. The term lessee also includes the BOEM-approved assignee of the lease, and the owner or the BOEM-approved assignee of operating rights for the lease.

Major Federal action means any action or proposal by the Secretary that is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act of 1969, 42 U.S.C. (2)(C) (*i.e.*, an action that will have a significant impact on the quality of the human environment requiring preparation of an environmental impact statement under section 102(2)(C) of the National Environmental Policy Act).

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the productivity, state, condition, and quality of the marine ecosystem. These include 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 that 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.

Minerals include oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals that are authorized by an Act of Congress to be produced.

Natural resources include, without limiting the generality thereof, oil, gas, and all other minerals, and fish, shrimp, oysters, clams, crabs, lobsters, sponges, kelp, and other marine animal and plant life but does not include water power or the use of water for the production of power.

Nonattainment area means, for any criteria 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.

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.

Operating rights mean any interest held in a lease with the right to explore for, develop, and produce leased substances.

Operator means the person the lessee(s) designates as having control or management of operations on the leased area or a portion thereof. An operator may be a lessee, the BOEM-approved or BSEE-approved designated agent of the lessee(s), or the holder of operating rights under a BOEM-approved operating rights assignment.

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) whose subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person includes a natural person, an association (including partnerships, joint ventures, and trusts), a State, a political subdivision of a State, or a private, public, or municipal corporation.

Pipelines are the piping, risers, and appurtenances installed for transporting oil, gas, sulphur, and produced waters.

Processed geological or geophysical information means data collected under a permit or a lease that have been processed or reprocessed. Processing involves changing the form of data 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. Reprocessing is the additional processing other than ordinary processing used in the general

course of evaluation. Reprocessing operations may include varying identified parameters for the detailed study of a specific problem area.

Production means those activities that 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 workover operations.

Production areas are those areas where flammable petroleum gas, volatile liquids or sulphur are produced, processed (e.g., compressed), stored, transferred (e.g., pumped), or otherwise handled before entering the transportation process.

Projected emissions mean emissions, either controlled or uncontrolled, from a source or sources.

Prospect means a geologic feature having the potential for mineral deposits.

Regional Director means the BOEM officer with responsibility and authority for a Region within BOEM.

Regional Supervisor means the BOEM officer with responsibility and authority for operations or other designated program functions within a BOEM Region.

Right-of-use means any authorization issued under this part to use OCS lands.

Right-of-way pipelines are those pipelines that are contained within:

(1) The boundaries of a single lease or unit, but are not owned and operated by a lessee or operator of that lease or unit;

(2) The boundaries of contiguous (not cornering) leases that do not have a common lessee or operator;

(3) The boundaries of contiguous (not cornering) leases that have a common lessee or operator but are not owned and operated by that common lessee or operator; or

(4) An unleased block(s).

Sensitive reservoir means a reservoir in which the production rate will affect ultimate recovery.

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, or its successor.

Suspension means a granted or directed deferral of the requirement to produce (Suspension of Production (SOP)) or to conduct leaseholding operations (Suspension of Operations (SOO)).

Venting means the release of gas into the atmosphere without igniting it. This includes gas that is released underwater and bubbles to the atmosphere.

Volatile organic compound (VOC) means any organic compound that is emitted to the atmosphere as a vapor. Unreactive compounds are excluded from the preceding sentence of this definition.

Waste of oil, gas, or sulphur means:

(1) The physical waste of oil, gas, or sulphur;

(2) The inefficient, excessive, or improper use, 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 that causes or tends to cause a reduction in the quantity of oil, gas, or sulphur ultimately recoverable under prudent and proper operations or that causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or

(4) The inefficient storage of oil.

Welding means all activities connected with welding, including hot tapping and burning.

Wellbay is the area on a facility within the perimeter of the outermost wellheads.

Well-completion operations mean 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.

Western Gulf of Mexico means all OCS areas of the Gulf of Mexico except those the BOEM Director decides are adjacent to the State of Florida. The Western Gulf of Mexico is not the same as the Western Planning Area, an area established for OCS lease sales.

Workover operations mean the work conducted on wells after the initial well-completion operation for the purpose of maintaining or restoring the productivity of a well.

You means a lessee, the owner or holder of operating rights, a designated operator or agent of the lessee(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement.

[76 FR 64623, Oct. 18, 2011, as amended at 81 FR 46565, July 15, 2016; 85 FR 34935, June 5, 2020]

PERFORMANCE STANDARDS

§ 550.115 How do I determine well producibility?

You must follow the procedures in this section to determine well producibility if your well is not in the GOM. If your well is in the GOM you must follow the procedures in either this section or in § 550.116 of this subpart.

(a) You must write to the Regional Supervisor asking for permission to determine producibility.

(b) You must either:

(1) Allow the Regional Supervisor to witness each test that you conduct under this section; or

(2) Receive the Regional Supervisor prior approval so that you can submit either test data with your affidavit or third party test data.

(c) If the well is an oil well, you must conduct a production test that lasts at least 2 hours after flow stabilizes.

(d) If the well is a gas well, you must conduct a deliverability test that lasts at least 2 hours after flow stabilizes, or a four-point back pressure test.

§ 550.116 How do I determine producibility if my well is in the Gulf of Mexico?

If your well is in the GOM, you must follow either the procedures in § 550.115 of this subpart or the procedures in this section to determine producibility.

(a) You must write to the Regional Supervisor asking for permission to determine producibility.

(b) You must provide or make available to the Regional Supervisor, as requested, the following log, core, analyses, and test criteria that BOEM will consider collectively:

(1) A log showing sufficient porosity in the producible section.

(2) Sidewall cores and core analyses that show that the section is capable of producing oil or gas.

(3) Wireline formation test and/or mud-logging analyses that show that the section is capable of producing oil or gas.

(4) A resistivity or induction electric log of the well showing a minimum of 15 feet (true vertical thickness except for horizontal wells) of producible sand in one section.

(c) No section that you count as producible under paragraph (b)(4) of this section may include any interval that appears to be water saturated.

(d) Each section you count as producible under paragraph (b)(4) of this section must exhibit:

(1) A minimum true resistivity ratio of the producible section to the nearest clean or water-bearing sand of at least 5:1; and

(2) One of the following:

(i) Electrical spontaneous potential exceeding 20-negative millivolts beyond the shale baseline; or

(ii) Gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water-bearing sand—if mud conditions prevent a 20-negative millivolt reading beyond the shale baseline.

§ 550.117 How does a determination of well producibility affect royalty status?

A determination of well producibility invokes minimum royalty status on the lease as provided in 30 CFR 1202.53.

§ 550.118 [Reserved]

§ 550.119 Will BOEM approve subsurface gas storage?

The Regional Supervisor may authorize subsurface storage of gas on the OCS, on and off-lease, for later commercial benefit. The Regional Supervisor may authorize subsurface storage of gas on the OCS, off-lease, for later commercial benefit. To receive approval you must:

(a) Show that the subsurface storage of gas will not result in undue interference with operations under existing leases; and

(b) Sign a storage agreement that includes the required payment of a storage fee or rental.

§ 550.120 What standards will BOEM use to regulate leases, rights-of-use and easement, and rights-of-way?

BOEM will regulate all activities under a lease, a right-of-use and easement, or a right-of-way to:

(a) Promote the orderly exploration, development, and production of mineral resources;

(b) Prevent injury or loss of life;

(c) Prevent damage to or waste of any natural resource, property, or the environment; and

(d) Ensure cooperation and consultation with affected States, local governments, other interested parties, and relevant Federal agencies.

[81 FR 18152, Mar. 30, 2016]

§ 550.121 What must I do to protect health, safety, property, and the environment?

The Director may require additional measures to ensure the use of Best Available and Safest Technology (BAST) as identified by BSEE:

(a) To avoid the failure of equipment that would have a significant effect on safety, health, or the environment;

(b) If it is economically feasible; and

(c) If the incremental benefits justify the incremental costs.

[81 FR 18152, Mar. 30, 2016]

§ 550.122 What effect does subsurface storage have on the lease term?

If you use a lease area for subsurface storage of gas, it does not affect the continuance or expiration of the lease.

§ 550.123 Will BOEM allow gas storage on unleased lands?

You may not store gas on unleased lands unless the Regional Supervisor approves a right-of-use and easement for that purpose, under §§ 550.160 through 550.166 of this subpart.

FEES

§ 550.125 Service fees.

(a) The table in this paragraph (a) shows the fees that you must pay to BOEM for the services listed. The fees will be adjusted periodically according to the Implicit Price Deflator for Gross Domestic Product by publication of a document in the FEDERAL REGISTER. If a significant adjustment is needed to arrive at the new actual cost for any reason other than inflation, then a proposed rule containing the new fees will be published in the FEDERAL REGISTER for comment.

Service—processing of the following:	Fee amount	30 CFR citation
(1) Change in Designation of Operator	$164	§ 550.143(d).
(2) Right-of-Use and Easement for State lessee	$2,569	§ 550.165.
(3) [Reserved].		
(4) Exploration Plan (EP)	$3,442 for each surface location; no fee for revisions.	§ 550.211(d).
(5) Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD).	$3,971 for each well proposed; no fee for revisions	§ 550.241(e).
(6) [Reserved].		
(7) Conservation Information Document	$25,629	§ 550.296(a).

(b) Payment of the fees listed in paragraph (a) of this section must accompany the submission of the document for approval or be sent to an office identified by the Regional Director. Once a fee is paid, it is nonrefundable, even if an application or other request is withdrawn. If your application is returned to you as incomplete, you are not required to submit a new fee when you submit the amended application.

(c) Verbal approvals are occasionally given in special circumstances. Any action that will be considered a verbal permit approval requires either a paper permit application to follow the verbal approval or an electronic application

submittal within 72 hours. Payment must be made with the completed paper or electronic application.

§ 550.126 Electronic payment instructions.

You must file all payments electronically through *Pay.gov*. This includes, but is not limited to, all OCS applications or filing fee payments. The *Pay.gov* Web site may be accessed through *Pay.gov* at *https://www.pay.gov/paygov/*.

(a) [Reserved]

(b) You must use credit card or automated clearing house (ACH) payments through the *Pay.gov* Web site, and you must include a copy of the *Pay.gov* confirmation receipt page with your application.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

INSPECTION OF OPERATIONS

§ 550.130 [Reserved]

DISQUALIFICATION

§ 550.135 What will BOEM do if my operating performance is unacceptable?

If your operating performance is unacceptable, BOEM may disapprove or revoke your designation as operator on a single facility or multiple facilities. We will give you adequate notice and opportunity for a review by BOEM officials before imposing a disqualification.

§ 550.136 How will BOEM determine if my performance is unacceptable?

In determining if your operating performance is unacceptable, BOEM will consider, individually or collectively:

(a)–(b) [Reserved]

(c) Incidents of noncompliance;

(d) Civil penalties;

(e) Failure to adhere to OCS lease obligations; or

(f) Any other relevant factors.

SPECIAL TYPES OF APPROVALS

§ 550.140 When will I receive an oral approval?

When you apply for BOEM approval of any activity, we normally give you a written decision. The following table shows circumstances under which we may give an oral approval.

When you . . .	We may . . .	And . . .
(a) Request approval orally,	Give you an oral approval,	You must then confirm the oral request by sending us a written request within 72 hours.
(b) Request approval in writing,	Give you an oral approval if quick action is needed,	We will send you a written approval afterward. It will include any conditions that we place on the oral approval.

§ 550.141 May I ever use alternate procedures or equipment?

You may use alternate procedures or equipment after receiving approval as described in this section.

(a) Any alternate procedures or equipment that you propose to use must provide a level of safety and environmental protection that equals or surpasses current BOEM requirements.

(b) You must receive the Regional Supervisor's written approval before you can use alternate procedures or equipment.

(c) To receive approval, you must either submit information or give an oral presentation to the appropriate Regional Supervisor. Your presentation must describe the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment.

§ 550.142 How do I receive approval for departures?

We may approve departures to the operating requirements. You may apply for a departure by writing to the Regional Supervisor.

§ 550.143 How do I designate an operator?

(a) You must provide the Regional Supervisor an executed Designation of

Operator form (Form BOEM–1123) unless you are the only lessee and are the only person conducting lease operations. When there is more than one lessee, each lessee must submit the Designation of Operator form and the Regional Supervisor must approve the designation before the designated operator may begin operations on the leasehold.

(b) This designation is authority for the designated operator to act on your behalf and to fulfill your obligations under the Act, the lease, and the regulations in this part.

(c) You, or your designated operator, must immediately provide the Regional Supervisor a written notification of any change of address.

(d) If you change the designated operator on your lease, you must pay the service fee listed in § 550.125 of this subpart with your request for a change in designation of operator. Should there be multiple lessees, all designation of operator forms must be collected by one lessee and submitted to BOEM in a single submittal, which is subject to only one filing fee.

§ 550.144 How do I designate a new operator when a designation of operator terminates?

(a) When a Designation of Operator terminates, the Regional Supervisor must approve a new designated operator before you may continue operations. Each lessee must submit a new executed Designation of Operator form.

(b) If your Designation of Operator is terminated, or a controversy develops between you and your designated operator, you and your designated operator must protect the lessor's interests.

§ 550.146 How do I designate an agent or a local agent?

(a) You or your designated operator may designate for the Regional Supervisor's approval, or the Regional Director may require you to designate an agent empowered to fulfill your obligations under the Act, the lease, or the regulations in this part.

(b) You or your designated operator may designate for the Regional Supervisor's approval a local agent empowered to receive notices and submit requests, applications, notices, or supplemental information.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18152, Mar. 30, 2016]

§ 550.147 Who is responsible for fulfilling leasehold obligations?

(a) When you are not the sole lessee, you and your co-lessee(s) are jointly and severally responsible for fulfilling your obligations under the provisions of 30 CFR parts 250 through 282 and 30 CFR parts 550 through 582 unless otherwise provided in these regulations.

(b) If your designated operator fails to fulfill any of your obligations under 30 CFR parts 250 through 282 and 30 CFR parts 550 through 582, the Regional Supervisor may require you or any or all of your co-lessees to fulfill those obligations or other operational obligations under the Act, the lease, or the regulations.

(c) Whenever the regulations in 30 CFR parts 250 through 282 and 30 CFR parts 550 through 582 require the lessee to meet a requirement or perform an action, the lessee, operator (if one has been designated), and the person actually performing the activity to which the requirement applies are jointly and severally responsible for complying with the regulation.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18152, Mar. 30, 2016]

RIGHT-OF-USE AND EASEMENT

§ 550.160 When will BOEM grant me a right-of-use and easement, and what requirements must I meet?

BOEM may grant you a right-of-use and easement on leased and unleased lands on the OCS, if you meet these requirements:

(a) You must need the right-of-use and easement to construct and maintain platforms, artificial islands, and installations and other devices at an OCS site other than an OCS lease you own, that are:

(1) Permanently or temporarily attached to the seabed; and

(2) Used for conducting exploration, development, and production activities or other operations on or off lease; or

(3) Used for other purposes approved by BOEM.

(b) You must exercise the right-of-use and easement according to the regulations of this part;

(c) You must meet the requirements at 30 CFR 556.35 (Qualification of lessees); establish a regional Company File as required by BOEM; and must meet bonding requirements;

(d) If you apply for a right-of-use and easement on a leased area, you must notify the lessee and give her/him an opportunity to comment on your application; and

(e) You must receive BOEM approval for all platforms, artificial islands, and installations and other devices permanently or temporarily attached to the seabed.

(f) You must pay a rental amount as required by paragraph (g) of this section if:

(1) You obtain a right-of-use and easement after January 12, 2004; or

(2) You ask BOEM to modify your right-of-use and easement to change the footprint of the associated platform, artificial island, or installation or device.

(g) If you meet either of the conditions in paragraph (f) of this section, you must pay a rental amount to BOEM as shown in the following table:

If . . .	Then . . .
(1) Your right-of-use and easement site is located in water depths of less than 200 meters;	You must pay a rental of $5 per acre per year with a minimum of $450 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other equipment associated with the platform, artificial island, installation or device.
(2) Your right-of-use and easement site is located in water depths of 200 meters or greater;	You must pay a rental of $7.50 per acre per year with a minimum of $675 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other equipment associated with the platform, artificial island, or installation or device.

(h) You may make the rental payments required by paragraph (g)(1) and (g)(2) of this section on an annual basis, for a 5-year period, or for multiples of 5 years. You must make the first payment electronically through *Pay.gov* and you must include a copy of the *Pay.gov* confirmation receipt page with your right-of-use and easement application. You must make all subsequent payments before the respective time periods begin.

(i) *Late payments.* An interest charge will be assessed on unpaid and underpaid amounts from the date the amounts are due, in accordance with the provisions found in 30 CFR 1218.54. If you fail to make a payment that is late after written notice from BOEM, BOEM may initiate cancellation of the right-of-use grant and easement.

§ 550.161 What else must I submit with my application?

With your application, you must describe the proposed use giving:

(a) Details of the proposed uses and activities including access needs and special rights of use that you may need;

(b) A description of all facilities for which you are seeking authorization;

(c) A map or plat describing primary and alternate project locations; and

(d) A schedule for constructing any new facilities, drilling or completing any wells, anticipated production rates, and productive life of existing production facilities.

§ 550.162 May I continue my right-of-use and easement after the termination of any lease on which it is situated?

If your right-of-use and easement is on a lease, you may continue to exercise the right-of-use and easement after the lease on which it is situated terminates. You must only use the right-of-use and easement for the purpose that the grant specifies. All future lessees of that portion of the OCS on which your right-of-use and easement is situated must continue to recognize the right-of-use and easement for the purpose that the grant specifies.

§ 550.163 If I have a State lease, will BOEM grant me a right-of-use and easement?

(a) BOEM may grant a lessee of a State lease located adjacent to or accessible from the OCS a right-of-use and easement on the OCS.

(b) BOEM will only grant a right-of-use and easement under this paragraph to enable a State lessee to conduct and maintain a device that is permanently or temporarily attached to the seabed (*i.e.*, a platform, artificial island, or installation). The lessee must use the device to explore for, develop, and produce oil and gas from the adjacent or accessible State lease and for other operations related to these activities.

§ 550.164 If I have a State lease, what conditions apply for a right-of-use and easement?

(a) A right-of-use and easement granted under the heading of ''Right-of-use and easement'' in this subpart is subject to BOEM regulations, 30 CFR parts 550 through 582, BSEE regulations, 30 CFR parts 250 through 282, and any terms and conditions that the BOEM Regional Director or BSEE Regional Director prescribes.

(b) For the whole or fraction of the first calendar year, and annually after that, you must pay to BOEM, in advance, an annual rental payment.

§ 550.165 If I have a State lease, what fees do I have to pay for a right-of-use and easement?

When you apply for a right-of-use and easement, you must pay:

(a) A nonrefundable filing fee as specified in § 550.125; and

(b) The first year's rental as specified in § 550.160(g).

§ 550.166 If I have a State lease, what surety bond must I have for a right-of-use and easement?

(a) Before BOEM issues you a right-of-use and easement on the OCS, you must furnish the Regional Director a surety bond for $500,000.

(b) The Regional Director may require additional security from you (*i.e.*, security above the prescribed $500,000) to cover additional costs and liabilities for regulatory compliance. This additional surety:

(1) Must be in the form of a supplemental bond or bonds meeting the requirements of 30 CFR 556.54 (General requirements for bonds) or an increase in the coverage of an existing surety bond.

(2) Covers additional costs and liabilities for regulatory compliance, including well abandonment, platform and structure removal, and site clearance from the seafloor of the right-of-use and easement.

Primary Lease Requirements, Lease Term Extensions, and Lease Cancellations

§ 550.181 When may the Secretary cancel my lease and when am I compensated for cancellation?

If the Secretary cancels your lease under this part or under 30 CFR part 556, you are entitled to compensation under § 550.184. Section 550.185 states conditions under which you will receive no compensation. The Secretary may cancel a lease after notice and opportunity for a hearing when:

(a) Continued activity on the lease would probably cause harm or damage to life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment;

(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 cancellation outweigh the advantages of continuing the lease in force; and

(d) A suspension has been in effect for at least 5 years or you request termination of the suspension and lease cancellation.

§ 550.182 When may the Secretary cancel a lease at the exploration stage?

BOEM may not approve an exploration plan (EP) under 30 CFR part 550, subpart B, if the Regional Supervisor determines that the proposed activities may cause serious harm or damage to life (including fish and other aquatic life), property, any mineral deposits, the National security or defense, or to the marine, coastal, or human environment, and that the proposed activity cannot be modified to avoid the condition(s). The Secretary may cancel the lease if:

(a) The primary lease term has not expired (or if the lease term has been extended) and exploration has been prohibited for 5 years following the disapproval; or

(b) You request cancellation at an earlier time.

§ 550.183 When may BOEM or the Secretary extend or cancel a lease at the development and production stage?

(a) BOEM may extend your lease if you submit a DPP and the Regional Supervisor disapproves the plan according to the regulations in 30 CFR part 550, subpart B. Following the disapproval:

(1) BOEM will allow you to hold the lease for 5 years, or less time at your request;

(2) Any time within 5 years after the disapproval, you may reapply for approval of the same or a modified plan; and

(3) The Regional Supervisor will approve, disapprove, or require modification of the plan under 30 CFR part 550, subpart B.

(b) If the Regional Supervisor has not approved a DPP or required you to submit a DPP for approval or modification, the Secretary will cancel the lease:

(1) When the 5-year period in paragraph (a)(1) of this section expires; or

(2) If you request cancellation at an earlier time.

§ 550.184 What is the amount of compensation for lease cancellation?

When the Secretary cancels a lease under §§ 550.181, 550.182 or 550.183 of this subpart, you are entitled to receive compensation under 43 U.S.C. 1334(a)(2)(C). You must show the Director that the amount of compensation claimed is the lesser of paragraph (a) or (b) of this section:

(a) The fair value of the cancelled rights as of the date of cancellation, taking into account both:

(1) Anticipated revenues from the lease; and

(2) Costs reasonably anticipated on the lease, including:

(i) Costs of compliance with all applicable regulations and operating orders; and

(ii) Liability for cleanup costs or damages, or both, in the case of an oil spill.

(b) The excess, if any, over your revenues from the lease (plus interest thereon from the date of receipt to date of reimbursement) of:

(1) All consideration paid for the lease (plus interest from the date of payment to the date of reimbursement); and

(2) All your direct expenditures (plus interest from the date of payment to the date of reimbursement):

(i) After the issue date of the lease; and

(ii) For exploration or development, or both.

(c) Compensation for leases issued before September 18, 1978, will be equal to the amount specified in paragraph (a) of this section.

§ 550.185 When is there no compensation for a lease cancellation?

You will not receive compensation from BOEM for lease cancellation if:

(a) BOEM disapproves a DPP because you do not receive concurrence by the State under 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;

(b) You do not submit a DPP under 30 CFR part 550, subpart B or do not comply with the approved DPP;

(c) As the lessee of a nonproducing lease, you fail to comply with the Act, the lease, or the regulations issued under the Act, and the default continues for 30 days after BOEM mails you a notice by overnight mail;

(d) The Regional Supervisor disapproves a DPP because you fail to comply with the requirements of applicable Federal law; or

(e) The Secretary forfeits and cancels a producing lease under section 5(d) of the Act (43 U.S.C. 1334(d)).

INFORMATION AND REPORTING REQUIREMENTS

§ 550.186 What reporting information and report forms must I submit?

(a) You must submit information and reports as BOEM requires.

(1) You may obtain copies of forms from, and submit completed forms to, the Regional Supervisor.

(2) Instead of paper copies of forms available from the Regional Supervisor, you may use your own computer-generated forms that are equal in size to BOEM's forms. You must arrange the data on your form identical to the

BOEM form. If you generate your own form and it omits terms and conditions contained on the official BOEM form, we will consider it to contain the omitted terms and conditions.

(3) You may submit digital data when the Region is equipped to accept it.

(b) When BOEM specifies, you must include, for public information, an additional copy of such reports.

(1) You must mark it *Public Information*.

(2) You must include all required information, except information exempt from public disclosure under § 550.197 or otherwise exempt from public disclosure under law or regulation.

§§ 550.187–550.193 [Reserved]

§ 550.194 How must I protect archaeological resources?

(a) If the Regional Director has reason to believe that an archaeological resource may exist in the lease area, the Regional Director will require in writing that your EP, DOCD, or DPP be accompanied by an archaeological report. If the archaeological report suggests that an archaeological resource may be present, you must either:

(1) Locate the site of any operation so as not to adversely affect the area where the archaeological resource may be; or

(2) Establish to the satisfaction of the Regional Director that an archaeological resource does not exist or will not be adversely affected by operations. This requires further archaeological investigation, conducted by an archaeologist and a geophysicist, using survey equipment and techniques the Regional Director considers appropriate. You must submit the investigation report to the Regional Director for review.

(b) 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 you immediately. You must not take any action that may adversely affect the archaeological resource until the Regional Director has told you how to protect the resource.

(c) If you discover any archaeological resource while conducting operations in the lease or right-of-way area, you must immediately halt operations within the area of the discovery and report the discovery to the BOEM Regional Director. If investigations determine that the resource is significant, the Regional Director will tell you how to protect it.

§ 550.195 [Reserved]

§ 550.196 Reimbursements for reproduction and processing costs.

(a) BOEM will reimburse you for costs of reproducing data and information that the Regional Director requests if:

(1) You deliver geophysical and geological (G&G) data and information to BOEM for the Regional Director to inspect or select and retain;

(2) BOEM receives your request for reimbursement and the Regional Director determines that the requested reimbursement is proper; and

(3) The cost is at your lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) BOEM will reimburse you for the costs of processing geophysical information (that does not include cost of data acquisition):

(1) If, at the request of the Regional Director, you processed the geophysical data or information in a form or manner other than that used in the normal conduct of business; or

(2) If you collected the information under a permit that BOEM issued to you before October 1, 1985, and the Regional Director requests and retains the information.

(c) When you request reimbursement, you must identify reproduction and processing costs separately from acquisition costs.

(d) BOEM will not reimburse you for data acquisition costs or for the costs of analyzing or processing geological information or interpreting geological or geophysical information.

§ 550.197 Data and information to be made available to the public or for limited inspection.

BOEM will protect data and information that you submit under this chapter, as described in this section. Paragraphs (a) and (b) of this section describe what data and information will be made available to the public without the consent of the lessee, under what circumstances, and in what time period. Paragraph (c) of this section describes what data and information will be made available for limited inspection without the consent of the lessee, and under what circumstances.

(a) All data and information you submit on BOEM forms will be made available to the public upon submission, except as specified in the following table:

On form . . .	Data and information not immediately available are . . .	Excepted data will be made available . . .
(1) [Reserved]		
(2) [Reserved]		
(3) [Reserved]		
(4) [Reserved]		
(5) [Reserved]		
(6) BOEM–0127, Sensitive Reservoir Information Report,	Items 124 through 168,	2 years after the effective date of the Sensitive Reservoir Information Report.
(7) [Reserved]		
(8) [Reserved]		
(9) BOEM–0137 OCS Plan Information,	Items providing the bottomhole location, true vertical depth, and measured depth of wells,	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(10) BOEM–0140, Bottomhole Pressure Survey Report,	All items,	2 years after the date of the survey.

(b) BOEM will release lease and permit data and information that you submit and BOEM retains, but that are not normally submitted on BOEM forms, according to the following table:

If . . .	BOEM will release . . .	At this time . . .	Special provisions . . .
(1) The Director determines that data and information are needed for specific scientific or research purposes for the Government,	Geophysical data, Geological data Interpreted G&G information, Processed G&G information, Analyzed geological information,	At any time,	BOEM will release data and information only if release would further the National interest without unduly damaging the competitive position of the lessee.
(2) Data or information is collected with high-resolution systems (e.g., bathymetry, side-scan sonar, subbottom profiler, and magnetometer) to comply with safety or environmental protection requirements,	Geophysical data, Geological data, Interpreted G&G information, Processed geological information, Analyzed geological information,	60 days after BOEM receives the data or information, if the Regional Supervisor deems it necessary,	BOEM will release the data and information earlier than 60 days if the Regional Supervisor determines it is needed by affected States to make decisions under subpart B. The Regional Supervisor will reconsider earlier release if you satisfy him/her that it would unduly damage your competitive position.
(3) Your lease is no longer in effect,	Geophysical data, Geological data, Processed G&G information Interpreted G&G information, Analyzed geological information,	When your lease terminates,	This release time applies only if the provisions in this table governing high-resolution systems and the provisions in § 552.7 do not apply. The release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.

If . . .	BOEM will release . . .	At this time . . .	Special provisions . . .
(4) Your lease is still in effect,	Geophysical data, Processed geophysical information, Interpreted G&G information,	10 years after you submit the data and information,	This release time applies only if the provisions in this table governing high-resolution systems and the provisions in § 552.7 do not apply. This release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.
(5) Your lease is still in effect and within the primary term specified in the lease	Geological data, analyzed geological information	Two years after the required submittal date or 60 days after a lease sale if any portion of an offered lease is within 50 miles of a well, whichever is later	These release times apply only if the provisions in this table governing high-resolution systems and the provisions in § 552.7 do not apply. If the primary term specified in the lease is extended, this provision applies to the extension.
(6) Your lease is in effect and beyond the primary term specified in the lease,	Geological data, Analyzed geological information,	2 years after the required submittal date,	None.
(7) Data or information is submitted on well operations,	Descriptions of downhole locations, operations, and equipment,	When the well goes on production or when geological data is released according to §§ 550.197(b)(5) and (b)(6), whichever occurs earlier,	Directional survey data may be released earlier to the owner of an adjacent lease according to 30 CFR 250 subpart D.
(8) Data and information are obtained from beneath unleased land as a result of a well deviation that has not been approved by the Regional Supervisor,	Any data or information obtained,	At any time,	None.
(9) Except for high-resolution data and information released under paragraph (b)(2) of this section data and information acquired by a permit under 30 CFR part 551 are submitted by a lessee under part 550, 30 CFR part 203, or 30 CFR part 250,	G&G data, analyzed geological information, processed and interpreted G&G information,	Geological data and information: 10 years after BOEM issues the permit; Geophysical data: 50 years after BOEM issues the permit; Geophysical information: 25 years after BOEM issues the permit,	None.

(c) BOEM may allow limited data and information inspection, but only by a person with a direct interest in related BOEM decisions and issues in a specific geographic area, and who agrees in writing to maintain the confidentiality of geological and geophysical (G&G) data and information submitted under this part that BOEM uses to:

(1) Promote operational safety;

(2) Protect the environment; or

(3) Make field determinations.

(d) No proprietary information received by BOEM under 43 U.S.C. 1352 will be transmitted to any affected State unless the lessee, or the permittee and all persons to whom such permittee has sold such information under promise of confidentiality, agree to such transmittal.

[76 FR 64623, Oct. 18, 2011, as amended at 81 FR 18152, Mar. 30, 2016]

REFERENCES

§ 550.198 [Reserved]

§ 550.199 Paperwork Reduction Act statements—information collection.

(a) OMB has approved the information collection requirements in part 550 under 44 U.S.C. 3501 *et seq*. The table in paragraph (e) of this section lists the subpart in the rule requiring the information and its title, provides the OMB control number, and summarizes the reasons for collecting the information and how BOEM uses the information. The associated BOEM forms required

by this part are listed at the end of this table with the relevant information.

(b) Respondents are OCS oil, gas, and sulphur lessees and operators. The requirement to respond to the information collections in this part is mandated under the Act (43 U.S.C. 1331 *et seq.*) and the Act's Amendments of 1978 (43 U.S.C. 1801 *et seq.*). Some responses are also required to obtain or retain a benefit or may be voluntary. Proprietary information will be protected under § 550.197, Data and information to be made available to the public or for limited inspection; parts 551, 552; and the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations at 43 CFR part 2.

(c) The Paperwork Reduction Act of 1995 requires us to inform the public that 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.

(d) Send comments regarding any aspect of the collections of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

(e) BOEM is collecting this information for the reasons given in the following table:

30 CFR subpart, title and/or BOEM Form (OMB Control No.)	Reasons for collecting information and how used
(1) Subpart A, General (1010–0114), including Forms BOEM–1123, Designation of Operator and BOEM–1832, Notification of Incidents of Noncompliance.	To inform BOEM of actions taken to comply with general requirements on the OCS. To ensure that operations on the OCS meet statutory and regulatory requirements, are safe and protect the environment, and result in diligent exploration, development, and production on OCS leases. To support the unproved and proved reserve estimation, resource assessment, and fair market value determinations.
(2) Subpart B, Exploration and Development and Production Plans (1010–0151), including Forms BOEM–0137, OCS Plan Information Form; BOEM–0138, EP Air Quality Screening Checklist; BOEM–0139, DOCD Air Quality Screening Checklist; BOEM–0141, ROV Survey Report Form; and BOEM–0142, Environmental Impact Analysis Worksheet.	To inform BOEM, States, and the public of planned exploration, development, and production operations on the OCS. To ensure that operations on the OCS are planned to comply with statutory and regulatory requirements, will be safe and protect the human, marine, and coastal environment, and will result in diligent exploration, development, and production of leases.
(3) Subpart C, Pollution Prevention and Control (1010–0057) ...	To inform BOEM of measures to be taken to prevent air pollution. To ensure that appropriate measures are taken to prevent air pollution.
(4) Subpart J, Pipelines and Pipeline Rights-of-Way (1010–0050), including Form BOEM–2030, Outer Continental Shelf (OCS) Pipeline Right-of-Way Grant Bond.	To provide BOEM with information regarding the design, installation, and operation of pipelines on the OCS. To ensure that pipeline operations are safe and protect the human, marine, and coastal environment.
(5) Subpart K, Oil and Gas Production Rates (1010–0041), including Forms BOEM–0127, Sensitive Reservoir Information Report and BOEM–0140, Bottomhole Pressure Survey Report.	To inform BOEM of production rates for hydrocarbons produced on the OCS. To ensure economic maximization of ultimate hydrocarbon recovery.
(6) Subpart N, Remedies and Penalties	The requirements in subpart N are exempt from the Paperwork Reduction Act of 1995 according to 5 CFR 1320.4.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

Subpart B—Plans and Information

GENERAL INFORMATION

§ 550.200 Definitions.

Acronyms and terms used in this subpart have the following meanings:

(a) *Acronyms* used frequently in this subpart are listed alphabetically below:

BOEM means Bureau of Ocean Energy Management.

BSEE means Bureau of Safety and Environmental Enforcement.

CID means Conservation Information Document.

CZMA means Coastal Zone Management Act.

DOCD means Development Operations Coordination Document.

DPP means Development and Production Plan.

DWOP means Deepwater Operations Plan.

EIA means Environmental Impact Analysis.

EP means Exploration Plan.

IOP means Integrated Operations Plan.

NPDES means National Pollutant Discharge Elimination System.

NTL means Notice to Lessees and Operators.

OCS means Outer Continental Shelf.

(b) Terms used in this subpart are listed alphabetically below:

Amendment means a change you make to an EP, DPP, or DOCD that is pending before BOEM for a decision (see §§ 550.232(d) and 550.267(d)).

Modification means a change required by the Regional Supervisor to an EP, DPP, or DOCD (see § 550.233(b)(2) and § 550.270(b)(2)) that is pending before BOEM for a decision because the OCS plan is inconsistent with applicable requirements.

New or unusual technology means equipment or procedures that:

(1) Have not been used previously or extensively in a BOEM OCS Region;

(2) Have not been used previously under the anticipated operating conditions; or

(3) Have operating characteristics that are outside the performance parameters established by this part.

Non-conventional production or completion technology includes, but is not limited to, floating production systems, tension leg platforms, spars, floating production, storage, and offloading systems, guyed towers, compliant towers, subsea manifolds, and other subsea production components that rely on a remote site or host facility for utility and well control services.

Offshore vehicle means a vehicle that is capable of being driven on ice.

Resubmitted OCS plan means an EP, DPP, or DOCD that contains changes you make to an OCS plan that BOEM has disapproved (see §§ 550.234(b), 550.272(a), and 550.273(b)).

Revised OCS plan means an EP, DPP, or DOCD that proposes changes to an approved OCS plan, such as those in the location of a well or platform, type of drilling unit, or location of the onshore support base (see § 550.283(a)).

Supplemental OCS plan means an EP, DPP, or DOCD that proposes the addition to an approved OCS plan of an activity that requires approval of an application or permit (see § 550.283(b)).

[76 FR 64623, Oct. 18, 2011, as amended at 81 FR 46565, July 15, 2016]

§ 550.201 What plans and information must I submit before I conduct any activities on my lease or unit?

(a) *Plans and documents.* Before you conduct the activities on your lease or unit listed in the following table, you must submit, and BOEM must approve, the listed plans and documents. Your plans and documents may cover one or more leases or units.

You must submit a(n) . . .	Before you . . .
(1) Exploration Plan (EP),	Conduct any exploration activities on a lease or unit.
(2) Development and Production Plan (DPP),	Conduct any development and production activities on a lease or unit in any OCS area other than the Western Gulf of Mexico.
(3) Development Operations Coordination Document (DOCD),	Conduct any development and production activities on a lease or unit in the Western GOM.
(4) BSEE approved Deepwater Operations Plan (DWOP),	Conduct post-drilling installation activities in any water depth associated with a development project that will involve the use of a non-conventional production or completion technology.
(5) Conservation Information Document (CID),	Commence production from development projects in water depths greater than 1,312 feet (400 meters).
(6) EP, DPP, or DOCD,	Conduct geological or geophysical (G&G) exploration or a development G&G activity (see definitions under § 550.105) on your lease or unit when: (i) It will result in a physical penetration of the seabed greater than 500 feet (152 meters); (ii) It will involve the use of explosives; (iii) The Regional Director determines that it might have a significant adverse effect on the human, marine, or coastal environment; or (iv) The Regional Supervisor, after reviewing a notice under § 550.209, determines that an EP, DPP, or DOCD is necessary.

(b) *Submitting additional information.* On a case-by-case basis, the Regional Supervisor may require you to submit additional information if the Regional

Supervisor determines that it is necessary to evaluate your proposed plan or document.

(c) *Limiting information.* The Regional Director may limit the amount of information or analyses that you otherwise must provide in your proposed plan or document under this subpart when:

(1) Sufficient applicable information or analysis is readily available to BOEM;

(2) Other coastal or marine resources are not present or affected;

(3) Other factors such as technological advances affect information needs; or

(4) Information is not necessary or required for a State to determine consistency with their CZMA Plan.

(d) *Referencing.* In preparing your proposed plan or document, you may reference information and data discussed in other plans or documents you previously submitted or that are otherwise readily available to BOEM.

§ 550.202 What criteria must the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) meet?

Your EP, DPP, or DOCD must demonstrate that you have planned and are prepared to conduct the proposed activities in a manner that:

(a) Conforms to the Outer Continental Shelf Lands Act as amended (Act), applicable implementing regulations, lease provisions and stipulations, and other Federal laws;

(b) Is safe;

(c) Conforms to sound conservation practices and protects the rights of the lessor;

(d) Does not unreasonably interfere with other uses of the OCS, including those involved with National security or defense; and

(e) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.

§ 550.203 Where can wells be located under an EP, DPP, or DOCD?

The Regional Supervisor reviews and approves proposed well location and spacing under an EP, DPP, or DOCD. In deciding whether to approve a proposed well location and spacing, the Regional Supervisor will consider factors including, but not limited to, the following:

(a) Protecting correlative rights;

(b) Protecting Federal royalty interests;

(c) Recovering optimum resources;

(d) Number of wells that can be economically drilled for proper reservoir management;

(e) Location of drilling units and platforms;

(f) Extent and thickness of the reservoir;

(g) Geologic and other reservoir characteristics;

(h) Minimizing environmental risk;

(i) Preventing unreasonable interference with other uses of the OCS; and

(j) Drilling of unnecessary wells.

§ 550.204 When must I submit my IOP for proposed Arctic exploratory drilling operations and what must the IOP include?

If you propose exploratory drilling activities on the Arctic OCS, you must submit an Integrated Operations Plan (IOP) to the Regional Supervisor at least 90 days prior to filing your EP. Your IOP must describe how your exploratory drilling program will be designed and conducted in an integrated manner that accounts for Arctic OCS conditions and include the following information:

(a) A description of how all vessels and equipment will be designed, built, and/or modified to account for Arctic OCS conditions;

(b) A schedule of your exploratory drilling program, including contractor work on critical components of your program;

(c) A description of your mobilization and demobilization operations, including tow plans that account for Arctic OCS conditions, as well as your general maintenance schedule for vessels and equipment;

(d) A description of your exploratory drilling program objectives and timelines for each objective, including general plans for abandonment of the well(s), such as:

(1) Contingency plans for temporary abandonment in the event of ice encroachment at the drill site;

(2) Plans for permanent abandonment; and

(3) Plans for temporary seasonal abandonment.

(e) A description of your weather and ice forecasting capabilities for all phases of the exploration program, including a description of how you would respond to and manage ice hazards and weather events;

(f) A description of work to be performed by contractors supporting your exploration drilling program (including mobilization and demobilization), including:

(1) How such work will be designed or modified to account for Arctic OCS conditions; and

(2) Your concepts for contractor management, oversight, and risk management.

(g) A description of how you will ensure operational safety while working in Arctic OCS conditions, including but not limited to:

(1) The safety principles that you intend to apply to yourself and your contractors;

(2) The accountability structure within your organization for implementing such principles;

(3) How you will communicate such principles to your employees and contractors; and

(4) How you will determine successful implementation of such principles.

(h) Information regarding your preparations and plans for staging of oil spill response assets;

(i) A description of your efforts to minimize impacts of your exploratory drilling operations on local community infrastructure, including but not limited to housing, energy supplies, and services; and

(j) A description of whether and to what extent your project will rely on local community workforce and spill cleanup response capacity.

[81 FR 46565, July 15, 2016]

§ 550.205 [Reserved]

§ 550.206 How do I submit the IOP, EP, DPP, or DOCD?

(a) *Number of copies.* When you submit an IOP, EP, DPP, or DOCD to BOEM, you must provide:

(1) Four copies that contain all required information (proprietary copies);

(2) Eight copies for public distribution (public information copies) that omit information that you assert is exempt from disclosure under the Freedom of Information Act (FOIA) (5 U.S.C. 552) and the implementing regulations (43 CFR part 2); and

(3) Any additional copies that may be necessary to facilitate review of the IOP, EP, DPP, or DOCD by certain affected States and other reviewing entities.

(b) *Electronic submission.* You may submit part or all of your IOP, EP, DPP, or DOCD and its accompanying information electronically. If you prefer to submit your IOP, EP, DPP, or DOCD electronically, ask the Regional Supervisor for further guidance.

(c) *Withdrawal after submission.* You may withdraw your proposed IOP, EP, DPP, or DOCD at any time for any reason. Notify the appropriate BOEM OCS Region if you do.

[81 FR 46565, July 15, 2016]

ANCILLARY ACTIVITIES

§ 550.207 What ancillary activities may I conduct?

Before or after you submit an EP, DPP, or DOCD to BOEM, you may elect, the regulations in this part may require, or the Regional Supervisor may direct you to conduct ancillary activities. Ancillary activities include:

(a) Geological and geophysical (G&G) explorations and development G&G activities;

(b) Geological and high-resolution geophysical, geotechnical, archaeological, biological, physical oceanographic, meteorological, socioeconomic, or other surveys; or

(c) Studies that model potential oil and hazardous substance spills, drilling muds and cuttings discharges, projected air emissions, or potential hydrogen sulfide (H_2S) releases.

§ 550.208 If I conduct ancillary activities, what notices must I provide?

At least 30 calendar days before you conduct any G&G exploration or development G&G activity (see § 550.207(a)), you must notify the Regional Supervisor in writing.

(a) When you prepare the notice, you must:

(1) Sign and date the notice;

(2) Provide the names of the vessel, its operator, and the person(s) in charge; the specific type(s) of operations you will conduct; and the instrumentation/techniques and vessel navigation system you will use;

(3) Provide expected start and completion dates and the location of the activity; and

(4) Describe the potential adverse environmental effects of the proposed activity and any mitigation to eliminate or minimize these effects on the marine, coastal, and human environment.

(b) The Regional Supervisor may require you to:

(1) Give written notice to BOEM at least 15 calendar days before you conduct any other ancillary activity (see § 550.207(b) and (c)) in addition to those listed in § 550.207(a); and

(2) Notify other users of the OCS before you conduct any ancillary activity.

§ 550.209 What is the BOEM review process for the notice?

The Regional Supervisor will review any notice required under § 550.208(a) and (b)(1) to ensure that your ancillary activity complies with the performance standards listed in § 550.202(a), (b), (d), and (e). The Regional Supervisor may notify you that your ancillary activity does not comply with those standards. In such a case, the Regional Supervisor will require you to submit an EP, DPP, or DOCD and you may not start your ancillary activity until the Regional Supervisor approves the EP, DPP, or DOCD.

§ 550.210 If I conduct ancillary activities, what reporting and data/information retention requirements must I satisfy?

(a) *Reporting*. The Regional Supervisor may require you to prepare and submit reports that summarize and analyze data or information obtained or derived from your ancillary activities. When applicable, BOEM will protect and disclose the data and information in these reports in accordance with § 550.197(b).

(b) *Data and information retention*. You must retain copies of all original data and information, including navigation data, obtained or derived from your G&G explorations and development G&G activities (see § 550.207(a)), including any such data and information you obtained from previous leaseholders or unit operators. You must submit such data and information to BOEM for inspection and possible retention upon request at any time before lease or unit termination. When applicable, BOEM will protect and disclose such submitted data and information in accordance with § 550.197(b).

CONTENTS OF EXPLORATION PLANS (EP)

§ 550.211 What must the EP include?

Your EP must include the following:

(a) *Description, objectives, and schedule*. A description, discussion of the objectives, and tentative schedule (from start to completion) of the exploration activities that you propose to undertake. Examples of exploration activities include exploration drilling, well test flaring, installing a well protection structure, and temporary well abandonment.

(b) *Location*. A map showing the surface location and water depth of each proposed well and the locations of all associated drilling unit anchors.

(c) *Drilling unit*. A description of the drilling unit and associated equipment you will use to conduct your proposed exploration activities, including a brief description of its important safety and pollution prevention features, and a table indicating the type and the estimated maximum quantity of fuels, oil, and lubricants that will be stored on the facility (see definition of ''facility'' under § 550.105(3)).

(d) *Service fee*. You must include payment of the service fee listed in § 550.125.

§ 550.212 What information must accompany the EP?

The following information must accompany your EP:

(a) General information required by § 550.213;

(b) Geological and geophysical (G&G) information required by § 550.214;

(c) Hydrogen sulfide information required by § 550.215;

(d) Biological, physical, and socioeconomic information required by § 550.216;

(e) Solid and liquid wastes and discharges information and cooling water intake information required by § 550.217;

(f) Air emissions information required by § 550.218;

(g) Oil and hazardous substance spills information required by § 550.219;

(h) Alaska planning information required by § 550.220;

(i) Environmental monitoring information required by § 550.221;

(j) Lease stipulations information required by § 550.222;

(k) Mitigation measures information required by § 550.223;

(l) Support vessels and aircraft information required by § 550.224;

(m) Onshore support facilities information required by § 550.225;

(n) Coastal zone management information required by § 550.226;

(o) Environmental impact analysis information required by § 550.227; and

(p) Administrative information required by § 550.228.

§ 550.213 What general information must accompany the EP?

The following general information must accompany your EP:

(a) *Applications and permits*. A listing, including filing or approval status, of the Federal, State, and local application approvals or permits you must obtain to conduct your proposed exploration activities.

(b) *Drilling fluids*. A table showing the projected amount, discharge rate, and chemical constituents for each type (*i.e.*, water-based, oil-based, synthetic-based) of drilling fluid you plan to use to drill your proposed exploration wells.

(c) *Chemical products*. A table showing the name and brief description, quantities to be stored, storage method, and rates of usage of the chemical products you will use to conduct your proposed exploration activities. List only those chemical products you will store or use in quantities greater than the amounts defined as Reportable Quantities in 40 CFR part 302, or amounts specified by the Regional Supervisor.

(d) *New or unusual technology*. A description and discussion of any new or unusual technology (see definition under § 550.200) you will use to carry out your proposed exploration activities. In the public information copies of your EP, you may exclude any proprietary information from this description. In that case, include a brief discussion of the general subject matter of the omitted information. If you will not use any new or unusual technology to carry out your proposed exploration activities, include a statement so indicating.

(e) *Bonds, oil spill financial responsibility, and well control statements*. Statements attesting that:

(1) The activities and facilities proposed in your EP are or will be covered by an appropriate bond under 30 CFR part 556, subpart I;

(2) You have demonstrated or will demonstrate oil spill financial responsibility for facilities proposed in your EP according to 30 CFR part 553; and

(3) You have or will have the financial capability to drill a relief well and conduct other emergency well control operations.

(f) *Suspensions of operations*. A brief discussion of any suspensions of operations that you anticipate may be necessary in the course of conducting your activities under the EP.

(g) *Blowout scenario*. A scenario for the potential blowout of the proposed well in your EP that you expect will have the highest volume of liquid hydrocarbons. Include the estimated flow rate, total volume, and maximum duration of the potential blowout. Also, discuss the potential for the well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Estimate the time it would take to drill a relief well.

(h) *Contact*. The name, address (e-mail address, if available), and telephone number of the person with whom the Regional Supervisor and any affected State(s) can communicate about your EP.

§ 550.214 What geological and geophysical (G&G) information must accompany the EP?

The following G&G information must accompany your EP:

(a) *Geological description.* A geological description of the prospect(s).

(b) *Structure contour maps.* Current structure contour maps (depth-based, expressed in feet subsea) drawn on the top of each prospective hydrocarbon-bearing reservoir showing the locations of proposed wells.

(c) *Two-dimensional (2–D) or three-dimensional (3–D) seismic lines.* Copies of migrated and annotated 2–D or 3–D seismic lines (with depth scale) intersecting at or near your proposed well locations. You are not required to conduct both 2–D and 3–D seismic surveys if you choose to conduct only one type of survey. If you have conducted both types of surveys, the Regional Supervisor may instruct you to submit the results of both surveys. You must interpret and display this information. Because of its volume, provide this information as an enclosure to only one proprietary copy of your EP.

(d) *Geological cross-sections.* Interpreted geological cross-sections showing the location and depth of each proposed well.

(e) *Shallow hazards report.* A shallow hazards report based on information obtained from a high-resolution geophysical survey, or a reference to such report if you have already submitted it to the Regional Supervisor.

(f) *Shallow hazards assessment.* For each proposed well, an assessment of any seafloor and subsurface geological and manmade features and conditions that may adversely affect your proposed drilling operations.

(g) *High-resolution seismic lines.* A copy of the high-resolution survey line closest to each of your proposed well locations. Because of its volume, provide this information as an enclosure to only one proprietary copy of your EP. You are not required to provide this information if the surface location of your proposed well has been approved in a previously submitted EP, DPP, or DOCD.

(h) *Stratigraphic column.* A generalized biostratigraphic/lithostratigraphic column from the surface to the total depth of the prospect.

(i) *Time-versus-depth chart.* A seismic travel time-versus-depth chart based on the appropriate velocity analysis in the area of interpretation and specifying the geodetic datum.

(j) *Geochemical information.* A copy of any geochemical reports you used or generated.

(k) *Future G&G activities.* A brief description of the types of G&G explorations and development G&G activities you may conduct for lease or unit purposes after your EP is approved.

§ 550.215 What hydrogen sulfide (H_2S) information must accompany the EP?

The following H_2S information, as applicable, must accompany your EP:

(a) *Concentration.* The estimated concentration of any H_2S you might encounter while you conduct your proposed exploration activities.

(b) *Classification.* Under 30 CFR 250.490(c), a request that the BSEE Regional Supervisor classify the area of your proposed exploration activities as either H_2S absent, H_2S present, or H_2S unknown. Provide sufficient information to justify your request.

(c) *H_2S Contingency Plan.* If you ask the Regional Supervisor to classify the area of your proposed exploration activities as either H_2S present or H_2S unknown, an H_2S Contingency Plan prepared under 30 CFR 250.490(f), or a reference to an approved or submitted H_2S Contingency Plan that covers the proposed exploration activities.

(d) *Modeling report.* If you modeled a potential H_2S release when developing your EP, modeling report or the modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(1) The analysis in the modeling report must be specific to the particular site of your proposed exploration activities, and must consider any nearby human-occupied OCS facilities, shipping lanes, fishery areas, and other points where humans may be subject to potential exposure from an H_2S release from your proposed exploration activities.

(2) If any H_2S emissions are projected to affect an onshore location in concentrations greater than 10 parts per million, the modeling analysis must be consistent with the Environmental Protection Agency's (EPA) risk management plan methodologies outlined in 40 CFR part 68.

§ 550.216 What biological, physical, and socioeconomic information must accompany the EP?

If you obtain the following information in developing your EP, or if the Regional Supervisor requires you to obtain it, you must include a report, or the information obtained, or a reference to such a report or information if you have already submitted it to the Regional Supervisor, as accompanying information:

(a) *Biological environment reports.* Site-specific information on chemosynthetic communities, federally listed threatened or endangered species, marine mammals protected under the Marine Mammal Protection Act (MMPA), sensitive underwater features, marine sanctuaries, critical habitat designated under the Endangered Species Act (ESA), or other areas of biological concern.

(b) *Physical environment reports.* Site-specific meteorological, physical oceanographic, geotechnical reports, or archaeological reports (if required under § 550.194).

(c) *Socioeconomic study reports.* Socioeconomic information regarding your proposed exploration activities.

§ 550.217 What solid and liquid wastes and discharges information and cooling water intake information must accompany the EP?

The following solid and liquid wastes and discharges information and cooling water intake information must accompany your EP:

(a) *Projected wastes.* A table providing the name, brief description, projected quantity, and composition of solid and liquid wastes (such as spent drilling fluids, drill cuttings, trash, sanitary and domestic wastes, and chemical product wastes) likely to be generated by your proposed exploration activities. Describe:

(1) The methods you used for determining this information; and

(2) Your plans for treating, storing, and downhole disposal of these wastes at your drilling location(s).

(b) *Projected ocean discharges.* If any of your solid and liquid wastes will be discharged overboard, or are planned discharges from manmade islands:

(1) A table showing the name, projected amount, and rate of discharge for each waste type; and

(2) A description of the discharge method (such as shunting through a downpipe, *etc.*) you will use.

(c) *National Pollutant Discharge Elimination System (NPDES) permit.* (1) A discussion of how you will comply with the provisions of the applicable general NPDES permit that covers your proposed exploration activities; or

(2) A copy of your application for an individual NPDES permit. Briefly describe the major discharges and methods you will use for compliance.

(d) *Modeling report.* The modeling report or the modeling results (if you modeled the discharges of your projected solid or liquid wastes when developing your EP), or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(e) *Projected cooling water intake.* A table for each cooling water intake structure likely to be used by your proposed exploration activities that includes a brief description of the cooling water intake structure, daily water intake rate, water intake through screen velocity, percentage of water intake used for cooling water, mitigation measures for reducing impingement and entrainment of aquatic organisms, and biofouling prevention measures.

§ 550.218 What air emissions information must accompany the EP?

The following air emissions information, as applicable, must accompany your EP:

(a) *Projected emissions.* Tables showing the projected emissions of criteria air pollutants, volatile organic compounds (VOC), and total suspended particulates (TSP) generated by your proposed exploration activities.

(1) For each source on or associated with the drilling unit (including well test flaring and well protection structure installation), you must list:

(i) The projected peak hourly emissions;

(ii) The total annual emissions in tons per year;

(iii) Emissions over the duration of the proposed exploration activities;

(iv) The frequency and duration of emissions; and

(v) The total of all emissions listed in paragraphs (a)(1)(i) through (iv) of this section.

(2) You must provide the basis for all calculations, including engine size and rating, and applicable operational information.

(3) You must base the projected emissions on the maximum rated capacity of the equipment on the proposed drilling unit under its physical and operational design.

(4) If the specific drilling unit has not yet been determined, you must use the maximum emission estimates for the type of drilling unit you will use.

(b) *Emission reduction measures*. A description of any proposed emission reduction measures, including the affected source(s), the emission reduction control technologies or procedures, the quantity of reductions to be achieved, and any monitoring system you propose to use to measure emissions.

(c) *Processes, equipment, fuels, and combustibles*. A description of processes, processing equipment, combustion equipment, fuels, and storage units. You must include the characteristics and the frequency, duration, and maximum burn rate of any well test fluids to be burned.

(d) *Distance to shore*. Identification of the distance of your drilling unit from the mean high water mark (mean higher high water mark on the Pacific coast) of the adjacent State.

(e) *Non-exempt drilling units*. A description of how you will comply with § 550.303 when the projected emissions reported under paragraph (a) of this section are greater than the respective emission exemption thresholds (EET) calculated using the formulas in § 550.303(d). When BOEM requires air quality dispersion modeling, you must use the guidelines in appendix W of 40 CFR part 51 for dispersion modeling with a model approved by the Director. You must also submit the best available meteorological information and data consistent with the model(s) used.

(f) *Modeling report*. A modeling report or the modeling results (if § 550.303 requires you to use an approved air quality model to model projected air emissions in developing your EP), or a reference to such a report or results if you have already submitted it to the Regional Supervisor.

[76 FR 64623, Oct. 18, 2011, as amended at 85 FR 34936, June 5, 2020]

§ 550.219 What oil and hazardous substance spills information must accompany the EP?

The following information regarding potential spills of oil (see definition under 30 CFR 254.6) and hazardous substances (see definition under 40 CFR part 116) as applicable, must accompany your EP:

(a) *Oil spill response planning*. The material required under paragraph (a)(1) or (a)(2) of this section:

(1) An Oil Spill Response Plan (OSRP) for the facilities you will use to conduct your exploration activities prepared according to the requirements of 30 CFR part 254, subpart B; or

(2) Reference to your approved regional OSRP (see 30 CFR 254.3) to include:

(i) A discussion of your regional OSRP;

(ii) The location of your primary oil spill equipment base and staging area;

(iii) The name(s) of your oil spill removal organization(s) for both equipment and personnel;

(iv) The calculated volume of your worst case discharge scenario (see 30 CFR 254.26(a)), and a comparison of the appropriate worst case discharge scenario in your approved regional OSRP with the worst case discharge scenario that could result from your proposed exploration activities; and

(v) A description of the worst case discharge scenario that could result from your proposed exploration activities (see 30 CFR 254.26(b), (c), (d), and (e)).

(b) *Modeling report*. If you model a potential oil or hazardous substance spill in developing your EP, a modeling report or the modeling results, or a reference to such report or results if you

have already submitted it to the Regional Supervisor.

§ 550.220 If I propose activities in the Alaska OCS Region, what planning information must accompany the EP?

If you propose exploration activities in the Alaska OCS Region, the following planning information must accompany your EP:

(a) *Emergency plans.* A description of your emergency plans to respond to a fire, explosion, personnel evacuation, or loss of well control, as well as a loss or disablement of a drilling unit, and loss of or damage to a support vessel, offshore vehicle, or aircraft.

(b) *Critical operations and curtailment procedures.* Critical operations and curtailment procedures for your exploration activities. The procedures must identify ice conditions, weather, and other constraints under which the exploration activities will either be curtailed or not proceed.

(c) If you propose exploration activities on the Arctic OCS, the following planning information must also accompany your EP:

(1) *Suitability for Arctic OCS conditions.* A description of how your exploratory drilling activities will be designed and conducted in a manner that accounts for Arctic OCS conditions and how such activities will be managed and overseen as an integrated endeavor.

(2) *Ice and weather management.* A description of your weather and ice forecasting and management plans for all phases of your exploratory drilling activities, including:

(i) A description of how you will respond to and manage ice hazards and weather events;

(ii) Your ice and weather alert procedures;

(iii) Your procedures and thresholds for activating your ice and weather management system(s); and

(iv) Confirmation that you will operate ice and weather management and alert systems continuously throughout the planned operations, including mobilization and demobilization operations to and from the Arctic OCS.

(3) *Source control and containment equipment capabilities.* A general description of how you will comply with § 250.471 of this title.

(4) *Deployment of a relief well rig.* A general description of how you will comply with § 250.472 of this title, including a description of the relief well rig, the anticipated staging area of the relief well rig, an estimate of the time it would take for the relief well rig to arrive at the site of a loss of well control, how you would drill a relief well if necessary, and the approximate timeframe to complete relief well operations.

(5) *Resource-sharing.* Any agreements you have with third parties for the sharing of assets or the provision of mutual aid in the event of an oil spill or other emergency.

(6) *Anticipated end of seasonal operations dates.* Your projected end of season dates, and the information used to identify those dates, for:

(i) The completion of on-site operations, which is contingent upon your capability in terms of equipment and procedures to manage and mitigate risks associated with Arctic OCS conditions; and

(ii) The termination of drilling operations consistent with the relief rig planning requirements under § 250.472 of this title and with your estimated timeframe under paragraph (c)(4) of this section for completion of relief well operations.

[76 FR 64623, Oct. 18, 2011, as amended at 81 FR 46565, July 15, 2016]

§ 550.221 What environmental monitoring information must accompany the EP?

The following environmental monitoring information, as applicable, must accompany your EP:

(a) *Monitoring systems.* A description of any existing and planned monitoring systems that are measuring, or will measure, environmental conditions or will provide project-specific data or information on the impacts of your exploration activities.

(b) *Incidental takes.* If there is reason to believe that protected species may be incidentally taken by planned exploration activities, you must describe how you will monitor for incidental take of:

(1) Threatened and endangered species listed under the ESA; and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take as may be necessary under the MMPA.

(c) *Flower Garden Banks National Marine Sanctuary (FGBNMS).* If you propose to conduct exploration activities within the protective zones of the FGBNMS, a description of your provisions for monitoring the impacts of an oil spill on the environmentally sensitive resources at the FGBNMS.

§ 550.222 What lease stipulations information must accompany the EP?

A description of the measures you took, or will take, to satisfy the conditions of lease stipulations related to your proposed exploration activities must accompany your EP.

§ 550.223 What mitigation measures information must accompany the EP?

(a) If you propose to use any measures beyond those required by the regulations in this part to minimize or mitigate environmental impacts from your proposed exploration activities, a description of the measures you will use must accompany your EP.

(b) If there is reason to believe that protected species may be incidentally taken by planned exploration activities, you must include mitigation measures designed to avoid or minimize the incidental take of:

(1) Threatened and endangered species listed under the ESA; and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take as may be necessary under the MMPA.

§ 550.224 What information on support vessels, offshore vehicles, and aircraft you will use must accompany the EP?

The following information on the support vessels, offshore vehicles, and aircraft you will use must accompany your EP:

(a) *General.* A description of the crew boats, supply boats, anchor handling vessels, tug boats, barges, ice management vessels, other vessels, offshore vehicles, and aircraft you will use to support your exploration activities. The description of vessels and offshore vehicles must estimate the storage capacity of their fuel tanks and the frequency of their visits to your drilling unit.

(b) *Air emissions.* A table showing the source, composition, frequency, and duration of the air emissions likely to be generated by the support vessels, offshore vehicles, and aircraft you will use that will operate within 25 miles of your drilling unit.

(c) *Drilling fluids and chemical products transportation.* A description of the transportation method and quantities of drilling fluids and chemical products (see § 550.213(b) and (c)) you will transport from the onshore support facilities you will use to your drilling unit.

(d) *Solid and liquid wastes transportation.* A description of the transportation method and a brief description of the composition, quantities, and destination(s) of solid and liquid wastes (see § 550.217(a)) you will transport from your drilling unit.

(e) *Vicinity map.* A map showing the location of your proposed exploration activities relative to the shoreline. The map must depict the primary route(s) the support vessels and aircraft will use when traveling between the onshore support facilities you will use and your drilling unit.

§ 550.225 What information on the onshore support facilities you will use must accompany the EP?

The following information on the onshore support facilities you will use must accompany your EP:

(a) *General.* A description of the onshore facilities you will use to provide supply and service support for your proposed exploration activities (e.g., service bases and mud company docks).

(1) Indicate whether the onshore support facilities are existing, to be constructed, or to be expanded.

(2) If the onshore support facilities are, or will be, located in areas not adjacent to the Western GOM, provide a timetable for acquiring lands (including rights-of-way and easements) and constructing or expanding the facilities. Describe any State or Federal permits or approvals (dredging, filling, *etc.*) that would be required for constructing or expanding them.

(b) *Air emissions.* A description of the source, composition, frequency, and duration of the air emissions (attributable to your proposed exploration activities) likely to be generated by the onshore support facilities you will use.

(c) *Unusual solid and liquid wastes.* A description of the quantity, composition, and method of disposal of any unusual solid and liquid wastes (attributable to your proposed exploration activities) likely to be generated by the onshore support facilities you will use. Unusual wastes are those wastes not specifically addressed in the relevant National Pollution Discharge Elimination System (NPDES) permit.

(d) *Waste disposal.* A description of the onshore facilities you will use to store and dispose of solid and liquid wastes generated by your proposed exploration activities (see § 550.217) and the types and quantities of such wastes.

§ 550.226 What Coastal Zone Management Act (CZMA) information must accompany the EP?

The following CZMA information must accompany your EP:

(a) *Consistency certification.* A copy of your consistency certification under section 307(c)(3)(B) of the CZMA (16 U.S.C. 1456(c)(3)(B)) and 15 CFR 930.76(d) stating that the proposed exploration activities described in detail in this EP comply with (name of State(s)) approved coastal management program(s) and will be conducted in a manner that is consistent with such program(s); and

(b) *Other information.* ''Information'' as required by 15 CFR 930.76(a) and 15 CFR 930.58(a)(2)) and ''Analysis'' as required by 15 CFR 930.58(a)(3).

§ 550.227 What environmental impact analysis (EIA) information must accompany the EP?

The following EIA information must accompany your EP:

(a) *General requirements.* Your EIA must:

(1) Assess the potential environmental impacts of your proposed exploration activities;

(2) Be project specific; and

(3) Be as detailed as necessary to assist the Regional Supervisor in complying with the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 *et seq.*) and other relevant Federal laws such as the ESA and the MMPA.

(b) *Resources, conditions, and activities.* Your EIA must describe those resources, conditions, and activities listed below that could be affected by your proposed exploration activities, or that could affect the construction and operation of facilities or structures, or the activities proposed in your EP.

(1) Meteorology, oceanography, geology, and shallow geological or man-made hazards;

(2) Air and water quality;

(3) Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, and plant life;

(4) Threatened or endangered species and their critical habitat as defined by the Endangered Species Act of 1973;

(5) Sensitive biological resources or habitats such as essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, and calving grounds;

(6) Archaeological resources;

(7) Socioeconomic resources including employment, existing offshore and coastal infrastructure (including major sources of supplies, services, energy, and water), land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including typical fishing seasons, location, and type), minority and lower income groups, and coastal zone management programs;

(8) Coastal and marine uses such as military activities, shipping, and mineral exploration or development; and

(9) Other resources, conditions, and activities identified by the Regional Supervisor.

(c) *Environmental impacts.* Your EIA must:

(1) Analyze the potential direct and indirect impacts (including those from accidents, cooling water intake structures, and those identified in relevant ESA biological opinions such as, but not limited to, those from noise, vessel collisions, and marine trash and debris)

that your proposed exploration activities will have on the identified resources, conditions, and activities;

(2) Analyze any potential cumulative impacts from other activities to those identified resources, conditions, and activities potentially impacted by your proposed exploration activities;

(3) Describe the type, severity, and duration of these potential impacts and their biological, physical, and other consequences and implications;

(4) Describe potential measures to minimize or mitigate these potential impacts; and

(5) Summarize the information you incorporate by reference.

(d) *Consultation*. Your EIA must include a list of agencies and persons with whom you consulted, or with whom you will be consulting, regarding potential impacts associated with your proposed exploration activities.

(e) *References cited*. Your EIA must include a list of the references that you cite in the EIA.

§ 550.228 What administrative information must accompany the EP?

The following administrative information must accompany your EP:

(a) *Exempted information description (public information copies only)*. A description of the general subject matter of the proprietary information that is included in the proprietary copies of your EP or its accompanying information.

(b) *Bibliography*. (1) If you reference a previously submitted EP, DPP, DOCD, study report, survey report, or other material in your EP or its accompanying information, a list of the referenced material; and

(2) The location(s) where the Regional Supervisor can inspect the cited referenced material if you have not submitted it.

REVIEW AND DECISION PROCESS FOR THE EP

§ 550.231 After receiving the EP, what will BOEM do?

(a) *Determine whether deemed submitted*. Within 15 working days after receiving your proposed EP and its accompanying information, the Regional Supervisor will review your submission and deem your EP submitted if:

(1) The submitted information, including the information that must accompany the EP (refer to the list in § 550.212), fulfills requirements and is sufficiently accurate;

(2) You have provided all needed additional information (see § 550.201(b)); and

(3) You have provided the required number of copies (see § 550.206(a)).

(b) *Identify problems and deficiencies*. If the Regional Supervisor determines that you have not met one or more of the conditions in paragraph (a) of this section, the Regional Supervisor will notify you of the problem or deficiency within 15 working days after the Regional Supervisor receives your EP and its accompanying information. The Regional Supervisor will not deem your EP submitted until you have corrected all problems or deficiencies identified in the notice.

(c) *Deemed submitted notification*. The Regional Supervisor will notify you when the EP is deemed submitted.

§ 550.232 What actions will BOEM take after the EP is deemed submitted?

(a) *State and CZMA consistency reviews*. Within 2 working days after deeming your EP submitted under § 550.231, the Regional Supervisor will use receipted mail or alternative method to send a public information copy of the EP and its accompanying information to the following:

(1) *The Governor of each affected State*. The Governor has 21 calendar days after receiving your deemed-submitted EP to submit comments. The Regional Supervisor will not consider comments received after the deadline.

(2) *The CZMA agency of each affected State*. The CZMA consistency review period under section 307(c)(3)(B)(ii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(ii)) and 15 CFR 930.78 begins when the State's CZMA agency receives a copy of your deemed-submitted EP, consistency certification, and required necessary data and information (see 15 CFR 930.77(a)(1)).

(b) *BOEM compliance review*. The Regional Supervisor will review the exploration activities described in your proposed EP to ensure that they conform to the performance standards in § 550.202.

(c) *BOEM environmental impact evaluation*. The Regional Supervisor will evaluate the environmental impacts of the activities described in your proposed EP and prepare environmental documentation under the National Environmental Policy Act (NEPA) (42 U.S.C. 4321 *et seq.*) and the implementing regulations (40 CFR parts 1500 through 1508).

(d) *Amendments*. During the review of your proposed EP, the Regional Supervisor may require you, or you may elect, to change your EP. If you elect to amend your EP, the Regional Supervisor may determine that your EP, as amended, is subject to the requirements of § 550.231.

§ 550.233 What decisions will BOEM make on the EP and within what timeframe?

(a) *Timeframe*. The Regional Supervisor will take one of the actions shown in the table in paragraph (b) of this section within 30 calendar days after the Regional Supervisor deems your EP submitted under § 550.231, or receives the last amendment to your proposed EP, whichever occurs later.

(b) *BOEM decision*. By the deadline in paragraph (a) of this section, the Regional Supervisor will take one of the following actions:

The regional supervisor will . . .	If . . .	And then . . .
(1) Approve your EP,	It complies with all applicable requirements,	The Regional Supervisor will notify you in writing of the decision and may require you to meet certain conditions, including those to provide monitoring information.
(2) Require you to modify your proposed EP,	The Regional Supervisor finds that it is inconsistent with the lease, the Act, the regulations prescribed under the Act, or other Federal laws,	The Regional Supervisor will notify you in writing of the decision and describe the modifications you must make to your proposed EP to ensure it complies with all applicable requirements.
(3) Disapprove your EP,	Your proposed activities would probably cause serious harm or damage to life (including fish or other aquatic life); property; any mineral (in areas leased or not leased); the National security or defense; or the marine, coastal, or human environment; and you cannot modify your proposed activities to avoid such condition(s),	(i) The Regional Supervisor will notify you in writing of the decision and describe the reason(s) for disapproving your EP. (ii) BOEM may cancel your lease and compensate you under 43 U.S.C. 1334(a)(2)(C) and the implementing regulations in §§ 550.182, 550.184, and 550.185 and 30 CFR 556.77.

§ 550.234 How do I submit a modified EP or resubmit a disapproved EP, and when will BOEM make a decision?

(a) *Modified EP*. If the Regional Supervisor requires you to modify your proposed EP under § 550.233(b)(2), you must submit the modification(s) to the Regional Supervisor in the same manner as for a new EP. You need submit only information related to the proposed modification(s).

(b) *Resubmitted EP*. If the Regional Supervisor disapproves your EP under § 550.233(b)(3), you may resubmit the disapproved EP if there is a change in the conditions that were the basis of its disapproval.

(c) *BOEM review and timeframe*. The Regional Supervisor will use the performance standards in § 550.202 to either approve, require you to further modify, or disapprove your modified or resubmitted EP. The Regional Supervisor will make a decision within 30 calendar days after the Regional Supervisor deems your modified or resubmitted EP to be submitted, or receives the last amendment to your modified or resubmitted EP, whichever occurs later.

§ 550.235 If a State objects to the EP's coastal zone consistency certification, what can I do?

If an affected State objects to the coastal zone consistency certification accompanying your proposed EP within the timeframe prescribed in § 550.233(a) or § 550.234(c), you may do one of the following:

(a) *Amend your EP*. Amend your EP to accommodate the State's objection and submit the amendment to the Regional Supervisor for approval. The

amendment needs to only address information related to the State's objection.

(b) *Appeal.* Appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930, subpart H. The Secretary of Commerce will either:

(1) Grant your appeal by finding, under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)), that each activity described in detail in your EP is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of National security; or

(2) Deny your appeal, in which case you may amend your EP as described in paragraph (a) of this section.

(c) *Withdraw your EP.* Withdraw your EP if you decide not to conduct your proposed exploration activities.

CONTENTS OF DEVELOPMENT AND PRODUCTION PLANS (DPP) AND DEVELOPMENT OPERATIONS COORDINATION DOCUMENTS (DOCD)

§ 550.241 What must the DPP or DOCD include?

Your DPP or DOCD must include the following:

(a) *Description, objectives, and schedule.* A description, discussion of the objectives, and tentative schedule (from start to completion) of the development and production activities you propose to undertake. Examples of development and production activities include:

(1) Development drilling;

(2) Well test flaring;

(3) Installation of production platforms, satellite structures, subsea wellheads and manifolds, and lease term pipelines (see definition at § 550.105); and

(4) Installation of production facilities and conduct of production operations.

(b) *Location.* The location and water depth of each of your proposed wells and production facilities. Include a map showing the surface and bottomhole location and water depth of each proposed well, the surface location of each production facility, and the locations of all associated drilling unit and construction barge anchors.

(c) *Drilling unit.* A description of the drilling unit and associated equipment you will use to conduct your proposed development drilling activities. Include a brief description of its important safety and pollution prevention features, and a table indicating the type and the estimated maximum quantity of fuels and oil that will be stored on the facility (see definition of ''facility (3)'' under § 550.105).

(d) *Production facilities.* A description of the production platforms, satellite structures, subsea wellheads and manifolds, lease term pipelines (see definition at § 550.105), production facilities, umbilicals, and other facilities you will use to conduct your proposed development and production activities. Include a brief description of their important safety and pollution prevention features, and a table indicating the type and the estimated maximum quantity of fuels and oil that will be stored on the facility (see definition of ''facility (3)'' under § 550.105).

(e) *Service fee.* You must include payment of the service fee listed in § 550.125.

§ 550.242 What information must accompany the DPP or DOCD?

The following information must accompany your DPP or DOCD.

(a) General information required by § 550.243;

(b) G&G information required by § 550.244;

(c) Hydrogen sulfide information required by § 550.245;

(d) Mineral resource conservation information required by § 550.246;

(e) Biological, physical, and socioeconomic information required by § 550.247;

(f) Solid and liquid wastes and discharges information and cooling water intake information required by § 550.248;

(g) Air emissions information required by § 550.249;

(h) Oil and hazardous substance spills information required by § 550.250;

(i) Alaska planning information required by § 550.251;

(j) Environmental monitoring information required by § 550.252;

(k) Lease stipulations information required by § 550.253;

(l) Mitigation measures information required by § 550.254;

(m) Decommissioning information required by § 550.255;

(n) Related facilities and operations information required by § 550.256;

(o) Support vessels and aircraft information required by § 550.257;

(p) Onshore support facilities information required by § 550.258;

(q) Sulphur operations information required by § 550.259;

(r) Coastal zone management information required by § 550.260;

(s) Environmental impact analysis information required by § 550.261; and

(t) Administrative information required by § 550.262.

§ 550.243 What general information must accompany the DPP or DOCD?

The following general information must accompany your DPP or DOCD:

(a) *Applications and permits.* A listing, including filing or approval status, of the Federal, State, and local application approvals or permits you must obtain to carry out your proposed development and production activities.

(b) *Drilling fluids.* A table showing the projected amount, discharge rate, and chemical constituents for each type (*i.e.*, water based, oil based, synthetic based) of drilling fluid you plan to use to drill your proposed development wells.

(c) *Production.* The following production information:

(1) Estimates of the average and peak rates of production for each type of production and the life of the reservoir(s) you intend to produce; and

(2) The chemical and physical characteristics of the produced oil (see definition under 30 CFR 254.6) that you will handle or store at the facilities you will use to conduct your proposed development and production activities.

(d) *Chemical products.* A table showing the name and brief description, quantities to be stored, storage method, and rates of usage of the chemical products you will use to conduct your proposed development and production activities. You need list only those chemical products you will store or use in quantities greater than the amounts defined as Reportable Quantities in 40 CFR part 302, or amounts specified by the Regional Supervisor.

(e) *New or unusual technology.* A description and discussion of any new or unusual technology (see definition under § 550.200) you will use to carry out your proposed development and production activities. In the public information copies of your DPP or DOCD, you may exclude any proprietary information from this description. In that case, include a brief discussion of the general subject matter of the omitted information. If you will not use any new or unusual technology to carry out your proposed development and production activities, include a statement so indicating.

(f) *Bonds, oil spill financial responsibility, and well control statements.* Statements attesting that:

(1) The activities and facilities proposed in your DPP or DOCD are or will be covered by an appropriate bond under 30 CFR part 556, subpart I;

(2) You have demonstrated or will demonstrate oil spill financial responsibility for facilities proposed in your DPP or DOCD, according to 30 CFR part 553; and

(3) You have or will have the financial capability to drill a relief well and conduct other emergency well control operations.

(g) *Suspensions of production or operations.* A brief discussion of any suspensions of production or suspensions of operations that you anticipate may be necessary in the course of conducting your activities under the DPP or DOCD.

(h) *Blowout scenario.* A scenario for a potential blowout of the proposed well in your DPP or DOCD that you expect will have the highest volume of liquid hydrocarbons. Include the estimated flow rate, total volume, and maximum duration of the potential blowout. Also, discuss the potential for the well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Estimate the time it would take to drill a relief well.

(i) *Contact.* The name, mailing address, (e-mail address if available), and telephone number of the person with whom the Regional Supervisor and the

affected State(s) can communicate about your DPP or DOCD.

§ 550.244 What geological and geophysical (G&G) information must accompany the DPP or DOCD?

The following G&G information must accompany your DPP or DOCD:

(a) *Geological description.* A geological description of the prospect(s).

(b) *Structure contour maps.* Current structure contour maps (depth-based, expressed in feet subsea) showing depths of expected productive formations and the locations of proposed wells.

(c) *Two dimensional (2–D) or three-dimensional (3–D) seismic lines.* Copies of migrated and annotated 2–D or 3–D seismic lines (with depth scale) intersecting at or near your proposed well locations. You are not required to conduct both 2–D and 3–D seismic surveys if you choose to conduct only one type of survey. If you have conducted both types of surveys, the Regional Supervisor may instruct you to submit the results of both surveys. You must interpret and display this information. Provide this information as an enclosure to only one proprietary copy of your DPP or DOCD.

(d) *Geological cross-sections.* Interpreted geological cross-sections showing the depths of expected productive formations.

(e) *Shallow hazards report.* A shallow hazards report based on information obtained from a high-resolution geophysical survey, or a reference to such report if you have already submitted it to the Regional Supervisor.

(f) *Shallow hazards assessment.* For each proposed well, an assessment of any seafloor and subsurface geologic and manmade features and conditions that may adversely affect your proposed drilling operations.

(g) *High resolution seismic lines.* A copy of the high-resolution survey line closest to each of your proposed well locations. Because of its volume, provide this information as an enclosure to only one proprietary copy of your DPP or DOCD. You are not required to provide this information if the surface location of your proposed well has been approved in a previously submitted EP, DPP, or DOCD.

(h) *Stratigraphic column.* A generalized biostratigraphic/lithostratigraphic column from the surface to the total depth of each proposed well.

(i) *Time-versus-depth chart.* A seismic travel time-versus-depth chart based on the appropriate velocity analysis in the area of interpretation and specifying the geodetic datum.

(j) *Geochemical information.* A copy of any geochemical reports you used or generated.

(k) *Future G&G activities.* A brief description of the G&G explorations and development G&G activities that you may conduct for lease or unit purposes after your DPP or DOCD is approved.

§ 550.245 What hydrogen sulfide (H_2S) information must accompany the DPP or DOCD?

The following H_2S information, as applicable, must accompany your DPP or DOCD:

(a) *Concentration.* The estimated concentration of any H_2S you might encounter or handle while you conduct your proposed development and production activities.

(b) *Classification.* Under 30 CFR 250.490(c), a request that the Regional Supervisor classify the area of your proposed development and production activities as either H_2S absent, H_2S present, or H_2S unknown. Provide sufficient information to justify your request.

(c) *H_2S Contingency Plan.* If you request that the Regional Supervisor classify the area of your proposed development and production activities as either H_2S present or H_2S unknown, an H_2S Contingency Plan prepared under 30 CFR 250.490(f), or a reference to an approved or submitted H_2S Contingency Plan that covers the proposed development and production activities.

(d) *Modeling report.* (1) If you have determined or estimated that the concentration of any H_2S you may encounter or handle while you conduct your development and production activities will be greater than 500 parts per million (ppm), you must:

(i) Model a potential worst case H_2S release from the facilities you will use to conduct your proposed development and production activities; and

(ii) Include a modeling report or modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(2) The analysis in the modeling report must be specific to the particular site of your development and production activities, and must consider any nearby human-occupied OCS facilities, shipping lanes, fishery areas, and other points where humans may be subject to potential exposure from an H_2S release from your proposed activities.

(3) If any H_2S emissions are projected to affect an onshore location in concentrations greater than 10 ppm, the modeling analysis must be consistent with the EPA's risk management plan methodologies outlined in 40 CFR part 68.

§ 550.246 What mineral resource conservation information must accompany the DPP or DOCD?

The following mineral resource conservation information, as applicable, must accompany your DPP or DOCD:

(a) *Technology and reservoir engineering practices and procedures.* A description of the technology and reservoir engineering practices and procedures you will use to increase the ultimate recovery of oil and gas (e.g., secondary, tertiary, or other enhanced recovery practices). If you will not use enhanced recovery practices initially, provide an explanation of the methods you considered and the reasons why you are not using them.

(b) *Technology and recovery practices and procedures.* A description of the technology and recovery practices and procedures you will use to ensure optimum recovery of oil and gas or sulphur.

(c) *Reservoir development.* A discussion of exploratory well results, other reservoir data, proposed well spacing, completion methods, and other relevant well plan information.

§ 550.247 What biological, physical, and socioeconomic information must accompany the DPP or DOCD?

If you obtain the following information in developing your DPP or DOCD, or if the Regional Supervisor requires you to obtain it, you must include a report, or the information obtained, or a reference to such a report or information if you have already submitted it to the Regional Supervisor, as accompanying information:

(a) *Biological environment reports.* Site-specific information on chemosynthetic communities, federally listed threatened or endangered species, marine mammals protected under the MMPA, sensitive underwater features, marine sanctuaries, critical habitat designated under the ESA, or other areas of biological concern.

(b) *Physical environment reports.* Site-specific meteorological, physical oceanographic, geotechnical reports, or archaeological reports (if required under § 550.194).

(c) *Socioeconomic study reports.* Socioeconomic information related to your proposed development and production activities.

§ 550.248 What solid and liquid wastes and discharges information and cooling water intake information must accompany the DPP or DOCD?

The following solid and liquid wastes and discharges information and cooling water intake information must accompany your DPP or DOCD:

(a) *Projected wastes.* A table providing the name, brief description, projected quantity, and composition of solid and liquid wastes (such as spent drilling fluids, drill cuttings, trash, sanitary and domestic wastes, produced waters, and chemical product wastes) likely to be generated by your proposed development and production activities. Describe:

(1) The methods you used for determining this information; and

(2) Your plans for treating, storing, and downhole disposal of these wastes at your facility location(s).

(b) *Projected ocean discharges.* If any of your solid and liquid wastes will be discharged overboard or are planned discharges from manmade islands:

(1) A table showing the name, projected amount, and rate of discharge for each waste type; and

(2) A description of the discharge method (such as shunting through a downpipe, adding to a produced water stream, *etc.*) you will use.

(c) *National Pollutant Discharge Elimination System (NPDES) permit.* (1) A discussion of how you will comply with the provisions of the applicable general NPDES permit that covers your proposed development and production activities; or

(2) A copy of your application for an individual NPDES permit. Briefly describe the major discharges and methods you will use for compliance.

(d) *Modeling report.* A modeling report or the modeling results (if you modeled the discharges of your projected solid or liquid wastes in developing your DPP or DOCD), or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(e) *Projected cooling water intake.* A table for each cooling water intake structure likely to be used by your proposed development and production activities that includes a brief description of the cooling water intake structure, daily water intake rate, water intake through-screen velocity, percentage of water intake used for cooling water, mitigation measures for reducing impingement and entrainment of aquatic organisms, and biofouling prevention measures.

§ 550.249 What air emissions information must accompany the DPP or DOCD?

The following air emissions information, as applicable, must accompany your DPP or DOCD:

(a) *Projected emissions.* Tables showing the projected emissions of criteria air pollutants, volatile organic compounds (VOC), and total suspended particulates (TSP) generated by your proposed development and production activities.

(1) For each source on or associated with the facility you will use to conduct your proposed development and production activities, you must list:

(i) The projected peak hourly emissions;

(ii) The total annual emissions in tons per year;

(iii) Emissions over the duration of the proposed development and production activities;

(iv) The frequency and duration of emissions; and

(v) The total of all emissions listed in paragraph (a)(1)(i) through (iv) of this section.

(2) If your proposed production and development activities would result in an increase in the emissions of a criteria air pollutant, VOC, or TSP from your facility to an amount greater than the amount specified in your previously approved DPP or DOCD, you must show the revised emission rates for each source as well as the incremental change for each source.

(3) You must provide the basis for all calculations, including engine size and rating, and applicable operational information.

(4) You must base the projected emissions on the maximum rated capacity of the equipment and the maximum throughput of the facility you will use to conduct your proposed development and production activities under its physical and operational design.

(5) If the specific drilling unit has not yet been determined, you must use the maximum emission estimates for the type of drilling unit you will use.

(b) *Emission reduction measures.* A description of any proposed emission reduction measures, including the affected source(s), the emission reduction control technologies or procedures, the quantity of reductions to be achieved, and any monitoring system you propose to use to measure emissions.

(c) *Processes, equipment, fuels, and combustibles.* A description of processes, processing equipment, combustion equipment, fuels, and storage units. You must include the frequency, duration, and maximum burn rate of any flaring activity.

(d) *Distance to shore.* Identification of the distance of the site of your proposed development and production activities from the mean high water mark (mean higher high water mark on the Pacific coast) of the adjacent State.

(e) *Non-exempt facilities.* A description of how you will comply with § 550.303 when the projected emissions reported under paragraph (a) of this section are greater than the respective emission exemption thresholds (EET) calculated using the formulas in § 550.303(d). When BOEM requires air quality dispersion

modeling, you must use the guidelines in appendix W of 40 CFR part 51 for dispersion modeling with a model approved by the Director. You must also submit the best available meteorological information and data consistent with the model(s) used.

(f) *Modeling report.* A modeling report or the modeling results (if § 550.303 requires you to use an approved air quality model to model projected air emissions in developing your DPP or DOCD), or a reference to such report or results if you have already submitted it to the Regional Supervisor.

[76 FR 64623, Oct. 18, 2011, as amended at 85 FR 34936, June 5, 2020]

§ 550.250 What oil and hazardous substance spills information must accompany the DPP or DOCD?

The following information regarding potential spills of oil (see definition under 30 CFR 254.6) and hazardous substances (see definition under 40 CFR part 116), as applicable, must accompany your DPP or DOCD:

(a) *Oil spill response planning.* The material required under paragraph (a)(1) or (a)(2) of this section:

(1) An Oil Spill Response Plan (OSRP) for the facilities you will use to conduct your proposed development and production activities prepared according to the requirements of 30 CFR part 254, subpart B; or

(2) Reference to your approved regional OSRP (see 30 CFR 254.3) to include:

(i) A discussion of your regional OSRP;

(ii) The location of your primary oil spill equipment base and staging area;

(iii) The name(s) of your oil spill removal organization(s) for both equipment and personnel;

(iv) The calculated volume of your worst case discharge scenario (see 30 CFR 254.26(a)), and a comparison of the appropriate worst case discharge scenario in your approved regional OSRP with the worst case discharge scenario that could result from your proposed development and production activities; and

(v) A description of the worst case oil spill scenario that could result from your proposed development and production activities (see 30 CFR 254.26(b), (c), (d), and (e)).

(b) *Modeling report.* If you model a potential oil or hazardous substance spill in developing your DPP or DOCD, a modeling report or the modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

§ 550.251 If I propose activities in the Alaska OCS Region, what planning information must accompany the DPP?

If you propose development and production activities in the Alaska OCS Region, the following planning information must accompany your DPP:

(a) *Emergency plans.* A description of your emergency plans to respond to a blowout, loss or disablement of a drilling unit, and loss of or damage to support craft; and

(b) *Critical operations and curtailment procedures.* Critical operations and curtailment procedures for your development and production activities. The procedures must identify ice conditions, weather, and other constraints under which the development and production activities will either be curtailed or not proceed.

§ 550.252 What environmental monitoring information must accompany the DPP or DOCD?

The following environmental monitoring information, as applicable, must accompany your DPP or DOCD:

(a) *Monitoring systems.* A description of any existing and planned monitoring systems that are measuring, or will measure, environmental conditions or will provide project-specific data or information on the impacts of your development and production activities.

(b) *Incidental takes.* If there is reason to believe that protected species may be incidentally taken by planned development and production activities, you must describe how you will monitor for incidental take of:

(1) Threatened and endangered species listed under the ESA; and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take of marine mammals as may be necessary under the MMPA.

(c) *Flower Garden Banks National Marine Sanctuary (FGBNMS).* If you propose to conduct development and production activities within the protective zones of the FGBNMS, a description of your provisions for monitoring the impacts of oil spill on the environmentally sensitive resources of the FGBNMS.

§ 550.253 What lease stipulations information must accompany the DPP or DOCD?

A description of the measures you took, or will take, to satisfy the conditions of lease stipulations related to your proposed development and production activities must accompany your DPP or DOCD.

§ 550.254 What mitigation measures information must accompany the DPP or DOCD?

(a) If you propose to use any measures beyond those required by the regulations in this part to minimize or mitigate environmental impacts from your proposed development and production activities, a description of the measures you will use must accompany your DPP or DOCD.

(b) If there is reason to believe that protected species may be incidentally taken by planned development and production activities, you must include mitigation measures designed to avoid or minimize that incidental take of:

(1) Threatened and endangered species listed under the ESA; and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take as may be necessary under the MMPA.

§ 550.255 What decommissioning information must accompany the DPP or DOCD?

A brief description of how you intend to decommission your wells, platforms, pipelines, and other facilities, and clear your site(s) must accompany your DPP or DOCD.

§ 550.256 What related facilities and operations information must accompany the DPP or DOCD?

The following information regarding facilities and operations directly related to your proposed development and production activities must accompany your DPP or DOCD.

(a) *OCS facilities and operations.* A description and location of any of the following that directly relate to your proposed development and production activities:

(1) Drilling units;

(2) Production platforms;

(3) Right-of-way pipelines (including those that transport chemical products and produced water); and

(4) Other facilities and operations located on the OCS (regardless of ownership).

(b) *Transportation system.* A discussion of the transportation system that you will use to transport your production to shore, including:

(1) Routes of any new pipelines;

(2) Information concerning barges and shuttle tankers, including the storage capacity of the transport vessel(s), and the number of transfers that will take place per year;

(3) Information concerning any intermediate storage or processing facilities;

(4) An estimate of the quantities of oil, gas, or sulphur to be transported from your production facilities; and

(5) A description and location of the primary onshore terminal.

§ 550.257 What information on the support vessels, offshore vehicles, and aircraft you will use must accompany the DPP or DOCD?

The following information on the support vessels, offshore vehicles, and aircraft you will use must accompany your DPP or DOCD:

(a) *General.* A description of the crew boats, supply boats, anchor handling vessels, tug boats, barges, ice management vessels, other vessels, offshore vehicles, and aircraft you will use to support your development and production activities. The description of vessels and offshore vehicles must estimate the storage capacity of their fuel tanks and the frequency of their visits to the facilities you will use to conduct your proposed development and production activities.

(b) *Air emissions.* A table showing the source, composition, frequency, and duration of the air emissions likely to be generated by the support vessels, offshore vehicles, and aircraft you will

use that will operate within 25 miles of the facilities you will use to conduct your proposed development and production activities.

(c) *Drilling fluids and chemical products transportation.* A description of the transportation method and quantities of drilling fluids and chemical products (see § 550.243(b) and (d)) you will transport from the onshore support facilities you will use to the facilities you will use to conduct your proposed development and production activities.

(d) *Solid and liquid wastes transportation.* A description of the transportation method and a brief description of the composition, quantities, and destination(s) of solid and liquid wastes (see § 550.248(a)) you will transport from the facilities you will use to conduct your proposed development and production activities.

(e) *Vicinity map.* A map showing the location of your proposed development and production activities relative to the shoreline. The map must depict the primary route(s) the support vessels and aircraft will use when traveling between the onshore support facilities you will use and the facilities you will use to conduct your proposed development and production activities.

§ 550.258 What information on the onshore support facilities you will use must accompany the DPP or DOCD?

The following information on the onshore support facilities you will use must accompany your DPP or DOCD:

(a) *General.* A description of the onshore facilities you will use to provide supply and service support for your proposed development and production activities (e.g., service bases and mud company docks).

(1) Indicate whether the onshore support facilities are existing, to be constructed, or to be expanded; and

(2) For DPPs only, provide a timetable for acquiring lands (including rights-of-way and easements) and constructing or expanding any of the onshore support facilities.

(b) *Air emissions.* A description of the source, composition, frequency, and duration of the air emissions (attributable to your proposed development and production activities) likely to be generated by the onshore support facilities you will use.

(c) *Unusual solid and liquid wastes.* A description of the quantity, composition, and method of disposal of any unusual solid and liquid wastes (attributable to your proposed development and production activities) likely to be generated by the onshore support facilities you will use. Unusual wastes are those wastes not specifically addressed in the relevant National Pollution Discharge Elimination System (NPDES) permit.

(d) *Waste disposal.* A description of the onshore facilities you will use to store and dispose of solid and liquid wastes generated by your proposed development and production activities (see § 550.248(a)) and the types and quantities of such wastes.

§ 550.259 What sulphur operations information must accompany the DPP or DOCD?

If you are proposing to conduct sulphur development and production activities, the following information must accompany your DPP or DOCD:

(a) *Bleedwater.* A discussion of the bleedwater that will be generated by your proposed sulphur activities, including the measures you will take to mitigate the potential toxic or thermal impacts on the environment caused by the discharge of bleedwater.

(b) *Subsidence.* An estimate of the degree of subsidence expected at various stages of your sulphur development and production activities, and a description of the measures you will take to mitigate the effects of subsidence on existing or potential oil and gas production, production platforms, and production facilities, and to protect the environment.

§ 550.260 What Coastal Zone Management Act (CZMA) information must accompany the DPP or DOCD?

The following CZMA information must accompany your DPP or DOCD:

(a) *Consistency certification.* A copy of your consistency certification under section 307(c)(3)(B) of the CZMA (16 U.S.C. 1456(c)(3)(B)) and 15 CFR 930.76(c) stating that the proposed development and production activities described in detail in this DPP or DOCD comply

with (name of State(s)) approved coastal management program(s) and will be conducted in a manner that is consistent with such program(s); and

(b) *Other information.* ''Information'' as required by 15 CFR 930.76(a) and 15 CFR 930.58(a)(2)) and ''Analysis'' as required by 15 CFR 930.58(a)(3).

§ 550.261 What environmental impact analysis (EIA) information must accompany the DPP or DOCD?

The following EIA information must accompany your DPP or DOCD:

(a) *General requirements.* Your EIA must:

(1) Assess the potential environmental impacts of your proposed development and production activities;

(2) Be project specific; and

(3) Be as detailed as necessary to assist the Regional Supervisor in complying with the NEPA of 1969 (42 U.S.C. 4321 *et seq.*) and other relevant Federal laws such as the ESA and the MMPA.

(b) *Resources, conditions, and activities.* Your EIA must describe those resources, conditions, and activities listed below that could be affected by your proposed development and production activities, or that could affect the construction and operation of facilities or structures or the activities proposed in your DPP or DOCD.

(1) Meteorology, oceanography, geology, and shallow geological or manmade hazards;

(2) Air and water quality;

(3) Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, and plant life;

(4) Threatened or endangered species and their critical habitat;

(5) Sensitive biological resources or habitats such as essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, and calving grounds;

(6) Archaeological resources;

(7) Socioeconomic resources (including the approximate number, timing, and duration of employment of persons engaged in onshore support and construction activities), population (including the approximate number of people and families added to local onshore areas), existing offshore and onshore infrastructure (including major sources of supplies, services, energy, and water), types of contractors or vendors that may place a demand on local goods and services, land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including seasons, location, and type), minority and lower income groups, and CZMA programs;

(8) Coastal and marine uses such as military activities, shipping, and mineral exploration or development; and

(9) Other resources, conditions, and activities identified by the Regional Supervisor.

(c) *Environmental impacts.* Your EIA must:

(1) Analyze the potential direct and indirect impacts (including those from accidents, cooling water intake structures, and those identified in relevant ESA biological opinions such as, but not limited to, those from noise, vessel collisions, and marine trash and debris) that your proposed development and production activities will have on the identified resources, conditions, and activities;

(2) Describe the type, severity, and duration of these potential impacts and their biological, physical, and other consequences and implications;

(3) Describe potential measures to minimize or mitigate these potential impacts;

(4) Describe any alternatives to your proposed development and production activities that you considered while developing your DPP or DOCD, and compare the potential environmental impacts; and

(5) Summarize the information you incorporate by reference.

(d) *Consultation.* Your EIA must include a list of agencies and persons with whom you consulted, or with whom you will be consulting, regarding potential impacts associated with your proposed development and production activities.

(e) *References cited.* Your EIA must include a list of the references that you cite in the EIA.

§ 550.262 What administrative information must accompany the DPP or DOCD?

The following administrative information must accompany your DPP or DOCD:

(a) *Exempted information description (public information copies only).* A description of the general subject matter of the proprietary information that is included in the proprietary copies of your DPP or DOCD or its accompanying information.

(b) *Bibliography.* (1) If you reference a previously submitted EP, DPP, DOCD, study report, survey report, or other material in your DPP or DOCD or its accompanying information, a list of the referenced material; and

(2) The location(s) where the Regional Supervisor can inspect the cited referenced material if you have not submitted it.

REVIEW AND DECISION PROCESS FOR THE DPP OR DOCD

§ 550.266 After receiving the DPP or DOCD, what will BOEM do?

(a) *Determine whether deemed submitted.* Within 25 working days after receiving your proposed DPP or DOCD and its accompanying information, the Regional Supervisor will deem your DPP or DOCD submitted if:

(1) The submitted information, including the information that must accompany the DPP or DOCD (refer to the list in § 550.242), fulfills requirements and is sufficiently accurate;

(2) You have provided all needed additional information (see § 550.201(b)); and

(3) You have provided the required number of copies (see § 550.206(a)).

(b) *Identify problems and deficiencies.* If the Regional Supervisor determines that you have not met one or more of the conditions in paragraph (a) of this section, the Regional Supervisor will notify you of the problem or deficiency within 25 working days after the Regional Supervisor receives your DPP or DOCD and its accompanying information. The Regional Supervisor will not deem your DPP or DOCD submitted until you have corrected all problems or deficiencies identified in the notice.

(c) *Deemed submitted notification.* The Regional Supervisor will notify you when your DPP or DOCD is deemed submitted.

§ 550.267 What actions will BOEM take after the DPP or DOCD is deemed submitted?

(a) *State, local government, CZMA consistency, and other reviews.* Within 2 working days after the Regional Supervisor deems your DPP or DOCD submitted under § 550.266, the Regional Supervisor will use receipted mail or alternative method to send a public information copy of the DPP or DOCD and its accompanying information to the following:

(1) *The Governor of each affected State.* The Governor has 60 calendar days after receiving your deemed-submitted DPP or DOCD to submit comments and recommendations. The Regional Supervisor will not consider comments and recommendations received after the deadline.

(2) *The executive of any affected local government who requests a copy.* The executive of any affected local government has 60 calendar days after receipt of your deemed-submitted DPP or DOCD to submit comments and recommendations. The Regional Supervisor will not consider comments and recommendations received after the deadline. The executive of any affected local government must forward all comments and recommendations to the respective Governor before submitting them to the Regional Supervisor.

(3) *The CZMA agency of each affected State.* The CZMA consistency review period under section 307(c)(3)(B)(ii) of the CZMA (16 U.S.C.1456(c)(3)(B)(ii)) and 15 CFR 930.78 begins when the States CZMA agency receives a copy of your deemed-submitted DPP or DOCD, consistency certification, and required necessary data/information (see 15 CFR 930.77(a)(1)).

(b) *General public.* Within 2 working days after the Regional Supervisor deems your DPP or DOCD submitted under § 550.266, the Regional Supervisor will make a public information copy of

the DPP or DOCD and its accompanying information available for review to any appropriate interstate regional entity and the public at the appropriate BOEM Regional Public Information Office. Any interested Federal agency or person may submit comments and recommendations to the Regional Supervisor. Comments and recommendations must be received by the Regional Supervisor within 60 calendar days after the DPP or DOCD including its accompanying information is made available.

(c) *BOEM compliance review*. The Regional Supervisor will review the development and production activities in your proposed DPP or DOCD to ensure that they conform to the performance standards in § 550.202.

(d) *Amendments*. During the review of your proposed DPP or DOCD, the Regional Supervisor may require you, or you may elect, to change your DPP or DOCD. If you elect to amend your DPP or DOCD, the Regional Supervisor may determine that your DPP or DOCD, as amended, is subject to the requirements of § 550.266.

§ 550.268 How does BOEM respond to recommendations?

(a) *Governor*. The Regional Supervisor will accept those recommendations from the Governor that provide a reasonable balance between the National interest and the well-being of the citizens of each affected State. The Regional Supervisor will explain in writing to the Governor the reasons for rejecting any of his or her recommendations.

(b) *Local governments and the public*. The Regional Supervisor may accept recommendations from the executive of any affected local government or the public.

(c) *Availability*. The Regional Supervisor will make all comments and recommendations available to the public upon request.

§ 550.269 How will BOEM evaluate the environmental impacts of the DPP or DOCD?

The Regional Supervisor will evaluate the environmental impacts of the activities described in your proposed DPP or DOCD and prepare environmental documentation under the National Environmental Policy Act (NEPA) (42 U.S.C.4321 *et seq.*) and the implementing regulations (40 CFR parts 1500 through 1508).

(a) *Environmental impact statement (EIS) declaration*. At least once in each OCS planning area (other than the Western and Central GOM Planning Areas), the Director will declare that the approval of a proposed DPP is a major Federal action, and BOEM will prepare an EIS.

(b) *Leases or units in the vicinity*. Before or immediately after the Director determines that preparation of an EIS is required, the Regional Supervisor may require lessees and operators of leases or units in the vicinity of the proposed development and production activities for which DPPs have not been approved to submit information about preliminary plans for their leases or units.

(c) *Draft EIS*. The Regional Supervisor will send copies of the draft EIS to the Governor of each affected State and to the executive of each affected local government who requests a copy. Additionally, when BOEM prepares a DPP EIS, and the Federally-approved CZMA program for an affected State requires a DPP NEPA document for use in determining consistency, the Regional Supervisor will forward a copy of the draft EIS to the State's CZMA agency. The Regional Supervisor will also make copies of the draft EIS available to any appropriate Federal agency, interstate regional entity, and the public.

§ 550.270 What decisions will BOEM make on the DPP or DOCD and within what timeframe?

(a) *Timeframe*. The Regional Supervisor will act on your deemed-submitted DPP or DOCD as follows:

(1) The Regional Supervisor will make a decision within 60 calendar days after the latest of the day that:

(i) The comment period provided in § 550.267(a)(1), (a)(2), and (b) closes;

(ii) The final EIS for a DPP is released or adopted; or

(iii) The last amendment to your proposed DOCD is received by the Regional Supervisor.

(2) Notwithstanding paragraph (a)(1) of this section, BOEM will not approve your DPP or DOCD until either:

(i) All affected States with approved CZMA programs concur, or have been conclusively presumed to concur, with your DPP or DOCD consistency certification under section 307(c)(3)(B)(i) and (ii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(i) and (ii)); or

(ii) The Secretary of Commerce has made a finding authorized by section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)) that each activity described in the DPP or DOCD is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of National security.

(b) *BOEM decision*. By the deadline in paragraph (a) of this section, the Regional Supervisor will take one of the following actions:

The regional supervisor will . . .	If . . .	And then . . .
(1) Approve your DPP or DOCD,	It complies with all applicable requirements,	The Regional Supervisor will notify you in writing of the decision and may require you to meet certain conditions, including those to provide monitoring information.
(2) Require you to modify your proposed DPP or DOCD,	It fails to make adequate provisions for safety, environmental protection, or conservation of natural resources or otherwise does not comply with the lease, the Act, the regulations prescribed under the Act, or other Federal laws,	The Regional Supervisor will notify you in writing of the decision and describe the modifications you must make to your proposed DPP or DOCD to ensure it complies with all applicable requirements.
(3) Disapprove your DPP or DOCD,	Any of the reasons in § 550.271 apply,	(i) The Regional Supervisor will notify you in writing of the decision and describe the reason(s) for disapproving your DPP or DOCD; and (ii) BOEM may cancel your lease and compensate you under 43 U.S.C. 1351(h)(2)(C) and the implementing regulations in §§ 550.183 through 550.185 and 30 CFR 556.77.

§ 550.271 For what reasons will BOEM disapprove the DPP or DOCD?

The Regional Supervisor will disapprove your proposed DPP or DOCD if one of the four reasons in this section applies:

(a) *Non-compliance*. The Regional Supervisor determines that you have failed to demonstrate that you can comply with the requirements of the Outer Continental Shelf Lands Act, as amended (Act), implementing regulations, or other applicable Federal laws.

(b) *No consistency concurrence*. (1) An affected State has not yet issued a final decision on your coastal zone consistency certification (see 15 CFR 930.78(a)); or

(2) An affected State objects to your coastal zone consistency certification, and the Secretary of Commerce, under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)), has not found that each activity described in the DPP or DOCD is consistent with the objectives of the CZMA or is otherwise necessary in the interest of National security.

(3) If the Regional Supervisor disapproved your DPP or DOCD for the sole reason that an affected State either has not yet issued a final decision on, or has objected to, your coastal zone consistency certification (see paragraphs (b)(1) and (2) in this section), the Regional Supervisor will approve your DPP or DOCD upon receipt of concurrence by the affected State, at the time concurrence of the affected State is conclusively presumed, or when the Secretary of Commerce makes a finding authorized by section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)) that each activity described in your DPP or DOCD is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of National security. In that event, you do not need to resubmit your DPP or DOCD for approval under § 550.273(b).

(c) *National security or defense conflicts*. Your proposed activities would threaten National security or defense.

(d) *Exceptional circumstances*. The Regional Supervisor determines because

of exceptional geological conditions, exceptional resource values in the marine or coastal environment, or other exceptional circumstances that all of the following apply:

(1) Implementing your DPP or DOCD would 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 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 disapproving your DPP or DOCD outweigh the advantages of development and production.

§ 550.272 If a State objects to the DPP's or DOCD's coastal zone consistency certification, what can I do?

If an affected State objects to the coastal zone consistency certification accompanying your proposed or disapproved DPP or DOCD, you may do one of the following:

(a) *Amend or resubmit your DPP or DOCD.* Amend or resubmit your DPP or DOCD to accommodate the State's objection and submit the amendment or resubmittal to the Regional Supervisor for approval. The amendment or resubmittal needs to only address information related to the State's objections.

(b) *Appeal.* Appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930, subpart H. The Secretary of Commerce will either:

(1) Grant your appeal by finding under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C.1456(c)(3)(B)(iii)) that each activity described in detail in your DPP or DOCD is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of National security; or

(2) Deny your appeal, in which case you may amend or resubmit your DPP or DOCD, as described in paragraph (a) of this section.

(c) *Withdraw your DPP or DOCD.* Withdraw your DPP or DOCD if you decide not to conduct your proposed development and production activities.

§ 550.273 How do I submit a modified DPP or DOCD or resubmit a disapproved DPP or DOCD?

(a) *Modified DPP or DOCD.* If the Regional Supervisor requires you to modify your proposed DPP or DOCD under § 550.270(b)(2), you must submit the modification(s) to the Regional Supervisor in the same manner as for a new DPP or DOCD. You need submit only information related to the proposed modification(s).

(b) *Resubmitted DPP or DOCD.* If the Regional Supervisor disapproves your DPP or DOCD under § 550.270(b)(3), and except as provided in § 550.271(b)(3), you may resubmit the disapproved DPP or DOCD if there is a change in the conditions that were the basis of its disapproval.

(c) *BOEM review and timeframe.* The Regional Supervisor will use the performance standards in § 550.202 to either approve, require you to further modify, or disapprove your modified or resubmitted DPP or DOCD. The Regional Supervisor will make a decision within 60 calendar days after the Regional Supervisor deems your modified or resubmitted DPP or DOCD to be submitted, or receives the last amendment to your modified or resubmitted DPP or DOCD, whichever occurs later.

POST-APPROVAL REQUIREMENTS FOR THE EP, DPP, AND DOCD

§ 550.280 How must I conduct activities under the approved EP, DPP, or DOCD?

(a) *Compliance.* You must conduct all of your lease and unit activities according to your approved EP, DPP, or DOCD and any approval conditions. If you fail to comply with your approved EP, DPP, or DOCD:

(1) You may be subject to BOEM enforcement action, including civil penalties; and

(2) The lease(s) involved in your EP, DPP, or DOCD may be forfeited or cancelled under 43 U.S.C. 1334(c) or (d). If this happens, you will not be entitled to compensation under § 550.185(b) and 30 CFR 556.77.

(b) *Emergencies.* Nothing in this subpart or in your approved EP, DPP, or DOCD relieves you of, or limits your responsibility to take appropriate

measures to meet emergency situations. In an emergency situation, the Regional Supervisor may approve or require departures from your approved EP, DPP, or DOCD.

§ 550.281 What must I do to conduct activities under the approved EP, DPP, or DOCD?

(a) *Approvals and permits.* Before you conduct activities under your approved EP, DPP, or DOCD you must obtain the following approvals and or permits, as applicable, from the District Manager or BSEE Regional Supervisor:

(1) Approval of applications for permits to drill (APDs) (see 30 CFR 250.410);

(2) Approval of production safety systems (see 30 CFR 250.800);

(3) Approval of new platforms and other structures (or major modifications to platforms and other structures) (see 30 CFR 250.905);

(4) Approval of applications to install lease term pipelines (see 30 CFR 250.1007); and

(5) Other permits, as required by applicable law.

(b) *Conformance.* The activities proposed in these applications and permits must conform to the activities described in detail in your approved EP, DPP, or DOCD.

(c) *Separate State CZMA consistency review.* APDs, and other applications for licenses, approvals, or permits to conduct activities under your approved EP, DPP, or DOCD including those identified in paragraph (a) of this section, are not subject to separate State CZMA consistency review.

(d) *Approval restrictions for permits for activities conducted under EPs.* The Regional Supervisor will not approve any APDs or other applications for licenses, approvals, or permits under your approved EP until either:

(1) All affected States with approved coastal zone management programs concur, or are conclusively presumed to concur, with the coastal zone consistency certification accompanying your EP under section 307(c)(3)(B)(i) and (ii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(i) and (ii)); or

(2) The Secretary of Commerce finds, under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C.1456(c)(3)(B)(iii)) that each activity covered by the EP is consistent with the objectives of the CZMA or is otherwise necessary in the interest of National security;

(3) If an affected State objects to the coastal zone consistency certification accompanying your approved EP after BOEM has approved your EP, you may either:

(i) Revise your EP to accommodate the State's objection and submit the revision to the Regional Supervisor for approval; or

(ii) Appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930, subpart H. The Secretary of Commerce will either:

(A) Grant your appeal by making the finding described in paragraph (d)(2) of this section; or

(B) Deny your appeal, in which case you may revise your EP as described in paragraph (d)(3)(i) of this section.

§ 550.282 Do I have to conduct post-approval monitoring?

After approving your EP, DPP, or DOCD, the Regional Supervisor may direct you to conduct monitoring programs, including monitoring in accordance with the ESA and the MMPA. You must retain copies of all monitoring data obtained or derived from your monitoring programs and make them available to the BOEM upon request. The Regional Supervisor may require you to:

(a) *Monitoring plans.* Submit monitoring plans for approval before you begin the work; and

(b) *Monitoring reports.* Prepare and submit reports that summarize and analyze data and information obtained or derived from your monitoring programs. The Regional Supervisor will specify requirements for preparing and submitting these reports.

§ 550.283 When must I revise or supplement the approved EP, DPP, or DOCD?

(a) *Revised OCS plans.* You must revise your approved EP, DPP, or DOCD when you propose to:

(1) Change the type of drilling rig (e.g., jack-up, platform rig, barge, submersible, semisubmersible, or drillship), production facility (e.g.,

caisson, fixed platform with piles, tension leg platform), or transportation mode (e.g., pipeline, barge);

(2) Change the surface location of a well or production platform by a distance more than that specified by the Regional Supervisor;

(3) Change the type of production or significantly increase the volume of production or storage capacity;

(4) Increase the emissions of an criteria air pollutant, VOC, or TSP to an amount that exceeds the amount specified in your approved EP, DPP, or DOCD;

(5) Significantly increase the amount of solid or liquid wastes to be handled or discharged;

(6) Request a new H_2S area classification, or increase the concentration of H_2S to a concentration greater than that specified by the Regional Supervisor;

(7) Change the location of your onshore support base either from one State to another or to a new base or a base requiring expansion; or

(8) Change any other activity specified by the Regional Supervisor.

(b) *Supplemental OCS plans.* You must supplement your approved EP, DPP, or DOCD when you propose to conduct activities on your lease(s) or unit that require approval of a license or permit which is not described in your approved EP, DPP, or DOCD. These types of changes are called supplemental OCS plans.

[76 FR 64623, Oct. 18, 2011, as amended at 85 FR 34936, June 5, 2020]

§ 550.284 How will BOEM require revisions to the approved EP, DPP, or DOCD?

(a) *Periodic review.* The Regional Supervisor will periodically review the activities you conduct under your approved EP, DPP, or DOCD and may require you to submit updated information on your activities. The frequency and extent of this review will be based on the significance of any changes in available information and onshore or offshore conditions affecting, or affected by, the activities in your approved EP, DPP, or DOCD.

(b) *Results of review.* The Regional Supervisor may require you to revise your approved EP, DPP, or DOCD based on this review. In such cases, the Regional Supervisor will inform you of the reasons for the decision.

§ 550.285 How do I submit revised and supplemental EPs, DPPs, and DOCDs?

(a) *Submittal.* You must submit to the Regional Supervisor any revisions and supplements to approved EPs, DPPs, or DOCDs for approval, whether you initiate them or the Regional Supervisor orders them.

(b) *Information.* Revised and supplemental EPs, DPPs, and DOCDs need include only information related to or affected by the proposed changes, including information on changes in expected environmental impacts.

(c) *Procedures.* All supplemental EPs, DPPs, and DOCDs, and those revised EPs, DPPs, and DOCDs that the Regional Supervisor determines are likely to result in a significant change in the impacts previously identified and evaluated, are subject to all of the procedures under §§ 550.231 through 550.235 for EPs and §§ 550.266 through 550.273 for DPPs and DOCDs.

§§ 550.286–550.295 [Reserved]

CONSERVATION INFORMATION DOCUMENTS (CID)

§ 550.296 When and how must I submit a CID or a revision to a CID?

(a) You must submit one original and two copies of a CID to the appropriate OCS Region at the same time you first submit your DOCD or DPP for any development of a lease or leases located in water depths greater than 400 meters (1,312 feet). You must also submit a CID for a Supplemental DOCD or DPP when requested by the Regional Supervisor. The submission of your CID must be accompanied by payment of the service fee listed in § 550.125.

(b) If you decide not to develop a reservoir you committed to develop in your CID, you must submit one original and two copies of a revision to the CID to the appropriate OCS Region. The revision to the CID must be submitted within 14 calendar days after making your decision not to develop the reservoir and before the reservoir is bypassed. The Regional Supervisor will

approve or disapprove any such revision to the original CID. If the Regional Supervisor disapproves the revision, you must develop the reservoir as described in the original CID.

§ 550.297 What information must a CID contain?

(a) You must base the CID on wells drilled before your CID submittal that define the extent of the reservoirs. You must notify BOEM of any well that is drilled to total depth during the CID evaluation period and you may be required to update your CID.

(b) You must include all of the following information if available. Information must be provided for each hydrocarbon-bearing reservoir that is penetrated by a well that would meet the producibility requirements of § 550.115 or § 550.116:

(1) General discussion of the overall development of the reservoir;

(2) Summary spreadsheets of well log data and reservoir parameters (*i.e.*, sand tops and bases, fluid contacts, net pay, porosity, water saturations, pressures, formation volume factor);

(3) Appropriate well logs, including digital well log (*i.e.*, gamma ray, resistivity, neutron, density, sonic, caliper curves) curves in an acceptable digital format;

(4) Sidewall core/whole core and pressure-volume-temperature analysis;

(5) Structure maps, with the existing and proposed penetration points and subsea depths for all wells penetrating the reservoirs, fluid contacts (or the lowest or highest known levels in the absence of actual contacts), reservoir boundaries, and the scale of the map;

(6) Interpreted structural cross sections and corresponding interpreted seismic lines or block diagrams, as necessary, that include all current wellbores and planned wellbores on the leases or units to be developed, the reservoir boundaries, fluid contacts, depth scale, stratigraphic positions, and relative biostratigraphic ages;

(7) Isopach maps of each reservoir showing the net feet of pay for each well within the reservoir identified at the penetration point, along with the well name, labeled contours, and scale;

(8) Estimates of original oil and gas in-place and anticipated recoverable oil and gas reserves, all reservoir parameters, and risk factors and assumptions;

(9) Plat map at the same scale as the structure maps with existing and proposed well paths, as well as existing and proposed penetrations;

(10) Wellbore schematics indicating proposed perforations;

(11) Proposed wellbore utility chart showing all existing and proposed wells, with proposed completion intervals indicated for each borehole;

(12) Appropriate pressure data, specified by date, and whether estimated or measured;

(13) Description of reservoir development strategies;

(14) Description of the enhanced recovery practices you will use or, if you do not plan to use such practices, an explanation of the methods you considered and reasons you do not intend to use them;

(15) For each reservoir you do not intend to develop:

(i) A statement explaining the reason(s) you will not develop the reservoir, and

(ii) Economic justification, including costs, recoverable reserve estimate, production profiles, and pricing assumptions; and

(16) Any other appropriate data you used in performing your reservoir evaluations and preparing your reservoir development strategies.

§ 550.298 How long will BOEM take to evaluate and make a decision on the CID?

(a) The Regional Supervisor will make a decision within 150 calendar days of receiving your CID. If BOEM does not act within 150 calendar days, your CID is considered approved.

(b) BOEM may suspend the 150-calendar-day evaluation period if there is missing, inconclusive, or inaccurate data, or when a well reaches total depth during the evaluation period. BOEM may also suspend the evaluation period when a well penetrating a hydrocarbon-bearing structure reaches total depth during the evaluation period and the data from that well is needed for the CID. You will receive written notification from the Regional Supervisor describing the additional

information that is needed, and the evaluation period will resume once BOEM receives the requested information.

(c) The Regional Supervisor will approve or deny your CID request based on your commitment to develop economically producible reservoirs according to sound conservation, engineering, and economic practices.

§ 550.299 What operations require approval of the CID?

You may not begin production before you receive BOEM approval of the CID.

Subpart C—Pollution Prevention and Control

§§ 550.300–550.301 [Reserved]

§ 550.302 Definitions concerning air quality.

For purposes of §§ 550.303 and 550.304 of this part:

Attainment area means, for any criteria 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 criteria air pollutant and VOC 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 criteria air pollutant and VOC.

Criteria air pollutant means any air pollutant for which the EPA has established a primary or secondary national ambient air quality standard pursuant to section 109 of the Clean Air Act.

Emission exemption threshold (EET) means the rate of projected emissions, calculated for a criteria air pollutant or VOC or TSP, above which a facility would be subject to the requirements of § 550.303(e) through (i) or § 550.304(b) through (e).

Emission offsets mean emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD).

Existing facility, as used in § 550.303, means an OCS facility described in an Exploration Plan, a Development and Production Plan, or a Development Operations Coordination Document approved before 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.

National Ambient Air Quality Standard (NAAQS) means a national air quality standard for any given criteria air pollutant, established pursuant to section 109 of the Clean Air Act.

Nonattainment area means, for any criteria 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 mean 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 that is emitted to the atmosphere as a vapor. Unreactive compounds are excluded from the preceding sentence of this definition.

[76 FR 64623, Oct. 18, 2011, as amended at 85 FR 34936, June 5, 2020]

§ 550.303 Facilities described in a new or revised Exploration Plan, Development and Production Plan, or Development Operations Coordination Document.

(a) *New plans.* All Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents 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 § 550.303 to existing facilities.* (1) The Regional Supervisor may review any Exploration Plan, Development and Production Plan, or Development Operations Coordination Document 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 § 550.218 or § 550.249 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, Development and Production Plans, and Development Operations Coordination Documents 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 an initial, modified, supplemental, or revised Exploration Plan, Development and Production Plan, or Development Operations Coordination Document is exempt from further air quality review, the lessee must use the highest annual-total amount of emissions from the facility calculated for each criteria air pollutant, VOC, and TSP listed in § 550.249(a) or § 550.218(a) and compare these emissions to the emission exemption threshold (EET) calculated using the following formulas: $EET = 3400*D^{2/3}$ for carbon monoxide (CO); and EET = 33.3*D for total suspended particulates (TSP), sulfur dioxide (SO_2), nitrogen oxides (NO_X), utilizing NO_2 as the indicator pollutant for NO_X, and VOC (where EET is the emission exemption threshold expressed in short 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 threshold (EET) for the corresponding criteria air pollutant, VOC, and TSP, the facility is exempt from further air quality review required under paragraphs (e) through (i) of this section.

(e) *Significance levels (SLs).* (1) For a facility not exempt under paragraph (d) of this section, the lessee must use a BOEM approved air quality model to determine whether projected emissions from the facility result in an onshore ambient air concentration above any SL set forth in the following table:

TABLE 1 TO PARAGRAPH (e)(1)—SIGNIFICANCE LEVELS (SLS)

	Averaging time				
	1 hour (mg/m³)	3 hour (μg/m³)	8 hour (mg/m³)	24 hour (μg/m³)	Annual (μg/m³)
Criteria Air Pollutant:					
Sulfur Dioxide		25.0		5.0	1.0
PM_{10}				5.0	1.0
$PM_{2.5}$				1.2	0.3
Nitrogen Dioxide [1]					1.0
Carbon Monoxide	2.0		0.5		

[1] NO_2 is the indicator pollutant for NO_X.

(2) In the event that the emissions of TSP exceed the EET for TSP, the lessee must use a BOEM approved air quality model to determine whether the projected emissions from the facility result in an onshore ambient air concentration above the SL for either PM_{10} or $PM_{2.5}$.

(f) *Significance determinations.* (1) The projected emissions of any criteria air pollutant from any facility that result in an onshore ambient air concentration above a SL determined under paragraph (e) of this section for that criteria air pollutant will be deemed to significantly affect the air quality of the onshore area for that criteria air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (d) of this section will be deemed to significantly affect the air quality of the onshore area for VOC.

(g) *Controls required.* (1) The projected emissions of any criteria air pollutant 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 criteria air pollutant from any facility which significantly affect the air quality of an attainment or unclassifiable area shall be reduced through the application of BACT.

(i)(A) 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	
SO_2	40	182	700

[1] For TSP—geometric; For SO_2—arithmetic.

(B) No concentration of an criteria 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 criteria 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 must apply BACT to reduce projected emissions of any criteria air pollutant or VOC from a temporary facility that 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 emission exemption thresholds.* If, during the review of a new, modified, or revised Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, 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.

[76 FR 64623, Oct. 18, 2011, as amended at 85 FR 34937, June 5, 2020]

§ 550.304 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 § 550.218 or § 550.249 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 must use the highest annual-total amount of emissions from the facility calculated for each criteria air pollutant, VOC, and TSP listed in § 550.249(a) or § 550.218(a) and compare these emissions to the emission exemption threshold (EET) calculated using the following formulas: $EET = 3400*D^{2/3}$ for carbon monoxide (CO); and EET = 33.3*D for total suspended particulates (TSP), sulfur dioxide (SO_2), nitrogen oxides (NO_X), utilizing NO_2 as the indicator pollutant for NO_X and VOC (where EET is the emission exemption threshold expressed in short 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 threshold (EET) for the corresponding criteria air pollutant, VOC, and TSP, the facility is exempt 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, the lessee must use a BOEM approved air quality model to determine whether the projected emissions from the facility result in an onshore ambient air concentration above any SL set forth in § 550.303(e). In the event that the emissions of TSP exceed the EET for TSP, the lessee must use a BOEM approved air quality model to determine whether the projected emissions from the facility result in an onshore ambient air concentration above the SL for either PM_{10} or $PM_{2.5}$.

(d) *Significance determinations.* (1) The projected emissions of any criteria air pollutant from any facility that result

in an onshore ambient air concentration above an SL determined under paragraph (c) of this section for that criteria air pollutant, will be deemed to significantly affect the air quality of the onshore area for that criteria air pollutant.

(2) The projected emissions of VOC from any facility, which is not exempt under paragraph (b) of this section, will be deemed to significantly affect the air quality of the onshore area for VOC.

(e) *Controls required.* (1) The projected emissions of any criteria air pollutant or VOC that significantly affect the air quality of an onshore area must 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 30 CFR 250.174.

(f) *Review of facilities with emissions below the emission exemption thresholds.* 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.

[76 FR 64623, Oct. 18, 2011, as amended at 85 FR 34937, June 5, 2020]

Subpart D—Leasing Maps and Diagrams

§ 550.400 Leasing maps and diagrams.

(a) Any area of the OCS, which has been appropriately platted as provided in paragraph (b) of this section, may be leased for any mineral not included in an existing 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) BOEM will prepare leasing maps and official protraction diagrams of areas of the OCS. The areas included in each mineral lease will be in accordance with the appropriate leasing map or official protraction diagram.

[81 FR 18152, Mar. 30, 2016]

Subparts E–I [Reserved]

Subpart J—Pipelines and Pipeline Rights-of-Way

§ 550.1011 Bond requirements for pipeline right-of-way holders.

(a) When you apply for, or are the holder of, a right-of-way, you must:

(1) Provide and maintain a $300,000 bond (in addition to the bond coverage required in 30 CFR part 256 and 30 CFR part 556) that guarantees compliance with all the terms and conditions of the rights-of-way you hold in an OCS area; and

(2) Provide additional security if the Regional Director determines that a bond in excess of $300,000 is needed.

(b) For the purpose of this paragraph, there are three areas:

(1) The Gulf of Mexico and the area offshore the Atlantic Coast;

(2) The areas offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; and

(3) The area offshore the Coast of Alaska.

(c) 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.

(d) 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.

Subpart K—Oil and Gas Production Requirements.

WELL TESTS AND SURVEYS

§ 550.1153 When must I conduct a static bottomhole pressure survey?

(a) You must conduct a static bottomhole pressure survey under the following conditions:

If you have . . .	Then you must conduct . . .
(1) A new producing reservoir,	A static bottomhole pressure survey within 90 days after the date of first continuous production.
(2) A reservoir with three or more producing completions,	Annual static bottomhole pressure surveys in a sufficient number of key wells to establish an average reservoir pressure. The Regional Supervisor may require that bottomhole pressure surveys be performed on specific wells.

(b) Your bottomhole pressure survey must meet the following requirements:

(1) You must shut-in the well for a minimum period of 4 hours to ensure stabilized conditions; and

(2) The bottomhole pressure survey must consist of a pressure measurement at mid-perforation, and pressure measurements and gradient information for at least four gradient stops coming out of the hole.

(c) You must submit to the Regional Supervisor the results of all static bottomhole pressure surveys on Form BOEM–140, Bottomhole Pressure Survey Report, within 60 days after the date of the survey.

(d) The Regional Supervisor may grant a departure from the requirement to run a static bottomhole pressure survey. To request a departure, you must submit a justification, along with Form BOEM–0140, Bottomhole Pressure Survey Report, showing a calculated bottomhole pressure or any measured data.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

CLASSIFYING RESERVOIRS

§ 550.1154 How do I determine if my reservoir is sensitive?

(a) You must determine whether each reservoir is sensitive. You must classify the reservoir as sensitive if:

(1) Under initial conditions it is an oil reservoir with an associated gas cap;

(2) At any time there are near-critical fluids; or

(3) The reservoir is undergoing enhanced recovery.

(b) For the purposes of this subpart, near-critical fluids are:

(1) Those fluids that occur in high temperature, high-pressure reservoirs where it is not possible to define the liquid-gas contact; or

(2) Fluids in reservoirs that are near bubble point or dew point conditions.

(c) The Regional Supervisor may reclassify a reservoir when available information warrants reclassification.

(d) If available information indicates that a reservoir previously classified as non-sensitive is now sensitive, you must submit a request to the Regional Supervisor to reclassify the reservoir. You must include supporting information, as listed in the table in § 550.1167, with your request.

(e) If information indicates that a reservoir previously classified as sensitive is now non-sensitive, you may submit a request to the Regional Supervisor to reclassify the reservoir. You must include supporting information, as listed in the table in § 550.1167, with your request.

§ 550.1155 What information must I submit for sensitive reservoirs?

You must submit to the Regional Supervisor an original and two copies of Form BOEM–0127; one of the copies must be a public information copy in accordance with §§ 550.186 and 550.197, and marked ''Public Information.'' You must also submit two copies of the supporting information, as listed in the table in § 550.1167. You must submit this information:

(a) Within 45 days after beginning production from the reservoir or discovering that it is sensitive;

(b) At least once during the calendar year, but you do not need to resubmit unrevised structure maps (§ 550.1167(a)(2)) or previously submitted well logs (§ 550.1167(c)(1));

(c) Within 45 days after you revise reservoir parameters; and

(d) Within 45 days after the Regional Supervisor classifies the reservoir as sensitive under § 550.1154(c).

OTHER REQUIREMENTS

§ 550.1165 What must I do for enhanced recovery operations?

(a) [Reserved]

(b) Before initiating enhanced recovery operations, you must submit a proposed plan to the BSEE Regional Supervisor and receive approval for pressure maintenance, secondary or tertiary recovery, cycling, and similar recovery operations intended to increase the ultimate recovery of oil and gas from a reservoir. The proposed plan must include, for each project reservoir, a geologic and engineering overview, Form BOEM–0127 (submitted to BOEM) and supporting data as required in § 550.1167, 30 CFR 250.1167, and any additional information required by the BSEE Regional Supervisor.

(c) [Reserved]

§ 550.1166 What additional reporting is required for developments in the Alaska OCS Region?

(a)–(b) [Reserved]

(c) Every time you are required to submit Form BOEM–0127 under § 550.1155, you must request an MER for each producing sensitive reservoir in the Alaska OCS Region, unless otherwise instructed by the Regional Supervisor.

§ 550.1167 What information must I submit with forms and for approvals?

You must submit the supporting information listed in the following table with the form identified in column 1 and for the approval required under this subpart identified in column 2:

	SRI BOEM–0127 (2 copies)	Reservoir reclassification
(a) Maps:		
(1) Base map with surface, bottomhole, and completion locations with respect to the unit or lease line and the orientation of representative seismic lines or cross-sections	.....	
(2) Structure maps with penetration point and subsea depth for each well penetrating the reservoirs, highlighting subject wells; reservoir boundaries; and original and current fluid levels	√	√
(3) Net sand isopach with total net sand penetrated for each well, identified at the penetration point	*	
(4) Net hydrocarbon isopach with net feet of pay for each well, identified at the penetration point	*	
(b) Seismic data:		
(1) Representative seismic lines, including strike and dip lines that confirm the structure; indicate polarity	.....	
(2) Amplitude extraction of seismic horizon, if applicable	.....	√
(c) Logs:		
(1) Well log sections with tops and bottoms of the reservoir(s) and proposed or existing perforations	√	√
(2) Structural cross-sections showing the subject well and nearby wells	.....	√
(d) Engineering data:		

	SRI BOEM–0127 (2 copies)	Reservoir reclassification
(1) Estimated recoverable reserves for each well completion in the reservoir; total recoverable reserves for each reservoir; method of calculation; reservoir parameters used in volumetric and decline curve analysis	√	
(2) Well schematics showing current and proposed conditions		
(3) The drive mechanism of each reservoir	√	√
(4) Pressure data, by date, and whether they are estimated or measured		√
(5) Production data and decline curve analysis indicative of the reservoir performance		√
(6) Reservoir simulation with the reservoir parameters used, history matches, and prediction runs (include proposed development scenario)		*
(e) General information:		
(1) Detailed economic analysis		
(2) Reservoir name and whether or not it is competitive as defined under § 250.105	√	√
(3) Operator name, lessee name(s), block, lease number, royalty rate, and unit number (if applicable) of all relevant leases		
(4) Geologic overview of project		√
(5) Explanation of why the proposed completion scenario will maximize ultimate recovery		
(6) List of all wells in subject reservoirs that have ever produced or been used for injection		√

√ Required.
* Additional items the Regional Supervisor may request.
Note: All maps must be at a standard scale and show lease and unit lines. The Regional Supervisor may waive submittal of some of the required data on a case-by-case basis.

(f) Depending on the type of approval requested, you must submit the appropriate payment of the service fee(s) listed in § 550.125, according to the instructions in § 550.126.

Subparts L–M [Reserved]

Subpart N—Outer Continental Shelf Civil Penalties

OUTER CONTINENTAL SHELF LANDS ACT CIVIL PENALTIES

§ 550.1400 How does BOEM begin the civil penalty process?

This subpart explains BOEM's civil penalty procedures whenever a lessee, operator or other person engaged in oil, gas, sulphur or other minerals operations in the OCS has a violation. Whenever BOEM determines, on the basis of available evidence, that a violation occurred and a civil penalty review is appropriate, it will prepare a case file. BOEM will appoint a Reviewing Officer.

§ 550.1401 Index table.

The following table is an index of the sections in this subpart:

(a) Definitions	§ 550.1402
(b) What is the maximum civil penalty?	§ 550.1403
(c) Which violations will BOEM review for potential civil penalties?	§ 550.1404
(d) When is a case file developed?	§ 550.1405
(e) When will BOEM notify me and provide penalty information?	§ 550.1406
(f) How do I respond to the letter of notification?	§ 550.1407
(g) When will I be notified of the Reviewing Officer's decision?	§ 550.1408
(h) What are my appeal rights?	§ 550.1409

§ 550.1402 Definitions.

Terms used in this subpart have the following meaning:

Case file means a BOEM document file containing information and the record of evidence related to the alleged violation.

Civil penalty means a fine. It is a BOEM regulatory enforcement tool used in addition to Notices of Incidents of Noncompliance and directed suspensions of production or other operations.

Reviewing Officer means a BOEM employee assigned to review case files and assess civil penalties.

Violation means failure to comply with the Outer Continental Shelf Lands Act (OCSLA) or any other applicable laws, with any regulations issued under the OCSLA, or with the terms or provisions of leases, licenses, permits, rights-of-way, or other approvals issued under the OCSLA.

Violator means a person responsible for a violation.

§ 550.1403 What is the maximum civil penalty?

The maximum civil penalty is $48,862 per day per violation.

[87 FR 15335, Mar. 18, 2022]

§ 550.1404 Which violations will BOEM review for potential civil penalties?

BOEM will review each of the following violations for potential civil penalties:

(a) Violations that you do not correct within the period BOEM grants;

(b)–(c) [Reserved]

(d) Violations of the oil spill financial responsibility requirements at 30 CFR part 553.

§ 550.1405 When is a case file developed?

BOEM will develop a case file during its investigation of the violation, and forward it to a Reviewing Officer if any of the conditions in § 550.1404 exist. The Reviewing Officer will review the case file and determine if a civil penalty is appropriate. The Reviewing Officer may administer oaths and issue subpoenas requiring witnesses to attend meetings, submit depositions, or produce evidence.

§ 550.1406 When will BOEM notify me and provide penalty information?

If the Reviewing Officer determines that a civil penalty should be assessed, the Reviewing Officer will send the violator a letter of notification. The letter of notification will include:

(a) The amount of the proposed civil penalty;

(b) Information on the violation(s); and

(c) Instruction on how to obtain a copy of the case file, schedule a meeting, submit information, or pay the penalty.

§ 550.1407 How do I respond to the letter of notification?

You have 30 calendar days after you receive the Reviewing Officer's letter to either:

(a) Request, in writing, a meeting with the Reviewing Officer;

(b) Submit additional information; or

(c) Pay the proposed civil penalty.

§ 550.1408 When will I be notified of the Reviewing Officer's decision?

At the end of the 30 calendar days or after the meeting and submittal of additional information, the Reviewing Officer will review the case file, including all information you submitted, and send you a decision. The decision will include the amount of any final civil penalty, the basis for the civil penalty, and instructions for paying or appealing the civil penalty.

§ 550.1409 What are my appeal rights?

(a) When you receive the Reviewing Officer's final decision, you have 60 days to either pay the penalty or file an appeal in accordance with 30 CFR part 590, subpart A.

(b) If you file an appeal, you must either:

(1) Submit a surety bond in the amount of the penalty to the appropriate Leasing Office in the Region where the penalty was assessed, following instructions that the Reviewing Officer will include in the final decision; or

(2) Notify the appropriate Leasing Office, in the Region where the penalty was assessed, that you want your lease-specific/area-wide bond on file to be

used as the bond for the penalty amount.

(c) If you choose the alternative in paragraph (b)(2) of this section, the BOEM Regional Director may require additional security (*i.e.*, security in excess of your existing bond) to ensure sufficient coverage during an appeal. In that event, the Regional Director will require you to post the supplemental bond with the regional office in the same manner as under § 556.53(d) through (f) of this chapter. If the Regional Director determines the appeal should be covered by a lease-specific abandonment account then you must establish an account that meets the requirements of § 556.56.

(d) If you do not either pay the penalty or file a timely appeal, BOEM will take one or more of the following actions:

(1) We will collect the amount you were assessed, plus interest, late payment charges, and other fees as provided by law, from the date you received the Reviewing Officer's final decision until the date we receive payment;

(2) We may initiate additional enforcement, including, if appropriate, cancellation of the lease, right-of-way, license, permit, or approval, or the forfeiture of a bond under this part; or

(3) We may bar you from doing further business with the Federal Government according to Executive Orders 12549 and 12689, and section 2455 of the Federal Acquisition Streamlining Act of 1994, 31 U.S.C. 6101. The Department of the Interior's regulations implementing these authorities are found at 43 CFR part 12, subpart D.

FEDERAL OIL AND GAS ROYALTY MANAGEMENT ACT CIVIL PENALTIES DEFINITIONS

§ 550.1450 What definitions apply to this subpart?

The terms used in this subpart have the same meaning as in 30 U.S.C. 1702.

PENALTIES AFTER A PERIOD TO CORRECT

§ 550.1451 What may BOEM do if I violate a statute, regulation, order, or lease term relating to a Federal oil and gas lease?

(a) If we believe that you have not followed any requirement of a statute, regulation, order, or lease term for any Federal oil or gas lease, we may send you a Notice of Noncompliance informing you what the violation is and what you need to do to correct it to avoid civil penalties under 30 U.S.C. 1719(a) and (b).

(b) We will serve the Notice of Noncompliance by registered mail or personal service using the most current address on file as maintained by the BOEM Leasing Office in your respective Region.

§ 550.1452 What if I correct the violation?

The matter will be closed if you correct all of the violations identified in the Notice of Noncompliance within 20 days after you receive the Notice (or within a longer time period specified in the Notice).

§ 550.1453 What if I do not correct the violation?

(a) We may send you a Notice of Civil Penalty if you do not correct all of the violations identified in the Notice of Noncompliance within 20 days after you receive the Notice of Noncompliance (or within a longer time period specified in that Notice). The Notice of Civil Penalty will tell you how much penalty you must pay for each day, beginning with the date of the Notice of Noncompliance, for each violation identified in the Notice of Noncompliance for as long as you do not correct the violation. The maximum civil penalty amount for each day for each uncorrected violation is as specified in 30 CFR 1241.52(a)(2).

(b) If you do not correct all of the violations identified in the Notice of Noncompliance within 40 days after you receive the Notice of Noncompliance (or 20 days following the expiration of a longer time period specified in that Notice), we may increase the penalty for each day, beginning with the date of the Notice of Noncompliance,

for each violation for as long as you do not correct the violation. The maximum civil penalty amount for each day for each uncorrected violation is as specified in 30 CFR 1241.52(b).

[86 FR 38559, July 22, 2021]

§ 550.1454 How may I request a hearing on the record on a Notice of Noncompliance?

You may request a hearing on the record on a Notice of Noncompliance by filing a request within 30 days of the date you received the Notice of Noncompliance with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 351 South West Temple, Suite 6.300, Salt Lake City, Utah 84101. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

§ 550.1455 Does my request for a hearing on the record affect the penalties?

(a) If you do not correct the violations identified in the Notice of Noncompliance, the penalties will continue to accrue even if you request a hearing on the record.

(b) You may petition the Hearings Division (Departmental) of the Office of Hearings and Appeals, to stay the accrual of penalties pending the hearing on the record and a decision by the Administrative Law Judge under § 550.1472.

(1) You must file your petition within 45 calendar days of receiving the Notice of Noncompliance.

(2) To stay the accrual of penalties, you must post a bond or other surety instrument, or demonstrate financial solvency, using the standards and requirements as prescribed in §§ 550.1490 through 550.1497, for the principal amount of any unpaid amounts due that are the subject of the Notice of Noncompliance, including interest thereon, plus the amount of any penalties accrued before the date a stay becomes effective.

(3) The Hearings Division will grant or deny the petition under 43 CFR 4.21(b).

§ 550.1456 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

(a) You may request a hearing on the record to challenge only the amount of a civil penalty when you receive a Notice of Civil Penalty, if you did not previously request a hearing on the record under § 550.1454. If you did not request a hearing on the record on the Notice of Noncompliance under § 550.1454, you may not contest your underlying liability for civil penalties.

(b) You must file your request within 10 days after you receive the Notice of Civil Penalty with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 351 South West Temple, Suite 6.300, Salt Lake City, Utah 84101.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

PENALTIES WITHOUT A PERIOD TO CORRECT

§ 550.1460 May I be subject to penalties without prior notice and an opportunity to correct?

The Federal Oil and Gas Royalty Management Act sets out several specific violations for which penalties accrue without an opportunity to first correct the violation.

(a) [Reserved]

(b) Under 30 U.S.C. 1719(d), you may be subject to civil penalties up to the maximum amount specified in 30 CFR 1241.60(b)(2) for each violation for each day that it continues if you:

(1) Knowingly or willfully prepare, maintain, or submit false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information.

(2) [Reserved]

[76 FR 64623, Oct. 18, 2011, as amended at 86 FR 38559, July 22, 2021]

§ 550.1461 How will BOEM inform me of violations without a period to correct?

We will inform you of any violation, without a period to correct, by issuing a Notice of Noncompliance and Civil Penalty explaining the violation, how

to correct it, and the penalty assessment. We will serve the Notice of Noncompliance and Civil Penalty by registered mail or personal service using your address of record as specified under 30 CFR part 1218, subpart H.

§ 550.1462 How may I request a hearing on the record on a Notice of Noncompliance regarding violations without a period to correct?

You may request a hearing on the record of a Notice of Noncompliance regarding violations without a period to correct by filing a request within 30 days after you receive the Notice of Noncompliance with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 351 South West Temple, Suite 6.300, Salt Lake City, Utah 84101. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

§ 550.1463 Does my request for a hearing on the record affect the penalties?

(a) If you do not correct the violations identified in the Notice of Noncompliance regarding violations without a period to correct, the penalties will continue to accrue even if you request a hearing on the record.

(b) You may ask the Hearings Division (Departmental) to stay the accrual of penalties pending the hearing on the record and a decision by the Administrative Law Judge under § 550.1472.

(1) You must file your petition within 45 calendar days after you receive the Notice of Noncompliance.

(2) To stay the accrual of penalties, you must post a bond or other surety instrument, or demonstrate financial solvency, using the standards and requirements as prescribed in §§ 550.1490 through 550.1497, for the principal amount of any unpaid amounts due that are the subject of the Notice of Noncompliance, including interest thereon, plus the amount of any penalties accrued before the date a stay becomes effective.

(3) The Hearings Division will grant or deny the petition under 43 CFR 4.21(b).

§ 550.1464 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

(a) You may request a hearing on the record to challenge only the amount of a civil penalty when you receive a Notice of Civil Penalty regarding violations without a period to correct, if you did not previously request a hearing on the record under § 550.1462. If you did not request a hearing on the record on the Notice of Noncompliance under § 550.1462, you may not contest your underlying liability for civil penalties.

(b) You must file your request within 10 days after you receive Notice of Civil Penalty with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 351 South West Temple, Suite 6.300, Salt Lake City, Utah 84101.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

GENERAL PROVISIONS

§ 550.1470 How does BOEM decide what the amount of the penalty should be?

We determine the amount of the penalty by considering the severity of the violations, your history of compliance, and if you are a small business.

§ 550.1471 Does the penalty affect whether I owe interest?

If you do not pay the penalty by the date required under § 550.1475(d), BOEM will assess you late payment interest on the penalty amount at the same rate interest is assessed under 30 CFR 1218.54.

§ 550.1472 How will the Office of Hearings and Appeals conduct the hearing on the record?

If you request a hearing on the record under § 550.1454, § 550.1456, § 550.1462, or § 550.1464, the hearing will be conducted by a Departmental Administrative Law Judge from the Office of Hearings and Appeals. After the hearing, the Administrative Law Judge will issue a decision in accordance with

the evidence presented and applicable law.

§ 550.1473 How may I appeal the Administrative Law Judge's decision?

If you are adversely affected by the Administrative Law Judge's decision, you may appeal that decision to the Interior Board of Land Appeals under 43 CFR part 4, subpart E.

§ 550.1474 May I seek judicial review of the decision of the Interior Board of Land Appeals?

Under 30 U.S.C. 1719(j), you may seek judicial review of the decision of the Interior Board of Land Appeals. A suit for judicial review in the District Court will be barred unless filed within 90 days after the final order.

§ 550.1475 When must I pay the penalty?

(a) You must pay the amount of the Notice of Civil Penalty issued under § 550.1453 or § 550.1461, if you do not request a hearing on the record under § 550.1454, § 550.1456, § 550.1462, or § 550.1464

(b) If you request a hearing on the record under § 550.1454, § 550.1456, § 550.1462, or § 550.1464, but you do not appeal the determination of the Administrative Law Judge to the Interior Board of Land Appeals under § 550.1473, you must pay the amount assessed by the Administrative Law Judge.

(c) If you appeal the determination of the Administrative Law Judge to the Interior Board of Land Appeals, you must pay the amount assessed in the IBLA decision.

(d) You must pay the penalty assessed within 40 days after:

(1) You received the Notice of Civil Penalty, if you did not request a hearing on the record under either § 550.1454, § 550.1456, § 550.1462, or § 550.1464;

(2) You received an Administrative Law Judge's decision under § 550.1472, if you obtained a stay of the accrual of penalties pending the hearing on the record under § 550.1455(b) or § 550.1463(b) and did not appeal the Administrative Law Judge's determination to the IBLA under § 550.1473;

(3) You received an IBLA decision under § 550.1473 if the IBLA continued the stay of accrual of penalties pending its decision and you did not seek judicial review of the IBLA's decision; or

(4) A final non-appealable judgment of a court of competent jurisdiction is entered, if you sought judicial review of the IBLA's decision and the Department or the appropriate court suspended compliance with the IBLA's decision pending the adjudication of the case.

(e) If you do not pay, that amount is subject to collection under the provisions of § 550.1477.

§ 550.1476 Can BOEM reduce my penalty once it is assessed?

Under 30 U.S.C. 1719(g), the Director or his or her delegate may compromise or reduce civil penalties assessed under this part.

§ 550.1477 How may BOEM collect the penalty?

(a) BOEM may use all available means to collect the penalty including, but not limited to:

(1) Requiring the lease surety, for amounts owed by lessees, to pay the penalty;

(2) Deducting the amount of the penalty from any sums the United States owes to you; and

(3) Using judicial process to compel your payment under 30 U.S.C. 1719(k).

(b) If the Department uses judicial process, or if you seek judicial review under § 550.1474 and the court upholds assessment of a penalty, 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 § 550.1474. The amount of any penalty, as finally determined, may be deducted from any sum owing to you by the United States.

CRIMINAL PENALTIES

§ 550.1480 May the United States criminally prosecute me for violations under Federal oil and gas leases?

If you commit an act for which a civil penalty is provided at 30 U.S.C. 1719(d) and § 550.1460(b), the United States may pursue criminal penalties as provided at 30 U.S.C. 1720, in addition to any authority for prosecution under other statutes.

BONDING REQUIREMENTS

§ 550.1490 What standards must my BOEM-specified surety instrument meet?

(a) A BOEM-specified surety instrument must be in a form specified in BOEM instructions. BOEM will give you written information and standard forms for BOEM-specified surety instrument requirements.

(b) BOEM will use a bank-rating service to determine whether a financial institution has an acceptable rating to provide a surety instrument adequate to indemnify the lessor from loss or damage.

(1) Administrative appeal bonds must be issued by a qualified surety company which the Department of the Treasury has approved.

(2) Irrevocable letters of credit or certificates of deposit must be from a financial institution acceptable to BOEM with a minimum 1-year period of coverage subject to automatic renewal up to 5 years.

§ 550.1491 How will BOEM determine the amount of my bond or other surety instrument?

(a) BOEM bond-approving officer may approve your surety if he or she determines that the amount is adequate to guarantee payment. The amount of your surety may vary depending on the form of the surety and how long the surety is effective.

(1) The amount of the BOEM-specified surety instrument must include the principal amount owed under the Notice of Noncompliance or Notice of Civil Penalty plus any accrued interest we determine is owed plus projected interest for a 1-year period.

(2) Treasury book-entry bond or note amounts must be equal to at least 120 percent of the required surety amount.

(b) If your appeal is not decided within 1 year from the filing date, you must increase the surety amount to cover additional estimated interest for another 1-year period. You must continue to do this annually on the date your appeal was filed. We will determine the additional estimated interest and notify you of the amount so you can amend your surety instrument.

(c) You may submit a single surety instrument that covers multiple appeals. You may change the instrument to add new amounts under appeal or remove amounts that have been adjudicated in your favor or that you have paid, if you:

(1) Amend the single surety instrument annually on the date you filed your first appeal; and

(2) Submit a separate surety instrument for new amounts under appeal until you amend the instrument to cover the new appeals.

FINANCIAL SOLVENCY REQUIREMENTS

§ 550.1495 How do I demonstrate financial solvency?

(a) To demonstrate financial solvency under this part, you must submit an audited consolidated balance sheet, and, if requested by the BOEM bond-approving officer, up to 3 years of tax returns to BOEM using the U.S. Postal Service, private delivery, courier, or overnight delivery at:

(1) For Alaska OCS: BOEM Alaska OCS Region, 3801 Centerpoint Drive, Suite 500, Anchorage, AK 99503, (907) 334–5200.

(2) For Gulf of Mexico and Atlantic OCS: BOEM Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard, New Orleans, LA 70123–2394, (800) 200–4853.

(3) For Pacific OCS: BOEM Pacific OCS Region, 760 Paseo Camarillo, Suite 102 (CM 102), Camarillo, CA 93010, (805) 384–6305.

(b) You must submit an audited consolidated balance sheet annually, and, if requested, additional annual tax returns on the date BOEM first determined that you demonstrated financial solvency as long as you have active appeals, or whenever BOEM requests.

(c) If you demonstrate financial solvency in the current calendar year, you are not required to redemonstrate financial solvency for new appeals of orders during that calendar year unless you file for protection under any provision of the U.S. Bankruptcy Code (Title 11 of the United States Code), or BOEM notifies you that you must redemonstrate financial solvency.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

§ 550.1496 How will BOEM determine if I am financially solvent?

(a) BOEM bond-approving officer will determine your financial solvency by examining your total net worth, including, as appropriate, the net worth of your affiliated entities.

(b) If your net worth, minus the amount we would require as surety under §§ 550.1490 and 550.1491 for all orders you have appealed is greater than $300 million, you are presumptively deemed financially solvent, and we will not require you to post a bond or other surety instrument.

(c) If your net worth, minus the amount we would require as surety under §§ 550.1490 and 550.1491 for all orders you have appealed is less than $300 million, you must submit the following to BOEM by one of the methods in § 550.1495(a):

(1) A written request asking us to consult a business-information, or credit-reporting service or program to determine your financial solvency; and

(2) A nonrefundable $50 processing fee:

(i) You must pay the processing fee to us following the requirements for making payments found in 30 CFR 550.126. You are required to use Electronic Funds Transfer (EFT) for these payments;

(ii) You must submit the fee with your request under paragraph (c)(1) of this section, and then annually on the date we first determined that you demonstrated financial solvency, as long as you are not able to demonstrate financial solvency under paragraph (a) of this section and you have active appeals.

(d) If you request that we consult a business-information or credit-reporting service or program under paragraph (c) of this section:

(1) We will use criteria similar to that which a potential creditor would use to lend an amount equal to the bond or other surety instrument we would require under §§ 550.1490 and 550.1491;

(2) For us to consider you financially solvent, the business-information or credit-reporting service or program must demonstrate your degree of risk as low to moderate:

(i) If our bond-approving officer determines that the business-information or credit-reporting service or program information demonstrates your financial solvency to our satisfaction, our bond-approving officer will not require you to post a bond or other surety instrument under §§ 550.1490 and 550.1491;

(ii) If our bond-approving officer determines that the business-information or credit-reporting service or program information does not demonstrate your financial solvency to our satisfaction, our bond-approving officer will require you to post a bond or other surety instrument under §§ 550.1490 and 550.1491 or pay the obligation.

§ 550.1497 When will BOEM monitor my financial solvency?

(a) If you are presumptively financially solvent under § 550.1496(b), BOEM will determine your net worth as described under §§ 550.1496(b) and (c) to evaluate your financial solvency at least annually on the date we first determined that you demonstrated financial solvency as long as you have active appeals and each time you appeal a new order.

(b) If you ask us to consult a business-information or credit-reporting service or program under § 550.1496(c), we will consult a service or program annually as long as you have active appeals and each time you appeal a new order.

(c) If our bond-approving officer determines that you are no longer financially solvent, you must post a bond or other BOEM-specified surety instrument under §§ 550.1490 and 550.1491.

Subparts O–S [Reserved]

PART 551—GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

Sec.

551.1 Definitions.
551.2 Purpose of this part.
551.3 Authority and applicability of this part.
551.4 Types of G&G activities that require permits or Notices.
551.5 Applying for permits or filing Notices.

551.6 Obligations and rights under a permit or a Notice.
551.7 Test drilling activities under a permit.
551.8 Inspection and reporting requirements for activities under a permit.
551.9 Temporarily stopping, canceling, or relinquishing activities approved under a permit.
551.10 Penalties and appeals.
551.11 Submission, inspection, and selection of geological data and information collected under a permit and processed by permittees or third parties.
551.12 Submission, inspection, and selection of geophysical data and information collected under a permit and processed by permittees or third parties.
551.13 Reimbursement for the costs of reproducing data and information and certain processing costs.
551.14 Protecting and disclosing data and information submitted to BOEM under a permit.
551.15 Authority for information collection.

AUTHORITY: Section 104, Public Law 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Public Law 109–432, Div C, Title I, 120 Stat. 3000; 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334; 33 U.S.C. 2704, 2716; E.O. 12777, as amended; 43 U.S.C. 1331 *et seq.*, 43 U.S.C. 1337.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

§ 551.1 Definitions.

Terms used in this part have the following meaning:

Act means the Outer Continental Shelf Lands Act (OCSLA), as amended (43 U.S.C. 1331 *et seq.*).

Analyzed geological information means data collected under a permit or a lease that 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 from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

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.

Archaeological resources mean any material remains of human life or activities that are at least 50 years of age and of archaeological interest.

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors that 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 shorelines of the several coastal States and extends seaward to the outer limit of the U.S. territorial sea.

Coastal Zone Management Act means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 *et seq.*).

Data means facts, statistics, measurements, or samples that have not been analyzed, processed, or interpreted.

Deep stratigraphic test means drilling that involves the penetration into the sea bottom of more than 500 feet (152 meters).

Director means the Director of the Bureau of Ocean Energy Management, U.S. Department of the Interior, or a subordinate authorized to act on the Director's behalf.

Exploration means the commercial search for oil, gas, and sulphur. Activities classified as exploration include, but are not limited to:

(1) Geological and geophysical marine and airborne surveys where magnetic, gravity, seismic reflection, seismic refraction, gas sniffers, coring, or other systems are used to detect or imply the presence of oil, gas, or sulphur; and

(2) Any drilling, whether on or off a geological structure.

Geological and geophysical scientific research means any oil, gas, or sulphur related investigation conducted in the OCS for scientific and/or research purposes. Geological, geophysical, and geochemical data and information gathered and analyzed are made available to the public for inspection and reproduction at the earliest practicable

time. The term does not include commercial geological or geophysical exploration or research.

Geological exploration means exploration that uses geological and geochemical techniques (e.g., coring and test drilling, well logging, and bottom sampling) to produce data and information on oil, gas, and sulphur resources in support of possible exploration and development activities. The term does not include geological scientific research.

Geological information means geological or geochemical data that have been analyzed, processed, or interpreted.

Geophysical data means measurements that have not been processed or interpreted.

Geophysical exploration means exploration that utilizes geophysical techniques (e.g., gravity, magnetic, electromagnetic, or seismic) to produce data and information on oil, gas, and sulphur resources in support of possible exploration and development activities. The term does not include geophysical scientific research.

Geophysical information means geophysical data that have been processed or interpreted.

Governor means the Governor of a State or the person or entity lawfully designated to exercise the powers granted to a 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.

Hydrocarbon occurrence 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.

Interpreted geological information means knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geological data and analyzed and processed geologic information.

Interpreted geophysical information means knowledge, often in the form of seismic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

Lease means an agreement 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.

Lessee means a person who has entered into, or is the BOEM approved assignee of, a lease with the United States to explore for, develop, and produce the leased minerals. The term ''lessee'' also includes an owner of operating rights.

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the quality of the marine ecosystem in the coastal zone and in the OCS.

Material remains mean physical evidence of human habitation, occupation, use, or activity, including the site, location, or context in which such evidence is situated.

Minerals mean 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).

Notice means a written statement of intent to conduct geological or geophysical scientific research related to oil, gas, and sulphur in the OCS other than under a permit.

Oil, gas, and sulphur means oil, gas, sulphur, geopressured-geothermal, and associated resources.

Outer Continental Shelf (OCS) means all submerged lands lying 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.

Permit means the contract or agreement, other than a lease, issued pursuant to this part, under which a person acquires the right to conduct on the OCS, in accordance with appropriate statutes, regulations, and stipulations:

(1) Geological exploration for mineral resources;

(2) Geophysical exploration for mineral resources;

(3) Geological scientific research; or

(4) Geophysical scientific research.

Permittee means the person authorized by a permit issued pursuant to this part to conduct activities on the OCS.

Person means a citizen or national of the United States; an alien lawfully admitted for permanent residence in the United States as defined in section 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 or anyone operating in a manner provided for by treaty or other applicable international agreements. The term does not include Federal agencies.

Processed geological or geophysical information means data collected under a permit and later processed or reprocessed. 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. Reprocessing is the additional processing other than ordinary processing used in the general course of evaluation. Reprocessing operations may include varying identified parameters for the detailed study of a specific problem area. Reprocessing may occur several years after the original processing date. Reprocessing is determined to be completed on the date that the reprocessed information is first available in a useable format for in-house interpretation by BOEM or the permittee, or becomes first available to third parties via sale, trade, license agreement, or other means.

Secretary means the Secretary of the Interior or a subordinate authorized to act on the Secretary's behalf.

Shallow test drilling means drilling into the sea bottom to depths less than those specified in the definition of a deep stratigraphic test.

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.

Third Party means any person other than the permittee or a representative of the United States, including all persons who obtain data or information acquired under a permit from the permittee, or from another third party, by sale, trade, license agreement, or other means.

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 under the Act.

You means a person who applies for and/or obtains a permit, or files a Notice to conduct geological or geophysical exploration or scientific research related to oil, gas, and sulphur in the OCS.

§ 551.2 Purpose of this part.

(a) To allow you to conduct G&G activities in the OCS related to oil, gas, and sulphur on unleased lands or on lands under lease to a third party.

(b) To ensure that you carry out G&G activities in a safe and environmentally sound manner so as to prevent harm or damage to, or waste of, any natural resources (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.

(c) To inform you and third parties of your legal and contractual obligations.

(d) To inform you and third parties of the U.S. Government's rights to access G&G data and information collected under permit in the OCS, reimbursement for submittal of data and information, and the proprietary terms of

data and information submitted to, and retained by, BOEM.

§ 551.3 Authority and applicability of this part.

BOEM authorizes you to conduct exploration or scientific research activities under this part in accordance with the Act, the regulations in this part, orders of the Director/Regional Director, and other applicable statutes, regulations, and amendments.

(a) This part does not apply to G&G exploration conducted by or on behalf of the lessee on a lease in the OCS. Refer to 30 CFR part 250 if you plan to conduct G&G activities related to oil, gas, or sulphur under terms of a lease.

(b) Federal agencies are exempt from the regulations in this part.

(c) G&G exploration or G&G scientific research related to minerals other than oil, gas, and sulphur is covered by regulations at 30 CFR part 580.

§ 551.4 Types of G&G activities that require permits or Notices.

(a) *Exploration*. You must have a BOEM-approved permit to conduct G&G exploration, including deep stratigraphic tests, for oil, gas, or sulphur resources. If you conduct both geological and geophysical exploration, you must have a separate permit for each.

(b) *Scientific research*. You may only conduct G&G scientific research related to oil, gas, and sulphur in the OCS after you obtain a BOEM-approved permit or file a Notice.

(1) *Permit*. You must obtain a permit if the research activities you propose to conduct involve:

(i) Using solid or liquid explosives;

(ii) Drilling a deep stratigraphic test; or

(iii) Developing data and information for proprietary use or sale.

(2) *Notice*. Any other G&G scientific research that you conduct related to oil, gas, and sulphur in the OCS requires you to file a Notice with the Regional Director at least 30 days before you begin. If circumstances preclude a 30-day Notice, you must provide oral notification and followup in writing. You must also inform BOEM in writing when you conclude your work.

§ 551.5 Applying for permits or filing Notices.

(a) *Permits*. You must submit a signed original and three copies of the BOEM permit application form (Form BOEM–0327). The form includes names of persons; the type, location, purpose, and dates of activity; and environmental and other information. A nonrefundable service fee of $2,012 must be paid electronically through *Pay.gov* at: *https://www.pay.gov/paygov/*, and you must include a copy of the *Pay.gov* confirmation receipt page with your application.

(b) *Disapproval of permit application*. If BOEM disapproves your application for a permit, the Regional Director will state the reasons for the denial and will advise you of the changes needed to obtain approval.

(c) *Notices*. You must sign and date a Notice and state:

(1) The name(s) of the person(s) who will conduct the proposed research;

(2) The name(s) of any other person(s) participating in the proposed research, including the sponsor;

(3) The type of research and a brief description of how you will conduct it;

(4) The location in the OCS, indicated on a map, plat, or chart, where you will conduct research;

(5) The proposed dates you project for your research activity to start and end;

(6) The name, registry number, registered owner, and port of registry of vessels used in the operation;

(7) The earliest practicable time you expect to make the data and information resulting from your research activity available to the public;

(8) Your plan of how you will make the data and information you collected available to the public;

(9) That you and others involved will not sell or withhold for exclusive use the data and information resulting from your research; and

(10) At your option, you may submit (as a substitute for the material required in paragraphs (c)(7), (c)(8), and (c)(9) of this section) the nonexclusive use agreement for scientific research attachment to Form BOEM–0327.

(d) *Filing locations*. You must apply for a permit or file a Notice at one of the following locations:

(1) For the OCS off the State of Alaska—the Regional Supervisor for Resource Evaluation, Bureau of Ocean Energy Management, Alaska OCS Region, 3801 Centerpoint Drive, Suite 500, Anchorage, Alaska 99503.

(2) For the OCS off the Atlantic Coast and in the Gulf of Mexico—the Regional Supervisor for Resource Evaluation, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123–2394.

(3) For the OCS off the coast of the States of California, Oregon, Washington, or Hawaii—the Regional Supervisor for Resource Evaluation, Bureau of Ocean Energy Management, Pacific OCS Region, 760 Paseo Camarillo, Suite 102 (CM 102), Camarillo, California 93010.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57096, Sept. 22, 2015]

§ 551.6 Obligations and rights under a permit or a Notice.

While conducting G&G exploration or scientific research activities under BOEM permit or Notice:

(a) You must not:

(1) Interfere with or endanger operations under any lease, right-of-way, easement, right-of-use, Notice, or permit issued or maintained under the Act;

(2) Cause harm or damage to life (including fish and other aquatic life), property, or to the marine, coastal, or human environment;

(3) Cause harm or damage to any mineral resource (in areas leased or not leased);

(4) Cause pollution;

(5) Disturb archaeological resources;

(6) Create hazardous or unsafe conditions; or

(7) Unreasonably interfere with or cause harm to other uses of the area.

(b) You must immediately report to the Regional Director if you:

(1) Detect hydrocarbon occurrences;

(2) Detect environmental hazards which imminently threaten life and property; or

(3) Adversely affect the environment, aquatic life, archaeological resources, or other uses of the area where you are conducting exploration or scientific research activities.

(c) You must also consult and coordinate your G&G activities with other users of the area for navigation and safety purposes.

(d) Any persons conducting shallow test drilling or deep stratigraphic test drilling activities under a permit must use the best available and safest technologies that the Regional Director determines to be economically feasible.

(e) You may not claim any oil, gas, sulphur, or other minerals you discover while conducting operations under a permit or Notice.

§ 551.7 Test drilling activities under a permit.

(a) *Shallow test drilling*. Before you begin shallow test drilling under a permit, the Regional Director may require you to:

(1) Gather and submit seismic, bathymetric, sidescan sonar, magnetometer, or other geophysical data and information to determine shallow structural detail across and in the vicinity of the proposed test.

(2) Submit information for coastal zone consistency certification according to paragraphs (b)(3) and (4) of this section, and for protecting archaeological resources according to paragraph (b)(5) of this section.

(3) Allow all interested parties the opportunity to participate in the shallow test according to paragraph (c) of this section, and meet bonding requirements according to paragraph (d) of this section.

(b) *Deep stratigraphic tests*. You must submit to the appropriate BOEM or BSEE Regional Director, at the address in § 551.7(d), a drilling plan (submitted to BOEM), an environmental report (submitted to BOEM), an Application for Permit to Drill (Form BSEE–0123) (submitted to BSEE), and a Supplemental APD Information Sheet (Form BSEE–0123S) (submitted to BSEE) as follows:

(1) *Drilling plan*. The drilling plan must include:

(i) The proposed type, sequence, and timetable of drilling activities;

(ii) A description of your drilling rig, indicating the important features with special attention to safety, pollution prevention, oil-spill containment and

cleanup plans, and onshore disposal procedures;

(iii) The location of each deep stratigraphic test you will conduct, including the location of the surface and projected bottomhole of the borehole;

(iv) The types of geological and geophysical survey instruments you will use before and during drilling;

(v) Seismic, bathymetric, sidescan sonar, magnetometer, or other geophysical data and information 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; and

(vi) Other relevant data and information that the BOEM Regional Director requires.

(2) *Environmental report.* The environmental report must include all of the following material:

(i) A summary with data and information available at the time you submitted the related drilling plan. BOEM will consider site-specific data and information developed since the most recent environmental impact statement or other environmental impact analysis in the immediate area. The summary must meet the following requirements:

(A) You must concentrate on the issues specific to the site(s) of drilling activity. However, you only need to summarize data and information discussed in any environmental reports, analyses, or impact statements prepared for the geographic area of the drilling activity.

(B) You must list referenced material. Include brief descriptions and a statement of where the material is available for inspection.

(C) You must refer only to data that are available to BOEM.

(ii) Details about your project such as:

(A) A list and description of new or unusual technologies;

(B) The location of travel routes for supplies and personnel;

(C) The kinds and approximate levels of energy sources;

(D) The environmental monitoring systems; and

(E) Suitable maps and diagrams showing details of the proposed project layout.

(iii) A description of the existing environment. For this section, you must include the following information on the area:

(A) Geology;

(B) Physical oceanography;

(C) Other uses of the area;

(D) Flora and fauna;

(E) Existing environmental monitoring systems; and

(F) Other unusual or unique characteristics that may affect or be affected by the drilling activities.

(iv) A description of the probable impacts of the proposed action on the environment and the measures you propose for mitigating these impacts.

(v) A description of any unavoidable or irreversible adverse effects on the environment that could occur.

(vi) Other relevant data that the BOEM Regional Director requires.

(3) *Copies for coastal States.* You must submit copies of the drilling plan and environmental report to the BOEM Regional Director for transmittal to the Governor of each affected coastal State and the coastal zone management agency of each affected coastal State that has an approved program under the Coastal Zone Management Act. (BOEM Regional Director will make the drilling plan and environmental report available to appropriate Federal agencies and the public according to the Department of the Interior's policies and procedures).

(4) *Certification of coastal zone management program consistency and State concurrence.* When required under an approved coastal zone management program of an affected State, your drilling plan must include a certification that the proposed activities described in the plan comply with enforceable policies of, and will be conducted in a manner consistent with such State's program. BOEM Regional Director may not approve any of the activities described in the drilling plan unless the State concurs with the consistency certification or the Secretary of Commerce makes the finding authorized by section 307(c)(3)(B)(iii) of the Coastal Zone Management Act.

(5) *Protecting archaeological resources.* If the Regional Director believes that an archaeological resource may exist in the area that may be affected by drilling, the Regional Director will notify you of the need to prepare an archaeological report.

(i) If the evidence suggests that an archaeological resource may be present, you must:

(A) Locate the site of the drilling so as to not adversely affect the area where the archaeological resources may be, or

(B) Establish to the satisfaction of the BOEM Regional Director that an archaeological resource does not exist or will not be adversely affected by drilling. This must 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 must be submitted to the BOEM Regional Director for review.

(ii) If the BOEM Regional Director determines that an archaeological resource is likely to be present in the area that may be affected by drilling, and may be adversely affected by drilling, the BOEM Regional Director will notify you immediately. You must take no action that may adversely affect the archaeological resource unless an investigation by BOEM determines that the resource is not archaeologically significant.

(iii) If you discover any archaeological resource while drilling, you must immediately halt drilling and report the discovery to the BOEM Regional Director. If investigations determine that the resource is significant, the BOEM Regional Director will inform you how to protect it.

(6) [Reserved]

(7) *Revising an approved drilling plan.* Before you revise an approved drilling plan, you must obtain the BOEM Regional Director's approval.

(8) [Reserved]

(9) *Deadline for completing a deep stratigraphic test.* If your deep stratigraphic test well is within 50 geographic miles of a tract that BOEM has identified for a future lease sale, as listed on the currently approved OCS leasing schedule, you must complete all drilling activities and submit the data and information to the BOEM Regional Director at least 60 days before the first day of the month in which BOEM schedules the lease sale. However, the BOEM Regional Director may extend your permit duration to allow you to complete drilling activities and submit data and information if the extension is in the National interest.

(c) *Group participation in test drilling.* BOEM encourages group participation for deep stratigraphic tests.

(1) *Purpose of group participation.* The purpose is to minimize duplicative G&G activities involving drilling into the seabed of the OCS.

(2) *Providing opportunity for participation in a deep stratigraphic test.* When you propose to drill a deep stratigraphic test, you must give all interested persons an opportunity to participate in the test drilling through a signed agreement on a cost-sharing basis. You may include a penalty for late participation of not more than 100 percent of the cost to each original participant in addition to the original share cost.

(i) The participants must assess and distribute late participation penalties in accordance with the terms of the agreement.

(ii) For a significant hydrocarbon occurrence that the Regional Director announces to the public, 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.

(3) *Providing opportunity for participation in a shallow test drilling project.* When you apply to conduct shallow test drilling activities, you must, if ordered by the Regional Director or required by the permit, give all interested persons an opportunity to participate in the test activity on a cost-sharing basis. You may include a penalty provision for late participation of not more than 50 percent of the cost to each original participant in addition to the original share cost.

(4) *Procedures for group participation in drilling activities.* You must:

(i) Publish a summary statement that describes the approved activity in a relevant trade publication;

(ii) Forward a copy of the published statement to the Regional Director;

(iii) Allow at least 30 days from the summary statement publication date for other persons to join as original participants;

(iv) Compute the estimated cost by dividing the estimated total cost of the program by the number of original participants; and

(v) Furnish the Regional Director with a complete list of all participants before starting operations, or at the end of the advertising period if you begin operations before the advertising period is over. The names of any subsequent or late participants must also be furnished to the Regional Director.

(5) *Changes to the original application for test drilling*. If you propose changes to the original application and the Regional Director determines that the changes are significant, the Regional Director will require you to publish the changes for an additional 30 days to give other persons a chance to join as original participants.

(d) *Bonding requirements*. You must submit a bond under this part before you may start a deep stratigraphic test.

(1) Before BOEM issues a permit authorizing the drilling of a deep stratigraphic test, you must either:

(i) Furnish to BOEM a bond of not less than $200,000 that guarantees compliance with all the terms and conditions of the permit; or

(ii) Maintain a $1 million bond that guarantees compliance with all the terms and conditions of the permit you hold for the OCS area where you propose to drill.

(2) You must provide additional security to BOEM if the Regional Director determines that it is necessary for the permit or area.

(3) 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.

(4) Your bond must be on a form approved by the Deputy Director.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57097, Sept. 22, 2015]

§ 551.8 Inspection and reporting requirements for activities under a permit.

(a) *Inspection of permit activities*. You must allow BOEM representatives to inspect your exploration or scientific research activities under a permit. They will determine whether operations are adversely affecting the environment, aquatic life, archaeological resources, or other uses of the area. BOEM will reimburse you for food, quarters, and transportation that you provide for BOEM representatives if you send in your reimbursement request to the Region that issued the permit within 90 days of the inspection.

(b) *Approval for modifications*. Before you begin modified operations, you must submit a written request describing the modifications and receive the Regional Director's oral or written approval. If circumstances preclude a written request, you must make an oral request and follow up in writing.

(c) *Reports*. (1) You must submit status reports on a schedule specified in the permit and include a daily log of operations.

(2) You must submit a final report of exploration or scientific research activities under a permit within 30 days after the completion of acquisition activities under the permit. You may combine the final report with the last status report and must include each of the following:

(i) A description of the work performed.

(ii) Charts, maps, plats, and digital navigational data in a format specified by the Regional Director, showing the areas and blocks in which any exploration or permitted scientific research activities were conducted. Identify the lines of geophysical traverses and their locations including a reference sufficient to identify the data produced during each activity.

(iii) The dates on which you conducted the actual exploration or scientific research activities.

(iv) A summary of any:

(A) Hydrocarbon or sulphur occurrences encountered;

(B) Environmental hazards; and

(C) Adverse effects of the exploration or scientific research activities on the

environment, aquatic life, archaeological resources, or other uses of the area in which the activities were conducted.

(v) Other descriptions of the activities conducted as specified by the Regional Director.

§ 551.9 Temporarily stopping, canceling, or relinquishing activities approved under a permit.

(a) BOEM may temporarily stop exploration or scientific research activities under a permit when the Regional Director determines that:

(1) Activities pose a threat of serious, irreparable, or immediate harm. This includes damage to life (including fish and other aquatic life), property, any mineral deposit (in areas leased or not leased), to the marine, coastal, or human environment, or to an archaeological resource;

(2) You failed to comply with any applicable law, regulation, order, or provision of the permit. This would include BOEM's required submission of reports, well records or logs, and G&G data and information within the time specified; or

(3) Stopping the activities is in the interest of National security or defense.

(b) *Procedures to temporarily stop activities.* (1) The Regional Director will advise you either orally or in writing. BOEM will confirm an oral notification in writing and deliver all written notifications by courier or certified or registered mail. You must halt all activities under a permit as soon as you receive an oral or written notification.

(2) The Regional Director will advise you when you may start your permit activities again.

(c) *Procedure to cancel or relinquish a permit.* The Regional Director may cancel, or a permittee may relinquish, a permit at any time.

(1) If BOEM cancels your permit, the Regional Director will advise you by certified or registered mail 30 days before the cancellation date and will state the reason.

(2) You may relinquish the permit by advising the Regional Director by certified or registered mail 30 days in advance.

(3) After BOEM cancels your permit or you relinquish it, you are still responsible for proper abandonment of any drill sites in accordance with the requirements of 30 CFR 251.7(b)(8). You must also comply with all other obligations specified in this part or in the permit.

§ 551.10 Penalties and appeals.

(a) *Penalties for noncompliance under a permit issued by BOEM.* You are subject to the penalty provisions of:

(1) Section 24 of the Act (43 U.S.C. 1350); and

(2) The procedures contained in 30 CFR part 550, subpart N, for noncompliance with:

(i) Any provision of the Act;

(ii) Any provision of a G&G or drilling permit; or

(iii) Any regulation or order issued under the Act.

(b) *Penalties under other laws and regulations.* The penalties prescribed in this section are in addition to any other penalty imposed by any other law or regulation.

(c) *Procedures to appeal orders or decisions BOEM issues.* See 30 CFR part 590 for instructions on how to appeal any order or decision that we issue under this part.

§ 551.11 Submission, inspection, and selection of geological data and information collected under a permit and processed by permittees or third parties.

(a) *Availability of geological data and information collected under a permit.* (1) You must notify the Regional Director, in writing, when you complete the initial analysis, processing, or interpretation of any geological data and information. Initial analysis and processing are the stages of analysis or processing where the data and information first become available for in-house interpretation by the permittee, or become available commercially to third parties via sale, trade, license agreement, or other means.

(2) The Regional Director may ask if you have further analyzed, processed, or interpreted any geological data and information. When so asked, you must respond to BOEM in writing within 30 days.

(b) *Submission, inspection, and selection of geological data and information.* The Regional Director may request the permittee or third party to submit the analyzed, processed, and interpreted geologic data and information for inspection and/or permanent retention by BOEM. The data and information must be submitted within 30 days after such request.

(c) *Requirements for submission of geological data and information collected under a permit.* Unless the Regional Director specifies otherwise, geological data and information must include:

(1) An accurate and complete record of all geological (including geochemical) data and information describing each operation of analysis, processing, and interpretation;

(2) Paleontological reports identifying microscopic fossils by depth, including the reference datum to which paleontological sample depths are related and, if the Regional Director requests, washed samples that you maintain for paleontological determinations;

(3) Copies of well logs or charts in a digital format, if available;

(4) Results and data obtained from formation fluid tests;

(5) Analyses of core or bottom samples and/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) Other geological data and information that the Regional Director may specify.

(d) *Obligations when geological data and information collected under permit are obtained by a third party.* A third party may obtain geological data and information from a permittee, or from another third party, by sale, trade, license agreement, or other means. If this happens:

(1) The third party recipient of the data and information assumes the obligations under this section, except for the notification provisions of paragraph (a)(1), and is subject to the penalty provisions of 30 CFR part 550, subpart N; and

(2) A permittee or third party that sells, trades, licenses, or otherwise provides data and information to a third party must advise the recipient, in writing, that accepting these obligations is a condition precedent of the sale, trade, license, or other agreement; and

(3) Except for license agreements, a permittee or third party that sells, trades, or otherwise provides data and information to a third party must advise the Regional Director, in writing and within 30 days, of the sale, trade, or other agreement, including the identity of the recipient of the data and information; or

(4) For license agreements a permittee or third party that licenses data and information to a third party must, within 30 days of a request by the Regional Director, advise the Regional Director, in writing, of the license agreement, including the identity of the recipient of the data and information.

§ 551.12 Submission, inspection, and selection of geophysical data and information collected under a permit and processed by permittees or third parties.

(a) *Availability of geophysical data and information collected under a permit.* (1) You must notify the Regional Director, in writing, when you complete the initial processing and interpretation of any geophysical data and information. Initial processing is the stage of processing where the data and information become available for in-house interpretation by the permittee, or become available commercially to third parties via sale, trade, license agreement, or other means.

(2) The Regional Director may ask if you have further processed or interpreted any geophysical data and information. When so asked, you must respond to BOEM in writing within 30 days.

(b) *Submission, inspection and selection of geophysical data and information collected under a permit.* The Regional Director may request that the permittee or third party submit geophysical data and information before making a final selection for retention. BOEM representatives may inspect and select the data and information on your premises,

or the Regional Director can request delivery of the data and information to the appropriate BOEM regional office for review.

(1) You must submit the geophysical data and information within 30 days of receiving the request, unless the Regional Director extends the delivery time.

(2) At any time before final selection, the Regional Director may return any or all geophysical data and information following review. You will be notified in writing of all or portions of those data the Regional Director decides to retain.

(c) *Requirements for submission of geophysical data and information collected under a permit.* Unless the Regional Director specifies otherwise, you must include:

(1) An accurate and complete record of each geophysical survey conducted under the permit, including digital navigational data and final location maps;

(2) All seismic data collected 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 quality format suitable for interpretive evaluation, reflecting state-of-the-art processing techniques; and

(4) Other geophysical data, processed geophysical information, and interpreted geophysical information including, 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.

(d) *Obligations when geophysical data and information collected under a permit are obtained by a third party.* A third party may obtain geophysical data, processed geophysical information, or interpreted geophysical information from a permittee, or from another third party, by sale, trade, license agreement, or other means. If this happens:

(1) The third party recipient of the data and information assumes the obligations under this section, except for the notification provisions of paragraph (a)(1), and is subject to the penalty provisions of 30 CFR part 550, subpart N; and

(2) A permittee or third party that sells, trades, licenses, or otherwise provides data and information to a third party must advise the recipient, in writing, that accepting these obligations is a condition precedent of the sale, trade, license, or other agreement; and

(3) Except for license agreements, a permittee or third party that sells, trades, or otherwise provides data and information to a third party must advise the Regional Director, in writing and within 30 days, of the sale, trade, or other agreement, including the identity of the recipient of the data and information; or

(4) For license agreements, a permittee or third party that licenses data and information to a third party must, within 30 days of a request by the Regional Director, advise the Regional Director, in writing, of the license agreement, including the identity of the recipient of the data and information.

§ 551.13 Reimbursement for the costs of reproducing data and information and certain processing costs.

(a) BOEM will reimburse you or a third party for reasonable costs of reproducing data and information that the Regional Director requests if:

(1) You deliver G&G data and information to BOEM for the Regional Director to inspect or select and retain (according to § 551.11 or § 551.12);

(2) BOEM receives your request for reimbursement and the Regional Director determines that the requested reimbursement is proper; and

(3) The cost is at your lowest rate (or a third party's) or at the lowest commercial rate established in the area, whichever is less.

(b) BOEM will reimburse you or the third party for the reasonable costs of processing geophysical information (which does not include cost of data acquisition):

(1) If, at the request of the Regional Director, you processed the geophysical data or information in a form or manner other than that used in the normal conduct of business; or

(2) If you collected the information under a permit that BOEM issued to you before October 1, 1985, and the Regional Director requests and retains the information.

(c) When you request reimbursement, you must identify reproduction and processing costs separately from acquisition costs.

(d) BOEM will not reimburse you or a third party for data acquisition costs or for the costs of analyzing or processing geological information or interpreting geological or geophysical information.

§ 551.14 Protecting and disclosing data and information submitted to BOEM under a permit.

(a) *Disclosure of data and information to the public by BOEM.* (1) In making data and information available to the public, the Regional Director will follow the applicable requirements of:

(i) The Freedom of Information Act (5 U.S.C. 552);

(ii) The implementing regulations at 43 CFR part 2;

(iii) The Act; and

(iv) The regulations at 30 CFR parts 550 and 552.

(2) Except as specified in this section or in 30 CFR parts 550 and 552, if the Regional Director determines any data or information is exempt from public disclosure under this paragraph (a), BOEM will not provide the data and information to any State or to the executive of any local government or to the public, unless you and all third parties agree to the disclosure.

(3) BOEM will keep confidential the identity of third party recipients of data and information collected under a permit. BOEM will not release the identity unless you and the third parties agree to the disclosure.

(4) When you detect any significant hydrocarbon occurrences or environmental hazards on unleased lands during drilling operations, the Regional Director will immediately issue a public announcement. The announcement must further the National interest, but without unduly damaging your competitive position.

(b) *Timetable for release of G&G data and information related to oil, gas, and sulphur that BOEM acquires.* Except for high-resolution data and information released under 30 CFR 550.197(b)(2), BOEM will release or disclose acquired data and information in accordance with paragraphs (b)(1) through (7) of this section.

(1) If the data and information are not related to a deep stratigraphic test, BOEM will release them to the public in accordance with the following table:

If you or a third party submit and BOEM retains . . .	The Regional Director will release them to the public . . .
(i) Geological data and information,	10 years after BOEM issued the permit.
(ii) Geophysical data,	50 years after BOEM issued the permit.
(iii) Geophysical information processed or reprocessed less than 20 years after BOEM issued the germane permit,	25 years after BOEM issued the permit.
(iv) Geophysical information processed or reprocessed 20 or more years after BOEM issued the germane permit,	25 years after BOEM issued the permit; or, if you or a third party applied for an extension of the proprietary term, 5 years after BOEM approved the application for an extension. In any case BOEM will release the information no later than 50 years after BOEM issued the permit.

(2) Permittees and third parties may apply to BOEM for an extension of the 25-year proprietary term for geophysical information reprocessed 20 or more years after BOEM issued the germane permit. You must submit the application to BOEM within 90 days after completion of the reprocessing, except during the initial 1-year grace period as provided in paragraph (b)(5) below. Filing locations are listed in § 551.5(d). Your application must include:

(i) Name and address of the permittee or third party;

(ii) Product name;

(iii) Identification of the geophysical information area;

(iv) Identification of originating permit number and date;

(v) Description of reprocessing performed;

(vi) Identification of the date of completion of reprocessing the geophysical information;

(vii) Certification that the product meets the definition of processed geophysical information and that all other information in the application is accurate; and

(viii) Signature and date.

(3) With each new reprocessing of permitted data, you may apply for an extension of up to 5 years. However, the maximum proprietary term for geophysical information is 50 years after the permit was issued. Once the maximum term is reached, the BOEM Regional Director will release the information to the public.

(4) Geophysical information processed or reprocessed 20 or more years after the germane permit was issued and granted the extension will be subject to submission, inspection, and selection criteria under § 551.12 and reimbursement criteria identified under § 551.13.

(5) There was a 1-year grace period, that started September 14, 2009, that allowed permittees and third parties sufficient time to meet the above requirements and apply for all eligible extensions. During that time, BOEM did not release geophysical information which was reprocessed 20 or more years after the date that the germane permit was issued.

(6) Since September 14, 2010, BOEM has resumed releasing eligible reprocessed information. If an application for extension was not filed, not filed on time, or not approved by BOEM, the original 25-year proprietary term applies to the release date of the reprocessed geophysical information.

(7) If the data and information are related to a deep stratigraphic test, BOEM will release them to the public at the earlier of the following times:

(i) Twenty-five years after you complete the test; or

(ii) If a lease sale is held after you complete a test well, 60-calendar days after BOEM issues the first lease, any portion of which is located within 50 geographic miles (92.7 kilometers) of the test.

(8) BOEM may allow limited inspection, but only by persons with a direct interest in related BOEM decisions and issues in specific geographic areas, and who agree in writing to its confidentiality, of G&G data and information submitted under this part that BOEM uses to:

(i) Make unitization determinations on two or more leases;

(ii) Make competitive reservoir determinations;

(iii) Ensure proper plans of development for competitive reservoirs;

(iv) Promote operational safety;

(v) Protect the environment;

(vi) Make field determinations; or

(vii) Determine eligibility for royalty relief.

(c) *Procedure that BOEM follows to disclose acquired data and information to a contractor for reproduction, processing, and interpretation.* (1) When practical, the Regional Director will advise the person who submitted data and information under § 551.11 or § 551.12 of the intent to disclose the data or information to an independent contractor or agent.

(2) The person so notified will have at least 5 working days to comment on the action.

(3) When the Regional Director advises the person who submitted the data and information, all other owners of the data or information will be considered to have been so notified.

(4) Before disclosure, the contractor or agent must sign a written commitment not to sell, trade, license, or disclose data or information to anyone without the Regional Director's consent.

(d) *Sharing data and information with coastal States.* (1) When BOEM solicits nominations for leasing lands located within 3 geographic miles (5.6 kilometers) of the seaward boundary of any coastal State, the Regional Director, in accordance with 30 CFR 552.7(a)(4) and (b) and subsections 8(g) and 26(e) of the Act (43 U.S.C. 1337(g) and 1352(e)), will provide the Governor with:

(i) All information on the geographical, geological, and ecological characteristics of the areas and regions BOEM proposes to offer for lease;

(ii) An estimate of the oil and gas reserves in the areas proposed for leasing; and

(iii) An identification of any field, geological structure, or trap on the OCS within 3 geographic miles (5.6 kilometers) of the seaward boundary of the State.

(2) After receiving nominations for leasing an area of the OCS within 3 geographic miles of the seaward boundary of any coastal State, BOEM will carry out a tentative area identification according to 30 CFR part 556, subparts D and E. At that time, the Regional Director will consult with the Governor to determine whether any tracts further considered for leasing may contain any oil or gas reservoirs that underlie both the OCS and lands subject to the jurisdiction of the State.

(3) Before a sale, if a Governor requests, the Regional Director, in accordance with 30 CFR 552.7(a)(4) and (b) and sections 8(g) and 26(e) of the Act (43 U.S.C. 1337(g) and 1352(e)), will share with the Governor information that identifies potential and/or proven common hydrocarbon bearing areas within 3 geographic miles of the seaward boundary of that State.

(4) Information received and knowledge gained by a State official under paragraph (d) of this section is subject to applicable confidentiality requirements of:

(i) The Act; and

(ii) The regulations at 30 CFR parts 550, 551, and 552.

§ 551.15 Authority for information collection.

(a) The Office of Management and Budget has approved the information collection requirements in this part under 44 U.S.C. 3501 *et seq.* and assigned OMB control number 1010–0048. The title of this information collection is ''30 CFR part 551, Geological and Geophysical (G&G) Explorations of the OCS.''

(b) We 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) We use the information collected under this part to:

(1) Evaluate permit applications and monitor scientific research activities for environmental and safety reasons.

(2) Determine that explorations do not harm resources, result in pollution, create hazardous or unsafe conditions, or interfere with other users in the area.

(3) Approve reimbursement of certain expenses.

(4) Monitor the progress and activities carried out under an OCS G&G permit.

(5) Inspect and select G&G data and information collected under an OCS G&G permit.

(d) Respondents are Federal OCS permittees and Notice filers. Responses are mandatory or are required to obtain or retain a benefit. We will protect information considered proprietary under applicable law and under regulations at § 551.14 and part 550 of this chapter.

(e) 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, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57097, Sept. 22, 2015]

PART 552—OUTER CONTINENTAL SHELF (OCS) OIL AND GAS INFORMATION PROGRAM

Sec.

552.1 Purpose.
552.2 Definitions.
552.3 Oil and gas data and information to be provided for use in the OCS Oil and Gas Information Program.
552.4 Summary Report to affected States.
552.5 Information to be made available to affected States.
552.6 Freedom of Information Act requirements.
552.7 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: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

§ 552.1 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 30 CFR parts 250, 251, 550,

and 551 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, Bureau of Ocean Energy Management. 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.

§ 552.2 Definitions.

When used in the regulations in this part, the following terms shall have the meanings given below:

Act refers to the Outer Continental Shelf Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

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.

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.

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.

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.

Data means facts and statistics or samples which have not been analyzed or processed.

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.

Director means the Director of the Bureau of Ocean Energy Management of the U.S. Department of the Interior or a designee of the Director.

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.

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.

Information, when used without a qualifying adjective, includes analyzed 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, oil or natural gas, or the land covered by such authorization, whichever is required by the context.

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 550 of this chapter, including all parties holding such authority by or through the lessee.

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.

Permittee means the party authorized by a permit issued pursuant to part 551 of this chapter to conduct activities on the OCS.

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.

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.

Secretary means the Secretary of the Interior or a designee of the Secretary.

§ 552.3 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 BOEM 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.

§ 552.4 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 BOEM 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.

§ 552.5 Information to be made available to affected States.

(a) The Director shall prepare an index of OCS information (see 30 CFR 556.10). 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 BOEM, 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.

§ 552.6 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 parts 250 and 550 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf) and 30

CFR part 551 (Geological and Geophysical Explorations of the Outer Continental Shelf).

(b) Except as provided in § 552.7 or in 30 CFR parts 250, 251, 550, and 551 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.

§ 552.7 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 250.197, 550.197, and 551.14, 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 250.197, 550.197, and 551.14, 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) of this section 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 parts 250 and 550 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf), the regulations contained in 30 CFR parts 251 and 551 (Geological and Geophysical Explorations of the Outer Continental Shelf), and the regulations contained in 30 CFR parts 252 and 552 (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 553—OIL SPILL FINANCIAL RESPONSIBILITY FOR OFFSHORE FACILITIES

Subpart A—General

Sec.
553.1 What is the purpose of this part?
553.3 How are the terms used in this regulation defined?
553.5 What is the authority for collecting Oil Spill Financial Responsibility (OSFR) information?

Subpart B—Applicability and Amount of OSFR

553.10 What facilities does this part cover?
553.11 Who must demonstrate OSFR?
553.12 May I ask BOEM for a determination of whether I must demonstrate OSFR?
553.13 How much OSFR must I demonstrate?
553.14 How do I determine the worst case oil-spill discharge volume?
553.15 What are my general OSFR compliance responsibilities?

Subpart C—Methods for Demonstrating OSFR

553.20 What methods may I use to demonstrate OSFR?
553.21 How can I use self-insurance as OSFR evidence?
553.22 How do I apply to use self-insurance as OSFR evidence?
553.23 What information must I submit to support my net worth demonstration?
553.24 When I submit audited annual financial statements to verify my net worth, what standards must they meet?
553.25 What financial test procedures must I use to determine the amount of self-insurance allowed as OSFR evidence based on net worth?
553.26 What information must I submit to support my unencumbered assets demonstration?
553.27 When I submit audited annual financial statements to verify my unencumbered assets, what standards must they meet?
553.28 What financial test procedures must I use to evaluate the amount of self-insurance allowed as OSFR evidence based on unencumbered assets?
553.29 How can I use insurance as OSFR evidence?
553.30 How can I use an indemnity as OSFR evidence?
553.31 How can I use a surety bond as OSFR evidence?
553.32 Are there alternative methods to demonstrate OSFR?

Subpart D—Requirements for Submitting OSFR Information

553.40 What OSFR evidence must I submit to BOEM?
553.41 What terms must I include in my OSFR evidence?
553.42 How can I amend my list of COFs?
553.43 When is my OSFR demonstration or the amendment to my OSFR demonstration effective?
553.44 [Reserved]
553.45 Where do I send my OSFR evidence?

Subpart E—Revocation and Penalties

553.50 How can BOEM refuse or invalidate my OSFR evidence?
553.51 What are the penalties for not complying with this part?

Subpart F—Claims for Oil-Spill Removal Costs and Damages

553.60 To whom may I present a claim?
553.61 When is a guarantor subject to direct action for claims?
553.62 What are the designated applicant's notification obligations regarding a claim?

Subpart G—Limit of Liability for Offshore Facilities

553.700 What is the scope of this subpart?
553.701 To which entities does this subpart apply?

553.702 What limit of liability applies to my offshore facility?
553.703 What is the procedure for calculating the limit of liability adjustment for inflation?
553.704 How will BOEM publish the offshore facility limit of liability adjustment?
APPENDIX TO PART 553—LIST OF U.S. GEOLOGICAL SURVEY TOPOGRAPHIC MAPS

AUTHORITY: 33 U.S.C. 2704, 2716, as amended.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General

§ 553.1 What is the purpose of this part?

This part establishes the requirements for demonstrating Oil Spill Financial Responsibility for covered offshore facilities (COF), sets forth the procedures for claims against COF guarantors, and sets forth the limit of liability for offshore facilities, as adjusted, un der Title I of the Oil Pollution Act of 1990, as amended, 33 U.S.C. 2701 *et seq*. (OPA).

[79 FR 73839, Dec. 12, 2014]

§ 553.3 How are the terms used in this regulation defined?

Terms used in this part have the following meaning:

Advertise means publication of the notice of designation of the source of the incident and the procedures by which the claims may be presented, according to 33 CFR part 136, subpart D.

Annual CPI–U means the annual ''Consumer Price Index-All Urban Consumers, Not Seasonally Adjusted, U.S. City Average, All items, 1982 – 84 = 100,'' published by the U.S. Department of Labor, Bureau of Labor Statistics.

Bay means a body of water included in the Geographic Names Information System (GNIS) bay feature class. A GNIS bay includes an arm, bay, bight, cove, estuary, gulf, inlet, or sound.

Claim means a written request, for a specific sum, for compensation for damages or removal costs resulting from an oil-spill discharge or a substantial threat of the discharge of oil.

Claimant means any person or government who presents a claim for compensation under OPA.

Coastline means the line of ordinary low water along that portion of the coast that is in direct contact with the open sea which marks the seaward limit of inland waters.

Covered offshore facility (COF) means a facility:

(1) That includes any structure and all its components (including wells completed at the structure and the associated pipelines), equipment, pipeline, or device (other than a vessel or other than a pipeline or deepwater port licensed under the Deepwater Port Act of 1974 (33 U.S.C. 1501 *et seq*.)) used for exploring for, drilling for, or producing oil or for transporting oil from such facilities. This includes a well drilled from a mobile offshore drilling unit (MODU) and the associated riser and well control equipment from the moment a drill shaft or other device first touches the seabed for purposes of exploring for, drilling for, or producing oil, but it does not include the MODU; and

(2) That is located:

(i) Seaward of the coastline; or

(ii) In any portion of a bay that is:

(A) Connected to the sea, either directly or through one or more other bays; and

(B) Depicted in whole or in part on any USGS map listed in the Appendix to this part, or on any map published by the USGS that is a successor to and covers all or part of the same area as a listed map. Where any portion of a bay is included on a listed map, this rule applies to the entire bay; and

(3) That has a worst case oil-spill discharge potential of more than 1,000 bbls of oil, or a lesser volume if the Director determines in writing that the oil-spill discharge risk justifies the requirement to demonstrate OSFR.

Current period means the year in which the Annual CPI–U was most recently published by the U.S. Department of Labor, Bureau of Labor Statistics.

Designated applicant means a person the responsible parties designate to demonstrate OSFR for a COF on a lease, permit, or right-of-use and easement.

Director means the Director of the Bureau of Ocean Energy Management.

Fund means the Oil Spill Liability Trust Fund established by section 9509 of the Internal Revenue Code of 1986 as amended (26 U.S.C. 9509).

Geographic Names Information System (GNIS) means the database developed by the USGS in cooperation with the U.S. Board of Geographic Names which contains the federally-recognized geographic names for all known places, features, and areas in the United States that are identified by a proper name. Each feature is located by state, county, and geographic coordinates and is referenced to the appropriate 1:24,000-scale or 1:63,360-scale USGS topographic map on which it is shown.

Guarantor means a person other than a responsible party who provides OSFR evidence for a designated applicant.

Guaranty means any acceptable form of OSFR evidence provided by a guarantor including an indemnity, insurance, or surety bond.

Incident means any occurrence or series of occurrences having the same origin that results in the discharge or substantial threat of the discharge of oil.

Indemnity means an agreement to indemnify a designated applicant upon its satisfaction of a claim.

Indemnitor means a person providing an indemnity for a designated applicant.

Independent accountant means a certified public accountant who is certified by a state, or a chartered accountant certified by the government of jurisdiction within the country of incorporation of the company proposing to use one of the self-insurance evidence methods specified in this subpart.

Insolvent has the meaning set forth in 11 U.S.C. 101, and generally refers to a financial condition in which the sum of a person's debts is greater than the value of the person's assets.

Lease means any form of authorization issued under the Outer Continental Shelf Lands Act or state law which allows oil and gas exploration and production in the area covered by the authorization.

Lessee means a person holding a leasehold interest in an oil or gas lease including an owner of record title or a holder of operating rights (working interest owner).

Oil means oil of any kind or in any form, except as excluded by paragraph (2) of this definition.

(1) Oil includes:

(i) Petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil;

(ii) Hydrocarbons produced at the wellhead in liquid form;

(iii) Gas condensate that has been separated from gas before pipeline injection.

(2) Oil does not include petroleum, including crude oil or any fraction thereof, which is specifically listed or designated as a hazardous substance under subparagraphs (A) through (F) of section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (42 U.S.C. 9601).

Oil Spill Financial Responsibility (OSFR) means the capability and means by which a responsible party for a covered offshore facility will meet removal costs and damages for which it is liable under Title I of the Oil Pollution Act of 1990, as amended (33 CFR 2701 *et seq.*), with respect to both oil-spill discharges and substantial threats of the discharge of oil.

Outer Continental Shelf (OCS) has the same meaning as the term ''Outer Continental Shelf'' defined in section 2(a) of the OCS Lands Act (OCSLA) (43 U.S.C. 1331(a)).

Permit means an authorization, license, or permit for geological exploration issued under section 11 of the OCSLA (43 U.S.C. 1340) or applicable state law.

Person means an individual, corporation, partnership, association (including a trust or limited liability company), state, municipality, commission or political subdivision of a state, or any interstate body.

Pipeline means the pipeline segments and any associated equipment or appurtenances used or intended for use in the transportation of oil or natural gas.

Previous period means the year in which the previous limit of liability was established, or last adjusted by statute or regulation, whichever is later.

Responsible party, for purposes of subparts B through F, has the following meanings:

(1) For a COF that is a pipeline, responsible party means any person owning or operating the pipeline;

(2) For a COF that is not a pipeline, responsible party means either the lessee or permittee of the area in which the COF is located, or the holder of a right-of-use and easement granted under applicable State law or the OCSLA (43 U.S.C. 1301–1356) for the area in which the COF is located (if the holder is a different person than the lessee or permittee). A Federal agency, State, municipality, commission, or political subdivision of a State, or any interstate body that as owner transfers possession and right to use the property to another person by lease, assignment, or permit is not a responsible party; and

(3) For an abandoned COF, responsible party means any person who would have been a responsible party for the COF immediately before abandonment.

Responsible party, for purposes of subpart G, has the meaning in 33 U.S.C. 2701(32)(C), (E) and (F). This definition includes, as applicable, lessees as defined in this subpart, permittees, right-of-use and easement holders, and pipeline owners and operators.

Right-of-use and easement (RUE) means any authorization to use the OCS or submerged land for purposes other than those authorized by a lease or permit, as defined herein. It includes pipeline rights-of-way.

Source of the incident means the facility from which oil was discharged or which poses a substantial threat of discharging oil, as designated by the Director, National Pollution Funds Center, according to 33 CFR part 136, subpart D.

State means the several States of the United States, the District of Columbia, the Commonwealth of Puerto Rico, Guam, American Samoa, the United States Virgin Islands, the Commonwealth of the Northern Marianas, and any other territory or possession of the United States.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 73839, Dec. 12, 2014]

§ 553.5 What is the authority for collecting Oil Spill Financial Responsibility (OSFR) information?

(a) The Office of Management and Budget (OMB) has approved the information collection requirements in this part 553 under 44 U.S.C. 3501 *et seq.*, and assigned OMB control number 1010–0106.

(b) BOEM collects the information to ensure that the designated applicant for a COF has the financial resources necessary to pay for cleanup and damages that could be caused by oil discharges from the COF. BOEM uses the information to ensure compliance of offshore lessees, owners, and operators of covered facilities with OPA; to establish eligibility of designated applicants for OSFR certification (OSFRC); and to establish a reference source of names, addresses, and telephone numbers of responsible parties for covered facilities and their designated agents, guarantors, and U.S. agents for service of process for claims associated with oil pollution from designated covered facilities. The requirement to provide the information is mandatory. No information submitted for OSFRC is confidential or proprietary.

(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, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57097, Sept. 22, 2015]

Subpart B—Applicability and Amount of OSFR

§ 553.10 What facilities does this part cover?

(a) This part applies to any COF on any lease or permit issued or on any RUE granted under the OCSLA or applicable State law.

(b) For a pipeline COF that extends onto land, this part applies to that portion of the pipeline lying seaward of the first accessible flow shut-off device on land.

§ 553.11 Who must demonstrate OSFR?

(a) A designated applicant must demonstrate OSFR. A designated applicant may be a responsible party or another person authorized under this section. Each COF must have a single designated applicant.

(1) If there is more than one responsible party, those responsible parties must use Form BOEM–1017 to select a designated applicant. The designated applicant must submit Form BOEM–1016 and agree to demonstrate OSFR on behalf of all the responsible parties.

(2) If you are a designated applicant who is not a responsible party, you must agree to be liable for claims made under OPA jointly and severally with the responsible parties.

(b) The designated applicant for a COF on a lease must be either:

(1) A lessee; or

(2) The designated operator for the OCS lease under 30 CFR 550.143 or the unit operator designated under a Federally approved unit including the OCS lease. For a lease or unit not in the OCS, the operator designated under the lease or unit operating agreement for the lease may be the designated applicant only if the operator has agreed to be responsible for compliance with all the laws and regulations applicable to the lease or unit.

(c) The designated applicant for a COF on a permit must be the permittee.

(d) The designated applicant for a COF on a RUE must be the holder of the RUE or, if there is a pipeline on the RUE, the owner or operator of the pipeline.

(e) BOEM may require the designated applicant for a lease, permit, or RUE to be a person other than a person identified in paragraphs (b) through (d) of this section if BOEM determines that a person identified in paragraphs (b) through (d) cannot adequately demonstrate OSFR.

(f) If you are a responsible party and you fail to designate an applicant, then you must demonstrate OSFR under the requirements of this part.

§ 553.12 May I ask BOEM for a determination of whether I must demonstrate OSFR?

You may submit to BOEM a request for a determination of OSFR applicability. Address the request to the office identified in § 553.45. You must include in your request any information that will assist BOEM in making the determination. BOEM may require you to submit other information before making a determination of OSFR applicability.

§ 553.13 How much OSFR must I demonstrate?

(a) The following general parameters apply to the amount of OSFR that you must demonstrate:

If you are the designated applicant for . . .	Then you must demonstrate . . .
Only one COF,	The amount of OSFR that applies to the COF.
More than one COF,	The highest amount of OSFR that applies to any one of the COFs.

(b) You must demonstrate OSFR in the amounts specified in this section:

(1) For a COF located wholly or partially in the OCS you must demonstrate OSFR in accordance with the following table:

COF worst case oil-spill discharge volume	Applicable amount of OSFR
Over 1,000 bbls but not more than 35,000 bbls	$35,000,000
Over 35,000 but not more than 70,000 bbls	70,000,000
Over 70,000 but not more than 105,000 bbls	105,000,000
Over 105,000 bbls	150,000,000

(2) For a COF not located in the OCS you must demonstrate OSFR in accordance with the following table:

COF worst case oil-spill discharge volume	Applicable amount of OSFR
Over 1,000 bbls but not more than 10,000 bbls	$10,000,000
Over 10,000 but not more than 35,000 bbls	35,000,000
Over 35,000 but not more than 70,000 bbls	70,000,000
Over 70,000 but not more than 105,000 bbls	105,000,000
Over 105,000 bbls	150,000,000

(3) The Director may determine that you must demonstrate an amount of OSFR greater than the amount in paragraphs (b)(1) and (2) of this section based on the relative operational, environmental, human health, and other risks that your COF poses. The Director may require an amount that is one or more levels higher than the amount indicated in paragraph (b)(1) or (2) of this section for your COF. The Director will not require an OSFR demonstration that exceeds $150 million.

(4) You must demonstrate OSFR in the lowest amount specified in the applicable table in paragraph (b)(1) or (2) of this section for a facility with a potential worst case oil-spill discharge of 1,000 bbls or less if the Director notifies you in writing that the demonstration is justified by the risks of the potential oil-spill discharge.

§ 553.14 How do I determine the worst case oil-spill discharge volume?

(a) To calculate the amount of OSFR you must demonstrate for a facility under § 553.13(b), you must use the worst case oil-spill discharge volume that you determined under whichever of the following regulations applies:

(1) 30 CFR part 254—Response Plans for Facilities Located Seaward of the Coast Line, except that the volume of the worst case oil-spill discharge for a well must be four times the uncontrolled flow volume that you estimate for the first 24 hours.

(2) 40 CFR part 112—Oil Pollution Prevention; or

(3) 49 CFR part 194—Response Plans for Onshore Oil Pipelines.

(b) If you are a designated applicant and you choose to demonstrate $150 million in OSFR, you are not required to determine any worst case oil-spill discharge volumes, since that is the maximum amount of OSFR required under this part.

§ 553.15 What are my general OSFR compliance responsibilities?

(a) You must maintain continuous OSFR coverage for all your leases, permits, and RUEs with COFs for which you are the designated applicant.

(b) You must ensure that new OSFR evidence is submitted before your current evidence lapses or is canceled and that coverage for your new COF is submitted before the COF goes into operation.

(c) If you use self-insurance to demonstrate OSFR and find that you no longer qualify to self-insure the required OSFR amount based upon your latest audited annual financial statements, then you must demonstrate OSFR using other methods acceptable to BOEM by whichever of the following dates comes first:

(1) Sixty calendar days after you receive your latest audited annual financial statement; or

(2) The first calendar day of the 5th month after the close of your fiscal year.

(d) You may use a surety bond to demonstrate OSFR. If you find that your bonding company has lost its state license or has had its U.S. Treasury Department certification revoked, then you must replace the surety bond within 15 calendar days using a method of OSFR that is acceptable to BOEM.

(e) You must notify BOEM in writing within 15 calendar days after a change occurs that would prevent you from meeting your OSFR obligations (e.g., if you or your indemnitor petition for bankruptcy under chapters 7 or 11 of Title 11, U.S.C.). You must take any

action BOEM directs to ensure an acceptable OSFR demonstration.

(f) If you deny payment of a claim presented to you under § 553.60, then you must give the claimant a written explanation for your denial.

Subpart C—Methods for Demonstrating OSFR

§ 553.20 What methods may I use to demonstrate OSFR?

As the designated applicant, you may satisfy your OSFR requirements by using one or a combination of the following methods to demonstrate OSFR:

(a) Self-insurance under §§ 553.21 through 553.28;

(b) Insurance under § 553.29;

(c) An indemnity under § 553.30;

(d) A surety bond under § 553.31; or

(e) An alternative method the Director approves under § 553.32.

§ 553.21 How can I use self-insurance as OSFR evidence?

(a) If you use self-insurance to satisfy all or part of your obligation to demonstrate OSFR, you must annually pass either a net worth test under § 553.25 or an unencumbered net asset test under § 553.28.

(b) To establish the amount of self-insurance allowed, you must submit evidence of your net worth under § 553.23 or evidence of your unencumbered assets under § 553.26.

(c) You must identify a U.S. agent for service of process.

§ 553.22 How do I apply to use self-insurance as OSFR evidence?

(a) You must submit a complete Form BOEM–1018 with each application to demonstrate OSFR using self-insurance.

(b) You must submit your application to renew OSFR using self-insurance by the first calendar day of the 5th month after the close of your fiscal year. You may submit to BOEM your initial application to demonstrate OSFR using self-insurance at any time.

§ 553.23 What information must I submit to support my net worth demonstration?

You must support your net worth evaluation with information contained in your previous fiscal year's audited annual financial statement.

(a) Audited annual financial statements must be in the form of:

(1) An annual report, prepared in accordance with the generally accepted accounting practices (GAAP) of the United States or other international accounting practices determined to be equivalent by BOEM; or

(2) A Form 10–K or Form 20–F, prepared in accordance with Securities and Exchange Commission regulations.

(b) Audited annual financial statements must be submitted together with a letter signed by your treasurer highlighting:

(1) The State or the country of incorporation;

(2) The total amount of the stockholders' equity as shown on the balance sheet;

(3) The net amount of the plant, property, and equipment shown on the balance sheet; and

(4) The net amount of the identifiable U.S. assets and the identifiable total assets in the auditor's notes to the financial statement (*i.e.*, a geographic segmented business note).

§ 553.24 When I submit audited annual financial statements to verify my net worth, what standards must they meet?

(a) Your audited annual financial statements must be bound.

(b) Your audited annual financial statements must include the unqualified opinion of an independent accountant that states:

(1) The financial statements are free from material misstatement, and

(2) The audit was conducted in accordance with the generally accepted auditing standards (GAAS) of the United States, or other international auditing standards that BOEM determines to be equivalent.

(c) The financial information you submit must be expressed in U.S. dollars. If this information was originally reported in another form of currency, you must convert it to U.S. dollars using the conversion factor that was effective on the last day of the fiscal year pertinent to your financial statements. You also must identify the source of the currency exchange rate.

§ 553.25 What financial test procedures must I use to determine the amount of self-insurance allowed as OSFR evidence based on net worth?

(a) Divide the total amount of the stockholders'/owners' equity listed on the balance sheet by ten.

(b) Divide the net amount of the identifiable U.S. assets by the net amount of the identifiable total assets.

(c) Multiply the net amount of plant, property, and equipment shown on the balance sheet by the number calculated under paragraph (b) of this section and divide the resultant product by ten.

(d) The smaller of the numbers calculated under paragraphs (a) or (c) of this section is the maximum allowable amount you may use to demonstrate OSFR under this method.

§ 553.26 What information must I submit to support my unencumbered assets demonstration?

You must support your unencumbered assets evaluation with the information required by § 553.23(a) and a list of reserved, unencumbered, and unimpaired U.S. assets whose value will not be affected by an oil discharge from a COF. The assets must be plant, property, or equipment held for use. You must submit a letter signed by your treasurer:

(a) Identifying which assets are reserved;

(b) Certifying that the assets are unencumbered, including contingent encumbrances;

(c) Promising that the identified assets will not be sold, subjected to a security interest, or otherwise encumbered throughout the specified fiscal year; and

(d) Specifying:

(1) The State or the country of incorporation;

(2) The total amount of the stockholders'/owners' equity listed on the balance sheet;

(3) The identification and location of the reserved U.S. assets; and

(4) The value of the reserved U.S. assets less accumulated depreciation and amortization, using the same valuation method used in your audited annual financial statement and expressed in U.S. dollars. The net value of the reserved assets must be at least two times the self-insurance amount requested for demonstration.

§ 553.27 When I submit audited annual financial statements to verify my unencumbered assets, what standards must they meet?

Any audited annual financial statements that you submit must:

(a) Meet the standards in § 553.24; and

(b) Include a certification by the independent accountant who audited the financial statements that states:

(1) The value of the unencumbered assets is reasonable and uses the same valuation method used in your audited annual financial statements;

(2) Any existing encumbrances are noted;

(3) The assets are long-term assets held for use; and

(4) The valuation method used in the audited annual financial statements is for long-term assets held for use.

§ 553.28 What financial test procedures must I use to evaluate the amount of self-insurance allowed as OSFR evidence based on unencumbered assets?

(a) Divide the total amount of the stockholders'/owners' equity listed on the balance sheet by 4.

(b) Divide the value of the unencumbered U.S. assets by 2.

(c) The smaller number calculated under paragraphs (a) or (b) of this section is the maximum allowable amount you may use to demonstrate OSFR under this method.

§ 553.29 How can I use insurance as OSFR evidence?

(a) If you use insurance to satisfy all or part of your obligation to demonstrate OSFR, you may use only insurance certificates issued by insurers that have achieved a ''Secure'' rating for claims paying ability in their latest review by A.M. Best's Insurance Reports, Standard & Poor's Insurance Rating Services, or other equivalent rating made by a rating service acceptable to BOEM.

(b) You must submit information about your insurers to BOEM on a completed and unaltered Form BOEM–1019. The information you submit must:

(1) Include all the information required by § 553.41 and

(2) Be executed on one original insurance certificate (*i.e.*, Form BOEM–1019) for each OSFR layer (see paragraph (c) of this section), showing all participating insurers and their proportion (quota share) of this risk. The certificate must bear the original signatures of each insurer's underwriter or of their lead underwriters, underwriting managers, or delegated brokers, depending on who is authorized to bind the underwriter.

(3) For each insurance company on the insurance certificate, indicate the insurer's claims-paying-ability rating and the rating service that issued the rating.

(c) The insurance evidence you provide to BOEM as OSFR evidence may be divided into layers, subject to the following restrictions:

(1) The total amount of OSFR evidence must equal the total amount you must demonstrate under § 553.13;

(2) No more than one insurance certificate may be used to cover each OSFR layer specified in § 553.13(b) (*i.e.*, four layers for an OCS COF, and five layers for a non-OCS COF);

(3) You may use one insurance certificate to cover any number of consecutive OSFR layers;

(4) Each insurer's participation in the covered insurance risk must be on a proportional (quota share) basis, must be expressed as a percentage of a whole layer, and the certificate must not contain intermediate, horizontal layers;

(5) You may use an insurance deductible. If you use more than one insurance certificate, the deductible amount must apply only to the certificate that covers the base OSFR amount layer. To satisfy an insurance deductible, you may use only those methods that are acceptable as evidence of OSFR under this part; and

(6) You must identify a U.S. agent for service of process on each insurance certificate you submit to BOEM. The agent may be different for each insurance certificate.

(d) You may submit to BOEM a temporary insurance confirmation (fax binder) for each insurance certificate you use as OSFR evidence. Submit your fax binder on Form BOEM–1019, and each form must include the signature of an underwriter for at least one of the participating insurers. BOEM will accept your fax binder as OSFR evidence during a period that ends 90 days after the date that you need the insurance to demonstrate OSFR.

§ 553.30 How can I use an indemnity as OSFR evidence?

(a) You may use only one indemnity issued by only one indemnitor to satisfy all or part of your obligation to demonstrate OSFR.

(b) Your indemnitor must be your corporate parent or affiliate.

(c) Your indemnitor must complete a Form BOEM–1018 and provide an indemnity that:

(1) Includes all the information required by § 553.41; and

(2) Does not exceed the amounts calculated using the net worth or unencumbered assets tests specified under §§ 553.21 through 553.28.

(d) You must submit your application to renew OSFR using an indemnity by the first calendar day of the 5th month after the close of your indemnitor's fiscal year. You may submit to BOEM your initial application to demonstrate OSFR using an indemnity at any time.

(e) Your indemnitor must identify a U.S. agent for service of process.

§ 553.31 How can I use a surety bond as OSFR evidence?

(a) Each bonding company that issues a surety bond that you submit to BOEM as OSFR evidence must:

(1) Be licensed to do business in the State in which the surety bond is executed;

(2) Be certified by the U.S. Treasury Department as an acceptable surety for Federal obligations and listed in the current Treasury Circular No. 570;

(3) Provide the surety bond on Form BOEM–1020; and

(4) Be in compliance with applicable statutes regulating surety company participation in insurance-type risks.

(b) A surety bond that you submit as OSFR evidence must include all the information required by § 553.41.

§ 553.32 Are there alternative methods to demonstrate OSFR?

The Director may accept other methods to demonstrate OSFR that provide equivalent assurance of timely satisfaction of claims. This may include pooling, letters of credit, pledges of treasury notes, or other comparable methods. Submit your proposal, together with all the supporting documents, to the Director at the address listed in § 553.45. The Director's decision whether to approve your alternative method to evidence OSFR is by this rule committed to the Director's sole discretion and is not subject to administrative appeal under 30 CFR part 590 or 43 CFR part 4.

Subpart D—Requirements for Submitting OSFR Information

§ 553.40 What OSFR evidence must I submit to BOEM?

(a) You must submit to BOEM:

(1) A single demonstration of OSFR that covers all the COFs for which you are the designated applicant;

(2) A completed and unaltered Form BOEM–1016;

(3) BOEM forms that identify your COFs (Form BOEM–1021, Form BOEM–1022), and the methods you will use to demonstrate OSFR (Form BOEM–1018, Form BOEM–1019, Form BOEM–1020). Forms are available from the address listed in § 553.45;

(4) Any insurance certificates, indemnities, and surety bonds used as OSFR evidence for the COFs for which you are the designated applicant;

(5) A completed Form BOEM–1017 for each responsible party, unless you are the only responsible party for the COFs covered by your OSFR demonstration; and

(6) Other financial instruments and information the Director requires to support your OSFR demonstration under § 553.32.

(b) Each BOEM form you submit to BOEM as part of your OSFR demonstration must be signed. You also must attach to Form BOEM–1016 proof of your authority to sign.

§ 553.41 What terms must I include in my OSFR evidence?

(a) Each instrument you submit as OSFR evidence must specify:

(1) The effective date, and except for a surety bond, the expiration date;

(2) That termination of the instrument will not affect the liability of the instrument issuer for claims arising from an incident (*i.e.*, oil-spill discharge or substantial threat of the discharge of oil) that occurred on or before the effective date of termination;

(3) That the instrument will remain in force until the termination date or until the earlier of:

(i) Thirty calendar days after BOEM and the designated applicant receive from the instrument issuer a notification of intent to cancel; or

(ii) BOEM receives from the designated applicant other acceptable OSFR evidence; or

(iii) All the COFs to which the instrument applies are permanently abandoned in compliance with 30 CFR part 250 or equivalent State requirements;

(4) That the instrument issuer agrees to direct action for claims made under OPA up to the guaranty amount, subject to the defenses in paragraph (a)(6) of this section and following the procedures in § 553.60 of this part;

(5) An agent in the United States for service of process; and

(6) That the instrument issuer will not use any defenses against a claim made under OPA except:

(i) The rights and defenses that would be available to a designated applicant or responsible party for whom the guaranty was provided; and

(ii) The incident (*i.e.*, oil-spill discharge or a substantial threat of the discharge of oil) leading to the claim for removal costs or damages was caused by willful misconduct of a responsible party for whom the designated applicant demonstrated OSFR.

(b) You may not change, omit, or add limitations or exceptions to the terms and conditions in a BOEM form that you submit as part of your OSFR demonstration. If you attempt to do this, BOEM will disregard the changes, omissions, additions, limitations, or exceptions and by operation of this rule BOEM will consider the form to

contain all the terms and conditions included on the original BOEM form.

§ 553.42 How can I amend my list of COFs?

(a) If you want to add a COF that is not identified in your current OSFR demonstration, you must submit to BOEM a completed Form BOEM–1022. If applicable, you also must submit any additional indemnities, surety bonds, insurance certificates, or other instruments required to extend the coverage of your original OSFR demonstration to the COFs to be added. You do not need to resubmit previously accepted audited annual financial statements for the current fiscal year.

(b) If you want to drop a COF identified in your current OSFR demonstration, you must submit to BOEM a completed Form BOEM–1022. You must continue to demonstrate OSFR for the COF until BOEM approves OSFR evidence for the COF from another designated applicant, or OSFR is no longer required (e.g., until a well that is a COF is properly plugged and abandoned).

§ 553.43 When is my OSFR demonstration or the amendment to my OSFR demonstration effective?

(a) BOEM will notify you in writing when we approve your OSFR demonstration. If we find that you have not submitted all the information needed to demonstrate OSFR, we may require you to provide additional information before we determine whether your OSFR evidence is acceptable.

(b) Except in the case of self-insurance or an indemnity, BOEM acceptance of OSFR evidence is valid until the surety bond, insurance certificate, or other accepted OSFR instrument expires or is canceled. In the case of self-insurance or indemnity, acceptance is valid until the first day of the 5th month after the close of your or your indemnitor's current fiscal year.

§ 553.44 [Reserved]

§ 553.45 Where do I send my OSFR evidence?

Address all correspondence and required submissions related to this part to: U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, Oil Spill Financial Responsibility Program, 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123.

Subpart E—Revocation and Penalties

§ 553.50 How can BOEM refuse or invalidate my OSFR evidence?

(a) If BOEM determines that any OSFR evidence you submit fails to comply with the requirements of this part, we may not accept it. If we do not accept your OSFR evidence, then we will send you a written notification stating:

(1) That your evidence is not acceptable;

(2) Why your evidence is unacceptable; and

(3) The amount of time you are allowed to submit acceptable evidence without being subject to civil penalty under § 553.51.

(b) BOEM may immediately and without prior notice invalidate your OSFR demonstration if you:

(1) Are no longer eligible to be the designated applicant for a COF included in your demonstration; or

(2) Permit the cancellation or termination of the insurance policy, surety bond, or indemnity upon which the continued validity of the demonstration is based.

(c) If BOEM determines you are not complying with the requirements of this part for any reason other than paragraph (b) of this section, we will notify you of our intent to invalidate your OSFR demonstration and specify the corrective action needed. Unless you take the corrective action BOEM specifies within 15 calendar days from the date you receive such a notice, we will invalidate your OSFR demonstration.

§ 553.51 What are the penalties for not complying with this part?

(a) If you fail to comply with the financial responsibility requirements of OPA at 33 U.S.C. 2716 or with the requirements of this part, then you may be liable for a civil penalty of up to $51,796 per COF per day of violation (that is, each day a COF is operated without acceptable evidence of OSFR).

(b) BOEM will determine the date of a noncompliance. BOEM will assess penalties in accordance with an OSFR penalty schedule using the procedures found at 30 CFR part 550, subpart N. You may obtain a copy of the penalty schedule from BOEM at the address in § 553.45.

(c) BOEM may assess a civil penalty against you that is greater or less than the amount in the penalty schedule after taking into account the factors in section 4303(a) of OPA (33 U.S.C. 2716a).

(d) If you fail to correct a deficiency in the OSFR evidence for a COF, then the Director may suspend operation of a COF in the OCS under 30 CFR 250.170 or seek judicial relief, including an order suspending the operation of any COF.

[76 FR 64623, Oct. 18, 2011, as amended at 81 FR 43069, July 1, 2016; 82 FR 10711, Feb. 15, 2017; 83 FR 8933, Mar. 2, 2018; 84 FR 11224, Mar. 26, 2019; 85 FR 7221, Feb. 7, 2020; 86 FR 19784, Apr. 15, 2021; 87 FR 15335, Mar. 18, 2022]

Subpart F—Claims for Oil-Spill Removal Costs and Damages

§ 553.60 To whom may I present a claim?

(a) If you are a claimant, you must present your claim first to the designated applicant for the COF that is the source of the incident resulting in your claim. If, however, the designated applicant has filed a petition for bankruptcy under 11 U.S.C. chapter 7 or 11, you may present your claim first to any of the designated applicant's guarantors.

(b) If the claim you present to the designated applicant or guarantor is denied or not paid within 90 days after you first present it or advertising begins, whichever is later, then you may seek any of the following remedies that apply:

If the reason for denial or nonpayment is . . .	Then you may elect to . . .
(1) *Not* an assertion of insolvency or petition in bankruptcy under 11 U.S.C. chapter 7 or 11,	(i) Present your claim to any of the responsible parties for the COF; or (ii) Initiate a lawsuit against the designated applicant and/or any of the responsible parties for the COF; or (iii) Present your claim to the Fund using the procedures at 33 CFR part 136.
(2) An assertion of insolvency or petition in bankruptcy under 11 U.S.C. chapter 7 or 11,	(i) Pursue any of the remedies in items (1)(i) through (iii) of this table; or (ii) Present your claim to any of the designated applicant's guarantors; or (iii) Initiate a lawsuit against any of the designated applicant's guarantors.

(c) If no one has resolved your claim to your satisfaction using the remedy that you elected under paragraph (b) of this section, then you may pursue another available remedy, unless the Fund has denied your claim or a court of competent jurisdiction has ruled against your claim. You may not pursue more than one remedy at a time.

(d) You may ask BOEM to assist you in determining whether a guarantor may be liable for your claim. Send your request for assistance to the address listed in § 553.45. You must include any information you have regarding the existence or identity of possible guarantors.

§ 553.61 When is a guarantor subject to direct action for claims?

(a) If you are a guarantor, then you are subject to direct action for any claim asserted by:

(1) The United States for any compensation paid by the Fund under OPA, including compensation claim processing costs; and

(2) A claimant other than the United States if the designated applicant has:

(i) Denied or failed to pay a claim because of being insolvent; or

(ii) Filed a petition in bankruptcy under 11 U.S.C. chapters 7 or 11.

(b) If you participate in an insurance guaranty for a COF incident (*i.e.*, oil-spill discharge or substantial threat of the discharge of oil) that is subject to

claims under this part, then your maximum, aggregate liability for those claims is equal to your quota share of the insurance guaranty.

§ 553.62 What are the designated applicant's notification obligations regarding a claim?

If you are a designated applicant, and you receive a claim for removal costs and damages, then within 15 calendar days of receipt of a claim you must notify:

(a) Your guarantors; and

(b) The responsible parties for whom you are acting as the designated applicant.

Subpart G—Limit of Liability for Offshore Facilities

SOURCE: 79 FR 73840, Dec. 12, 2014, unless otherwise noted.

§ 553.700 What is the scope of this subpart?

This subpart sets forth the limit of liability for damages for offshore facilities under Title I of the Oil Pollution Act of 1990, as amended (33 U.S.C. 2701 *et seq.*) (OPA), as adjusted, under section 1004(d) of OPA (33 U.S.C. 2704(d)). This subpart also sets forth the method for adjusting the limit of liability for damages for offshore facilities for inflation, by regulation, under section 1004(d) of OPA (33 U.S.C. 2704(d)).

§ 553.701 To which entities does this subpart apply?

This subpart applies to you if you are a responsible party for an offshore facility, other than a deepwater port under the Deepwater Port Act of 1974 (33 U.S.C. 1501–1524), but including an offshore pipeline, or an abandoned offshore facility, including any abandoned offshore pipeline, unless your liability is unlimited under OPA 90 (33 U.S.C. 2704(c)).

§ 553.702 What limit of liability applies to my offshore facility?

Except as provided in 33 U.S.C. 2704(c), the limit of liability under OPA for a responsible party for any offshore facility, including any offshore pipeline, is the total of all removal costs plus $137.6595 million for damages with respect to each incident.

[83 FR 2542, Jan. 18, 2018]

§ 553.703 What is the procedure for calculating the limit of liability adjustment for inflation?

The procedure for calculating limit of liability adjustments for inflation is as follows:

(a) *Formula for calculating a cumulative percent change in the Annual CPI–U.* BOEM calculates the cumulative percent change in the Annual CPI–U from the year the limit of liability was established by statute, or last adjusted by regulation, whichever is later (*i.e.*, the Previous Period), to the year in which the Annual CPI–U is most recently published (*i.e.*, the Current Period), using the following formula: Percent change in the Annual CPI–U = [(Annual CPI–U for Current Period − Annual CPI–U for Previous Period) ÷ Annual CPI–U for Previous Period] × 100. This cumulative percent change value is rounded to one decimal place.

(b) *Significance threshold.* (1) A cumulative increase in the Annual CPI–U equal to three percent or more constitutes a significant increase in the Consumer Price Index within the meaning of 33 U.S.C. 2704(d)(4).

(2) Not later than every three years from the year the limit of liability was last adjusted for inflation, BOEM will evaluate whether the cumulative percent change in the Annual CPI–U since that year has reached a significance threshold of three percent or greater.

(3) For any three-year period evaluated under paragraph (b)(2) of this section in which the cumulative percent increase in the Annual CPI–U is less than three percent, if BOEM has not issued an inflation adjustment during that period, BOEM will publish a notice of no inflation adjustment to the offshore facility limit of liability for damages in the FEDERAL REGISTER.

(4) Once the three-percent threshold is reached, BOEM will increase by final rule the offshore facility limit of liability for damages in § 553.702 by an amount equal to the cumulative percent change in the Annual CPI–U from the year the limit was established by statute, or last adjusted by regulation,

whichever is later. After this adjustment is made, BOEM will resume its process of conducting a review every three years.

(5) Nothing in this section will prevent BOEM, in BOEM's sole discretion, from adjusting the offshore facility limit of liability for damages for inflation by regulation issued more frequently than every three years.

(c) *Formula for calculating inflation adjustments.* BOEM calculates adjustments to the offshore facility limit of liability in 30 CFR 553.702 for inflation using the following formula:

New limit of liability = Previous limit of liability + (Previous limit of liability × the decimal equivalent of the percent change in the Annual CPI–U calculated under paragraph (a) of this section), then rounded to the closest $100.

§ 553.704 How will BOEM publish the offshore facility limit of liability adjustment?

BOEM will publish the inflation-adjusted limit of liability, and any statutory amendments to that limit of liability in the FEDERAL REGISTER, as amendments to § 553.702. Updates to the limit of liability under this section are effective on the 90th day after publication in the FEDERAL REGISTER of the amendments to § 553.702, unless otherwise specified by statute (in the event of a statutory amendment to the limit of liability), or in the FEDERAL REGISTER rule amending § 553.702.

APPENDIX TO PART 553—LIST OF U.S. GEOLOGICAL SURVEY TOPOGRAPHIC MAPS

Alabama (1:24,000 scale): Bellefontaine; Bon Secour Bay; Bridgehead; Coden; Daphne; Fort Morgan; Fort Morgan NW; Grand Bay; Grand Bay SW; Gulf Shores; Heron Bay; Hollingers Island; Isle Aux Herbes; Kreole; Lillian; Little Dauphin Island; Little Point Clear; Magnolia Springs; Mobile; Orange Beach; Perdido Beach; Petit Bois Island; Petit Bois Pass; Pine Beach; Point Clear; Saint Andrews Bay; West Pensacola.

Alaska (1:63,360 scale): Afognak (A–1, A–2, A–3, A–4, A–5, A–0&B–0, B–1, B–2, B–3, C–1&2, C–2&3, C–5, C–6, D–1, D–4, D–5); Anchorage (A–1, A–2, A–3, A–4, A–8, B–7, B–8); Barrow (A–1, A–2, A–3, A–4, A–5, B–3, B–4); Baird Mts. (A–6); Barter Island (A–3, A–4, A–5); Beechy Point (A–1, A–2, B–1, B–2, B–3, B–4, B–5, C–4, C–5); Bering Glacier (A–1, A–2, A–3, A–4, A–5, A–6, A–7, A–8); Black (A–1, A–2, B–1, C–1); Blying Sound (C–7, C–8, D–1&2, D–3, D–4, D–5, D–6, D–7, D–8); Candle (D–6); Cordova (A–1, A–2, A–3, A–4, A–7&8, B–2, B–3, B–4, B–5, B–6, B–7, B–8, C–5, C–6, C–7, C–8, D–6, D–7, D–8); De Long Mts. (D–4, D–5); Demarcation Point (C–1, C–2, D–2, D–3); Flaxman Island (A–1, A–3, A–4, A–5, B–5); Harrison Bay (B–1, B–2, B–3, B–4, C–1, C–3, C–4, C–5, D–4, D–5); Icy Bay (D1, D–2&3); Iliamna (A–2, A–3, A–4, B–2, B–3, C–1, C–2, D–1); Karluk (A–1, A–2, B–2, B–3, C–1, C–2, C–4&5, C–6); Kenai (A–4, A–5, A–7, A–8, B–4, B–6, B–7, B–8, C–4, C–5, C–6, C–7, D–1, D–2, D–3, D–4, D–5); Kodiak (A–3, A–4, A–5, A–6, B–1&2, B–3, B–4, B–6, C–1, C–2, C–3, C–5, C–6, D–1, D–2, D–3, D–4, D–5, D–6); Kotzebue (A–1, A–2, A–3, A–4, B–4, B–6, C–1, C–4, C–5, C–6, D–1, D–2); Kwiguk (C–6, D–6); Meade River (D–1, D–3, D–4, D–5); Middleton Island (B–7, D–1&2); Mt. Katmai (A–1, A–2, A–3; B–1); Mt. Michelson (D–1, D–2, D–3); Mt. St. Elias (A–5); Noatak (A–1, A–2, A–3, A–4, B–4, C–4, C–5, D–6, D–7); Nome (B–1, C–1, C–2, C–3, D–3, D–4, D–7); Norton Bay (A–4, B–4, B–5, B–6, C–4, C–5, C–6, D–4, D–5, D–6); Point Hope (A–1, A–2, B–2, B–3, C–2, C–3, D–1, D–2); Point Lay (A–3&4, B–2&3, C–2, D–1, D–2); Selawik (A–5, A–6, B–5, B–6, C–5, C–6, D–6); Seldovia (A–3, A–4, A–5, A–6, B–1, B–2, B–3, B–4, B–5, B–6, C–1, C–2, C–3, C–4, C–5, D–1, D–3, D–4, D–5, D–8); Seward (A–1, A–2, A–3, A–4, A–5, A–6, A–7, B–1, B–2, B–3, B–4, B–5, C–1, C–2, C–3, C–4, C–5, D–1, D–2, D–3, D–4, D–5, D–6, D–7, D–8); Shishmaref (A–2, A–3, A–4, B–1, B–2, B–3); Solomon (B–2, B–3, B–6, C–1, C–2, C–3, C–4, C–5, C–6); St. Michael (A–2, A–3, A–4, A–5, A–6, B–1, B–2, C–1, C–2); Teller (A–2, A–3, A–4, B–3, B–4, B–5, B–6, C–6, C–7, D–4, D–5, D–6, D–8); Teshekpuk (D–1, D–2, D–3, D–4, D–5); Tyonek (A–1, A–2, A–3, A–4, B–1, B–2); Unalakleet (B–5, B–6, C–4, C–5, D–4); Valdez (A–7, A–8); Wainwright (A–5, A–6&7, B–2, B–3, B–4, B–5&6, C–2, C–3, D–1, D–2; Yakutat (A–1, A–2, A–2, B–3, B–4, B–5, C–4, C–5, C–6, C–7, C–8, D–3, D–4, D–5, D–6, D–8).

California (1:24,000 scale): Arroyo Grande NE; Beverly Hills; Carpinteria; Casmalia; Dana Point; Del Mar; Dos Pueblos Canyon; Encinitas; Gaviota; Goleta; Guadalupe; Imperial Beach; Laguna Beach; La Jolla; Las Pulgas Canyon; Lompoc Hills; Long Beach; Los Alamitos; Malibu Beach; Morro Bay South; National City; Newport Beach; Oceano; Oceanside; Oxnard; Pismo Beach; Pitas Point; Point Arguello; Point Conception; Point Dune; Point Loma; Point Mugu; Point Sal; Port San Luis; Rancho Santa Fe; Redondo Beach; Sacate; San Clemente; San Juan Capistrano; San Luis Rey; San Onofre Bluff; San Pedro; Santa Barbara; Saticoy; Seal Beach; Surf; Tajiguas; Topanga; Torrance; Tranquillon Mountain; Triunfo Pass; Tustin; Venice; Ventura; White Ledge Peak.

Florida (1:24,000 scale): Allanton; Alligator Bay; Anna Maria; Apalachicola; Aripeka; Bayport; Beacon Beach; Beacon Hill; Bee

Ridge; Belle Meade; Belle Meade NW; Beverly; Big Lostmans Bay; Bird Keys; Bokeelia; Bonita Springs; Bradenton; Bradenton Beach; Bruce; Bunker; Cape Romano; Cape Saint George; Cape San Blas; Captiva; Carrabelle; Cedar Key; Chassahowitzka; Chassahowitzka Bay; Chiefland SW; Choctaw Beach; Chokoloskee; Clearwater; Clive Key; Cobb Rocks; Cockroach Bay; Crawfordville East; Crooked Island; Crooked Point; Cross City SW; Crystal River; Destin; Dog Island; Dunedin; East Pass; Egmont Key; El Jobean; Elfers; Englewood; Englewood NW; Estero; Everglades City; Fivay Junction; Flamingo; Fort Barrancas; Fort Myers Beach; Fort Myers SW; Fort Walton Beach; Freeport; Gandy Bridge; Garcon Point; Gator Hook Swamp; Gibsonton; Goose Island; Grayton Beach; Green Point; Gulf Breeze; Harney River; Harold SE; Holley; Holt SW; Homosassa; Horseshoe Beach; Indian Pass; Jackson River; Jena; Keaton Beach; Laguna Beach; Lake Ingraham East; Lake Ingraham West; Lake Wimico; Laurel; Lebanon Station; Lighthouse Point; Lillian; Long Point; Lostmans River Ranger Station; Manlin Hammock; Marco Island; Mary Esther; Matlacha; McIntyre; Milton South; Miramar Beach; Myakka River; Naples North; Naples South; Navarre; New Inlet; Niceville; Nutall Rise; Ochopee; Okefenokee Slough; Oldsmar; Orange Beach; Oriole Beach; Overstreet; Ozello; Pace; Palmetto; Panama City; Panama City Beach; Panther Key; Pass-A-Grille Beach; Pavillion Key; Pensacola; Perdido Bay; Pickett Bay; Pine Island Center; Placida; Plover Key; Point Washington; Port Boca Grande; Port Richey; Port Richey NE; Port Saint Joe; Port Tampa; Punta Gorda; Punta Gorda SE; Punta Gorda SW; Red Head; Red Level; Rock Islands; Royal Palm Hammock; Safety Harbor; Saint Joseph Point; Saint Joseph Spit; Saint Marks; Saint Marks NE; Saint Petersburg; Saint Teresa Beach; Salem SW; Sandy Key; Sanibel; Sarasota; Seahorse Key; Seminole; Seminole Hills; Shark Point; Shark River Island; Shired Island; Snipe Island; Sopchoppy; South of Holley; Southport; Sprague Island; Spring Creek; Springfield; Steinhatchee; Steinhatchee SE; Steinhatchee SW; Sugar Hill; Sumner; Suwannee; Tampa; Tarpon Springs; Valparaiso; Venice; Vista; Waccassasa Bay; Ward Basin; Warrior Swamp; Weavers Station; Weeki Wachee Spring; West Bay; West Pass; West Pensacola; Whitewater Bay West; Withlacoochee Bay; Wulfert; Yankeetown.

Louisiana (1:24,000 scale): Alligator Point; Barataria Pass; Bastian Bay; Bay Batiste; Bay Coquette; Bay Courant; Bay Dosgris; Bay Ronquille; Bay Tambour; Bayou Blanc; Bayou Lucien; Belle Isle; Belle Pass; Big Constance Lake; Black Bay North; Black Bay South; Breton Islands; Breton Islands SE; Buras; Burrwood Bayou East; Burwood Bayou West; Calumet Island; Cameron; Caminada Pass; Cat Island; Cat Island Pass; Central Isles Dernieres; Chandeleur Light; Chef Mentur; Cheniere Au Tigre; Cocodrie; Coquille Point; Cow Island; Creole; Cypremort Point; Deep Lake; Dixon Bay; Dog Lake; Door Point; East Bay Junop; Eastern Isles; Dernieres; Ellerslie; Empire; English Lookout; False Mouth Bayou; Fearman Lake; Floating Turf Bayou; Fourleague Bay; Franklin; Freemason Island; Garden Island Pass; Grand Bayou; Grand Bayou du Large; Grand Chenier; Grand Gosier Islands; Grand Isle; Hackberry Beach; Hammock Lake; Happy Jack; Hebert Lake; Hell Hole Bayou; Hog Bayou; Holly Beach; Intercoastal City; Isle Au Pitre; Jacko Bay; Johnson Bayou; Kemper; Lake Athanasio; Lake Cuatro Caballo; Lake Eloi; Lake Eugene; Lake Felicity; Lake La Graisse; Lake Merchant; Lake Point; Lake Salve; Lake Tambour; Leeville; Lena Lagoon; Lost Lake; Main Pass; Malheureux Point; Marone Point; Martello Castle; Mink Bayou; Mitchell Key; Morgan City SW; Morgan Harbor; Mound Point; Mulberry Island East; Mulberry Island West; New Harbor Islands; North Islands; Oak Mound Bayou; Oyster Bayou; Pass A Loutre East; Pass A Loutre West; Pass du Bois; Pass Tante Phine; Pecan Island; Pelican Pass; Peveto Beach; Pilottown; Plumb Bayou; Point Au Fer; Point Au Fer NE; Point Chevreuil; Point Chicot; Port Arthur South; Port Sulphur; Pte. Aux Marchuttes; Proctor Point; Pumpkin Islands; Redfish Point; Rollover Lake; Sabine Pass; Saint Joe Pass; Smith Bayou; South of South Pass; South Pass; Stake Islands; Taylor Pass; Texas Point; Three Mile Bay; Tigre Lagoon; Timbalier Island; Triumph; Venice; Weeks; West of Johnson Bayou; Western Isles Dernieres; Wilkinson Bay; Yscloskey.

Mississippi (1:24,000 scale): Bay Saint Louis; Biloxi; Cat Island; Chandeleur Light; Deer Island; Dog Keys Pass; English Lookout; Gautier North; Gautier South; Grand Bay SW; Gulfport North; Gulfport NW; Gulfport South; Horn Island East; Horn Island West; Isle Au Pitre; Kreole; Ocean Springs; Pascagoula North; Pascagoula South; Pass Christian; Petit Bois Island; Saint Joe Pass; Ship Island; Waveland.

Texas (1:24,000 scale): Allyns Bright; Anahuac; Aransas Pass; Austwell; Bacliff; Bayside; Big Hill Bayou; Brown Cedar Cut; Caplen; Carancahua Pass; Cedar Lakes East; Cedar Lakes West; Cedar Lane NE; Christmas Point; Clam Lake; Corpus Christi; Cove; Crane Islands NW; Crane Islands SW; Decros Point; Dressing Point; Estes; Flake; Freeport; Frozen Point; Galveston; Green Island; Hawk Island; High Island; Hitchcock; Hoskins Mound; Jones Creek; Keller Bay; Kleberg Point; La Comal; La Leona; La Parra Ranch NE; Laguna Vista; Lake Austin; Lake Como; Lake Stephenson; Lamar; Long Island; Los Amigos; Windmill; Maria Estella

Well; Matagorda; Matagorda SW; Mesquite Bay; Mission Bay; Morgans Point; Mosquito Point; Mouth of Rio Grande; Mud Lake; North of Port Isabel NW; North of Port Isabel SW; Oak Island; Olivia; Oso Creek NE; Oyster Creek; Palacios; Palacios NE; Palacios Point; Palacios SE; Panther Point; Panther Point NE; Pass Cavallo SW; Pita Island; Point Comfort; Point of Rocks; Port Aransas; Port Arthur South; Port Bolivar; Port Ingleside; Port Isabel; Port Isabel NW; Port Lavaca East; Port Mansfield; Port O'Connor; Portland; Potrero Cortado; Potrero Lopeno NW; Potrero Lopeno SE; Potrero Lopeno SW; Rockport; Sabine Pass; San Luis Pass; Sargent; Sea Isle; Seadrift; Seadrift NE; Smith Point; South Bird Island; South Bird Island NW; South Bird Island SE; South of Palacios Point; South of Potrero Lopeno NE; South of Potrero Lopeno NW; South of Potrero Lopeno SE; South of Star Lake; St. Charles Bay; St. Charles Bay SE; St. Charles Bay SW; Star Lake; Texas City; Texas Point; The Jetties; Three Islands; Tivoli SE; Turtle Bay; Umbrella Point; Virginia Point; West of Johnson Bayou; Whites Ranch; Yarborough Pass.

PART 556—LEASING OF SULFUR OR OIL AND GAS AND BONDING REQUIREMENTS IN THE OUTER CONTINENTAL SHELF

Subpart A—General Provisions

Sec.
556.100 Statement of policy.
556.101 Purpose.
556.102 Authority.
556.103 Cross references.
556.104 Information collection and proprietary information.
556.105 Acronyms and definitions.
556.106 Service fees.
556.107 Corporate seal requirements.

Subpart B—Oil and Gas Five Year Leasing Program

556.200 What is the Five Year leasing program?
556.201 Does BOEM consider multiple uses of the OCS?
556.202 How does BOEM start the Five Year program preparation process?
556.203 What does BOEM do before publishing a proposed Five Year program?
556.204 How do Governments and citizens comment on a proposed Five Year program?
556.205 What does BOEM do before approving a proposed final Five Year program or a significant revision of a previously-approved Five Year program?

Subpart C—Planning and Holding a Lease Sale

556.300 What reports may BOEM and other Federal agencies prepare before a lease sale?
556.301 What is a Call for Information and Nominations?
556.302 What does BOEM do with the information from the Call?
556.303 What does BOEM do if an area proposed for leasing is within three nautical miles of the seaward boundary of a coastal State?
556.304 How is a proposed notice of sale prepared?
556.305 How does BOEM coordinate and consult with States regarding a proposed notice of sale?
556.306 What if a potentially oil or gas bearing area underlies both the OCS and lands subject to State jurisdiction?
556.307 What does BOEM do with comments and recommendations received on the proposed notice of sale?
556.308 How does BOEM conduct a lease sale?
556.309 Does BOEM offer blocks in a sale that is not on the Five Year program schedule (called a Supplemental Sale)?

Subpart D—Qualifications

556.400 When must I demonstrate that I am qualified to hold a lease on the OCS?
556.401 What do I need to show to become qualified to hold a lease on the OCS and obtain a qualification number?
556.402 How do I make the necessary showing to qualify and obtain a qualification number?
556.403 Under what circumstances may I be disqualified from holding a lease on the OCS?
556.404 What do the non-procurement debarment rules require that I do?
556.405 When must I notify BOEM of mergers, name changes, or changes of business form?

Subpart E—Issuance of a Lease

HOW TO BID

556.500 Once qualified, how do I submit a bid?
556.501 What information do I need to submit with my bid?

RESTRICTIONS ON JOINT BIDDING

556.511 Are there restrictions on bidding with others and do those restrictions affect my ability to bid?
556.512 What bids may be disqualified?
556.513 When must I file a statement of production?

556.514 How do I determine my production for purposes of the restricted joint bidders list?
556.515 May a person be exempted from joint bidding restrictions?

HOW DOES BOEM ACT ON BIDS?

556.516 What does BOEM do with my bid?
556.517 What may I do if my bid is rejected?

AWARDING THE LEASE

556.520 What happens if I am the successful high bidder and BOEM accepts my bid?
556.521 When is my lease effective?
556.522 What are the terms and conditions of the lease and when are they published?

Subpart F—Lease Terms and Obligations

LENGTH OF LEASE

556.600 What is the primary term of my oil and gas lease?
556.601 How may I maintain my oil and gas lease beyond the primary term?
556.602 What is the primary term of my sulfur lease?
556.603 How may I maintain my sulfur lease beyond the primary term?

LEASE OBLIGATIONS

56.604 What are my rights and obligations as a record title owner?
556.605 What are my rights and obligations as an operating rights owner?

HELIUM

556.606 What must a lessee do if BOEM elects to extract helium from a lease?

Subpart G—Transferring All or Part of the Record Title Interest in a Lease

556.700 May I assign or sublease all or any part of the record title interest in my lease?
556.701 How do I seek approval of an assignment of the record title interest in my lease, or a severance of operating rights from that record title interest?
556.702 When will my assignment result in a segregated lease?
556.703 What is the effect of the approval of the assignment of 100 percent of the record title in a particular aliquot(s) of my lease and the resulting lease segregation?
556.704 When would BOEM disapprove an assignment or sublease of an interest in my lease?
556.705 How do I transfer the interest of a deceased natural person who was a lessee?
556.706 What if I want to transfer record title interests in more than one lease at the same time, but to different parties?
556.707 What if I want to transfer different types of lease interests (not only record title interests) in the same lease to different parties?
556.708 What if I want to transfer my record title interests in more than one lease to the same party?
556.709 What if I want to transfer my record title interest in one lease to multiple parties?
556.710 What is the effect of an assignment of a lease on an assignor's liability under the lease?
556.711 What is the effect of a record title holder's sublease of operating rights on the record title holder's liability?
556.712 What is the effective date of a transfer?
556.713 What is the effect of an assignment of a lease on an assignee's liability under the lease?
556.714 As a restricted joint bidder, may I transfer an interest to another restricted joint bidder?
556.715 Are there any interests I may transfer or record without BOEM approval?
556.716 What must I do with respect to the designation of operator on a lease when a transfer of record title is submitted?

Subpart H—Transferring Operating Rights in All or Part of a Lease

556.800 As an operating rights owner, may I assign all or part of my operating rights interest?
556.801 How do I seek approval of an assignment of my operating rights?
556.802 When would BOEM disapprove the assignment of all or part of my operating rights interest?
556.803 What if I want to assign operating rights interests in more than one lease at the same time, but to different parties?
556.804 What if I want to assign my operating rights interest in a lease to multiple parties?
556.805 What is the effect of an operating rights owner's assignment of operating rights on the assignor's liability?
556.806 What is the effective date of an assignment of operating rights?
556.807 What is the effect of an assignment of operating rights on an assignee's liability?
556.808 As an operating rights owner, are there any interests I may assign without BOEM approval?
556.809 [Reserved]
556.810 What must I do with respect to the designation of operator on a lease when a transfer of operating rights ownership is submitted?

Subpart I—Bonding or Other Financial Assurance

556.900 Bond requirements for an oil and gas or sulfur lease.
556.901 Additional bonds.
556.902 General requirements for bonds.
556.903 Lapse of bond.
556.904 Lease-specific abandonment accounts.
556.905 Using a third-party guarantee instead of a bond.
556.906 Termination of the period of liability and cancellation of a bond.
556.907 Forfeiture of bonds and/or other securities.

Subpart J—Bonus or Royalty Credits for Exchange of Certain Leases

556.1000 Leases formerly eligible for a bonus or royalty credit.

Subpart K—Ending a Lease

556.1100 How does a lease expire?
556.1101 May I relinquish my lease or an aliquot part thereof?
556.1102 Under what circumstances will BOEM cancel my lease?

Subpart L—Leases Maintained Under Section 6 of OCSLA

556.1200 Effect of regulations on lease.
556.1201 Section 6(a) leases and leases other than those for oil, gas, or sulfur.

Subpart M—Environmental Studies

556.1300 Environmental studies.

AUTHORITY: 30 U.S.C. 1701 note, 30 U.S.C. 1711, 31 U.S.C. 9701, 42 U.S.C. 6213, 43 U.S.C. 1331 note, 43 U.S.C. 1334, 43 U.SC. 1801–1802.

SOURCE: 81 FR 18152, Mar. 30, 2016, unless otherwise noted.

Subpart A—General Provisions

§ 556.100 Statement of policy.

The management of Outer Continental Shelf (OCS) 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 (OCSLA or the Act) (43 U.S.C. 1332, 1801, 1802), and other executive, legislative, judicial and departmental guidance. The Secretary of the Interior (the Secretary) will consider available environmental information in making decisions affecting OCS resources.

§ 556.101 Purpose.

The purpose of the regulations in this part is to establish the procedures under which the Secretary will exercise the authority to administer a leasing program for oil and gas, and sulfur. The regulations pertaining to the procedures under which the Secretary will exercise the authority to administer a program to grant rights-of-use and easements are found in part 550 of this chapter.

§ 556.102 Authority.

(a) The Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1334) authorizes the Secretary of the Interior to issue, on a competitive basis, leases for oil and gas, and sulfur, in submerged lands of the OCS. The Act authorizes the Secretary to grant rights-of-way and easements through the submerged lands of the OCS.

(b) The Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA) (30 U.S.C. 1711) governs oil and gas royalty management and requires the development of enforcement practices to ensure the prompt and proper collection of oil and gas revenues owed to the U.S.

(c) The Independent Offices Appropriations Act of 1952 (IOAA) (31 U.S.C. 9701) authorizes fees and charges for Federal government services.

(d) The Energy Policy and Conservation Act of 1975 (42 U.S.C. 6213) prohibits joint bidding by major oil and gas producers.

(e) The Gulf of Mexico Energy Security Act of 2006 (GOMESA) (Pub. L. 109–432, 43 U.S.C. 1331 note):

(1) Shares leasing revenues with Gulf producing states and the Land & Water Conservation Fund for coastal restoration projects; and

(2) Allows companies to exchange certain existing leases in moratorium areas for bonus and royalty credits to be used on other Gulf of Mexico leases.

§ 556.103 Cross references.

The following includes some of the major regulations relevant to offshore oil and gas development:

(a) For other applicable Bureau of Ocean Energy Management (BOEM) oil and gas regulations, see 30 CFR parts 550 through 560.

(b) For Bureau of Safety and Environmental Enforcement (BSEE) regulations governing exploration, development and production, and oil spill response, see 30 CFR chapter II.

(c) For Office of Natural Resources Revenue (ONRR) regulations related to rentals, royalties, and fees, see 30 CFR chapter XII.

(d) For BOEM regulations governing the appeal of an order or decision issued under the regulations in this part, see 30 CFR part 590.

(e) For regulations on the National Environmental Policy Act (NEPA), see 40 CFR 1500–1508 and 43 CFR part 46.

(f) For ocean dumping sites, see the U.S. Environmental Protection Agency (USEPA) listing—40 CFR part 228.

(g) For air quality, see USEPA regulations at 40 CFR part 55 and BOEM regulations at 30 CFR part 550 subparts B and C.

(h) For related National Oceanic and Atmospheric Administration (NOAA) programs, see:

(1) Marine Sanctuary regulations, 15 CFR part 922;

(2) Fishermen's Contingency Fund, 50 CFR part 296;

(3) Coastal Zone Management Act (CZMA), 15 CFR part 930;

(4) Essential Fish Habitat, 50 CFR 600.90.

(i) For U.S. Coast Guard (USCG) regulations on the oil spill liability of vessels and operators, see 33 CFR parts 132, 135, and 136.

(j) For USCG regulations on port access routes, see 33 CFR part 164.

(k) For Department of Transportation regulations on offshore pipeline facilities, see 49 CFR part 195.

(l) For Department of Defense regulations on military activities on offshore areas, see 32 CFR part 252.

§ 556.104 Information collection and proprietary information.

(a) *Information collection*. (1) The Office of Management and Budget (OMB) approved the collection of information under 44 U.S.C. 3501–3521), and assigned OMB Control Number 1010–0006. The title of this collection of information is ''Leasing of Sulfur or Oil and Gas in the Outer Continental Shelf (30 CFR part 550, part 556, and part 560).''

(2) BOEM collects this information to determine if an applicant seeking to obtain a lease or right-of-use and easement (RUE) on the OCS is qualified to hold such a lease or RUE and to determine whether any such applicant can meet the monetary and non-monetary requirements associated with a lease or RUE. Responses to this information collection are either required to obtain or retain a benefit or are mandatory under OCSLA (43 U.S.C. 1331–1356a). BOEM will protect proprietary information collected according to section 26 of OCSLA (43 U.S.C. 1352), and this section.

(3) The Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3521) requires us to inform the public that an agency may not conduct or sponsor, and that no one is required to respond to, a collection of information unless it displays a current and valid OMB control number.

(4) 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, Bureau of Ocean Energy Management, by mail at 45600 Woodland Road, Sterling, VA 20166 or by email to *regulation1@boem.gov*, or by phone at (703) 787–1025.

(b) *Proprietary information*. (1) Any proprietary information maintained by BOEM will be subject to the requirements of 43 CFR part 2.

(2) No proprietary information received by BOEM under 43 U.S.C. 1352(c) will be transmitted to any affected State unless the lessee, to whom such information applies, or the permittee and all persons, to whom such permittee has sold such information under promise of confidentiality, agree to such transmittal.

(c) Proprietary information in response to a Call for Information and Nominations (Call).

(1) A specific indication of interest in an area received in response to a Call issued by the Secretary is proprietary information.

(2) Notwithstanding paragraph (c)(1) of this section, BOEM may provide a summary of indications of interest in areas received in response to a Call for a proposed sale.

§ 556.105 Acronyms and definitions.

(a) Acronyms and terms used in this part have the following meanings:

ASTM American Society for Testing and Materials
BAST Best Available and Safest Technology
BOEM Bureau of Ocean Energy Management
BSEE Bureau of Safety and Environmental Enforcement
CFR Code of Federal Regulations
CPA Central Planning Area of the GOM
CZMA Coastal Zone Management Act
DOI Department of the Interior
DOCD Development Operations Coordination Document
DOO Designation of Operator
DPP Development and Production Plan
EIA Environmental Impact Analysis
EP Exploration Plan
EPA Eastern Planning Area of the GOM
EPAct Energy Policy Act of 2005
FNOS Final Notice of Sale
FOGRMA Federal Oil and Gas Royalty Management Act of 1982
G&G Geological and Geophysical
GDIS Geophysical Data and Information Statement
GOM Gulf of Mexico
GOMESA Gulf of Mexico Energy Security Act of 2006
IOAA Independent Offices Appropriations Act of 1952
LLC Limited Liability Company
MBB Mapping and Boundary Branch
NAD North American Datum
NEPA National Environmental Policy Act of 1969
NGPA Natural Gas Processors Association
NOAA National Oceanic and Atmospheric Administration
NTL Notice to Lessees
OCS Outer Continental Shelf
OCSLA Outer Continental Shelf Lands Act
OMB Office of Management and Budget
ONRR Office of Natural Resources Revenue
OPD Official Protraction Diagram
PNOS Proposed Notice of Sale
PRA Paperwork Reduction Act
ROW Right of way
RSV Royalty Suspension Volume
RUE Right of Use and Easement
SLA Submerged Lands Act of 1953
U.S. United States
U.S.C. United States Code
USCG U.S. Coast Guard
USEPA U.S. Environmental Protection Agency
UTM Universal Transverse Mercator coordinate system
WPA Western Planning Area of the GOM

(b) As used in this part, each of the terms and phrases listed below has the meaning given in the Act or as defined in this section.

Act means the Outer Continental Shelf Lands Act, as amended (OCSLA) (43 U.S.C. 1331–1356a).

Affected State means, with respect to any program, plan, lease sale, or other activity proposed, conducted, or approved pursuant to the provisions of OCSLA, any State:

(i) The laws of which are declared, pursuant to section 4(a)(2) of OCSLA (43 U.S.C. 1333(a)(2)), 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;

(ii) 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 OCSLA (43 U.S.C. 1333(a)(1));

(iii) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment that was extracted from the OCS and transported directly to that State by means of one or more vessels or by a combination of means, including a vessel;

(iv) 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 OCS; or

(v) 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 one or more vessels, pipelines, or other transshipment facilities.

Aliquot or Aliquot part means an officially designated subdivision of a lease's area, which can be a half of a lease (½), a quarter of a lease (¼), a quarter of a quarter of a lease (¼ ¼), or a quarter of a quarter of a quarter of a lease (¼ ¼ ¼).

Authorized officer means any person authorized by law or by delegation of

authority to or within BOEM to perform the duties described in this part.

Average daily production means the total of all production in an applicable production period that is chargeable under § 556.514 divided by the exact number of calendar days in the applicable production period.

Barrel means 42 U.S. gallons. All measurements of crude oil and natural gas liquids under this section must be at 60 °F.

(i) For purposes of computing production and reporting of natural gas, 5,626 cubic feet of natural gas at 14.73 pounds per square inch equals one barrel.

(ii) For purposes of computing production and reporting of natural gas liquids, 1.454 barrels of natural gas liquids at 60 °F equals one barrel of crude oil.

Bidding unit means one or more OCS blocks, or any portion thereof, that may be bid upon as a single administrative unit and will become a single lease. The term 'tract,'' as defined in this section, may be used interchangeably with the term ''bidding unit.''

BOEM means Bureau of Ocean Energy Management of the U.S. Department of the Interior.

Bonus or royalty credit means a legal instrument or other written documentation approved by BOEM, or an entry in an account managed by the Secretary, that a bidder or lessee may use in lieu of any other monetary payment for a bonus or a royalty due on oil or gas production from certain leases, as specified in, and permitted by, the Gulf of Mexico Energy Security Act of 2006, Pub. L. 109–432 (Div. C, Title 1), 120 Stat. 3000 (2006), codified at 43 U.S.C. 1331, note.

BSEE means Bureau of Safety and Environmental Enforcement of the U.S. Department of the Interior.

Central Planning Area (CPA) means that portion of the Gulf of Mexico that lies southerly of Louisiana, Mississippi, and Alabama. Precise boundary information is available from the BOEM Leasing Division, Mapping and Boundary Branch (MBB).

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the productivity, state, condition, and quality of the terrestrial ecosystem from the shoreline inland 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 water therein and thereunder), strongly influenced by each other and in proximity to the shorelines of one or more of the several coastal States, and includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches, whose 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 inland boundaries of which may be identified by the several coastal States, under section 305(b)(1) of the Coastal Zone Management Act (CZMA) of 1972, 16 U.S.C. 1454(b)(1).

Coastline means the line of mean ordinary low water along that portion of the coast in direct contact with the open sea and the line marking the seaward limit of inland waters.

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.

Designated operator means a person authorized to act on your behalf and fulfill your obligations under the Act, the lease, and the regulations, who has been designated as an operator by all record title holders and all operating rights owners that own an operating rights interest in the aliquot/depths in which the designated operator, to which the Designation of Operator form applies, will be operating, and who has been approved by BOEM to act as designated operator.

Desoto Canyon OPD means the Official Protraction Diagram (OPD) designated as Desoto Canyon that has a western edge located at the universal transverse mercator (UTM) X coordinate 1,346,400 in the North American Datum of 1927 (NAD27).

Destin Dome OPD means the Official Protraction Diagram (OPD) designated as Destin Dome that has a western edge located at the Universal Transverse Mercator (UTM) X coordinate 1,393,920 in the NAD27.

Development block means a block, including a block susceptible to drainage, which is located on the same general geologic structure as an existing lease having a well with indicated hydrocarbons; a reservoir may or may not be interpreted to extend on to the block.

Director means the Director of the BOEM of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

Eastern Planning Area (EPA) means that portion of the Gulf of Mexico that lies southerly and westerly of Florida. Precise boundary information is available from the BOEM Leasing Division, Mapping and Boundary Branch.

Economic interest means any right to, or any right dependent upon, production of crude oil, natural gas, or natural gas liquids and includes, but is not limited to: a royalty interest; an overriding royalty interest, whether payable in cash or kind; a working interest that does not include a record title interest or an operating rights interest; a carried working interest; a net profits interest; or a production payment.

Human environment means the physical, social, and economic components, conditions, and factors that 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.

Initial period or primary term means the initial period referred to in 43 U.S.C. 1337(b)(2).

Joint bid means a bid submitted by two or more persons for an oil and gas lease under section 8(a) of the Act.

Lease means an agreement that is issued under section 8 or maintained under section 6 of the Act and that authorizes exploration for, and development and production of, minerals on the OCS. The term also means the area covered by that agreement, whichever the context requires.

Lease interest means one or more of the following ownership interests in an OCS oil and gas or sulfur lease: a record title interest, an operating rights interest, or an economic interest.

Lessee means a person who has entered into a lease with the United States to explore for, develop, and produce the leased minerals and is therefore a record title owner of the lease, or the BOEM-approved assignee-owner of a record title interest. The term lessee also includes the BOEM-approved sublessee- or assignee-owner of an operating rights interest in a lease.

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that 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 OCS.

Mineral means oil, gas, and sulfur; it also includes sand, gravel, and salt used to facilitate the development and production of oil, gas, and sulfur.

Natural gas means a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist in the gaseous phase.

Natural gas liquids means liquefied petroleum products produced from reservoir gas and liquefied at surface separators, field facilities, or gas processing plants worldwide, including any of the following:

(i) Condensate—natural gas liquids recovered from gas well gas (associated and non-associated) in separators or field facilities; or

(ii) Gas plant products—natural gas liquids recovered from natural gas in gas processing plants and from field facilities. Gas plant products 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, including isobutane, normal butane, and 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, that meets 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.).

Operating rights means an interest created by sublease out of the record title interest in an oil and gas lease, authorizing the owner to explore for, develop, and/or produce the oil and gas contained within a specified area and depth of the lease (*i.e.*, operating rights tract).

Operating rights owner means the holder of operating rights.

Operating rights tract means the area within the lease from which the operating rights have been severed on an aliquot basis from the record title interest, defined by a beginning and ending depth.

Operator means the person designated as having control or management of operations on the leased area or a portion thereof. An operator may be a lessee, the operating rights owner, or a designated agent of the lessee or the operating rights owner.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in the Submerged Lands Act (43 U.S.C. 1301–1315) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Outer Continental Shelf Lands Act (OCSLA) means the Outer Continental Shelf Lands Act (43 U.S.C. 1331–1356a), as amended.

Owned, as used in the context of restricted joint bidding or a statement of production, means:

(i) With respect to crude oil—having either an economic interest in or a power of disposition over the production of crude oil;

(ii) With respect to natural gas—having either an economic interest in or a power of disposition over the production of natural gas; and

(iii) With respect to natural gas liquids—having either an economic interest in or a power of disposition over any natural gas liquids at the time of completion of the liquefaction process.

Pensacola OPD means the Official Protraction Diagram (OPD) designated as Pensacola that has a western edge located at the UTM X coordinate 1,393,920 in the NAD27.

Person means a natural person, where so designated, or an entity, such as a partnership, association, State, political subdivision of a State or territory, or a private, public, or municipal corporation.

Planning area means a large portion of the OCS, consisting of contiguous OCS blocks, defined for administrative planning purposes.

Primary term or initial period means the initial period referred to in 43 U.S.C. 1337(b)(2).

Regional Director means the BOEM officer with responsibility and authority for a Region within BOEM.

Regional Supervisor means the BOEM officer with responsibility and authority for leasing or other designated program functions within a BOEM Region.

Right-of-Use and Easement (RUE) means a right to use a portion of the seabed at an OCS site other than on a lease you own, for the construction and/or use of artificial islands, facilities, installations, and other devices, established to support the exploration, development or production of oil and gas, mineral, or energy resources from an OCS or State submerged lands lease.

Right-of-Way (ROW) means an authorization issued by BSEE under the authority of section 5(e) of the OCSLA (43 U.S.C. 1334(e)) for the use of submerged lands of the Outer Continental Shelf for pipeline purposes.

Secretary means the Secretary of the Interior or an official or a designated employee authorized to act on the Secretary's behalf.

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.

Single bid means a bid submitted by one person for an oil and gas lease under section 8(a) of the Act.

Six-month bidding period means the 6-month period of time:

(i) From May 1 through October 31; or

(ii) from November 1 through April 30.

Statement of production means, in the context of joint restricted bidders, the following production during the applicable prior production period:

(i) The average daily production in barrels of crude oil, natural gas, and natural gas liquids which it owned worldwide;

(ii) The average daily production in barrels of crude oil, natural gas, and natural gas liquids owned worldwide by every subsidiary of the reporting person;

(iii) The average daily production in barrels of crude oil, natural gas, and natural gas liquids owned worldwide by any person or persons of which the reporting person is a subsidiary; and

(iv) The average daily production in barrels of crude oil, natural gas, and natural gas liquids owned worldwide by any subsidiary, other than the reporting person, of any person or persons of which the reporting person is a subsidiary.

Tract means one or more OCS blocks, or any leasable portion thereof, that will be part of a single oil and gas lease. The term tract may be used interchangeably with the term ''bidding unit.''

We, us, and our mean BOEM or the Department of the Interior, depending on the context in which the word is used.

Western Planning Area (WPA) means that portion of the Gulf of Mexico that lies south and east of Texas. Precise boundary information is available from the Leasing Division, Mapping and Boundary Branch.

You, depending on the context of the regulations, means a bidder, a prospective bidder, a lessee (record title owner), an operating rights owner, an applicant seeking to become an assignee of record title or operating rights, a designated operator or agent of the lessee, a predecessor lessee, a RUE holder for a State or Federal lease, or a pipeline ROW holder.

[81 FR 18152, Mar. 30, 2016, as amended at 81 FR 70358, Oct. 12, 2016]

§ 556.106 Service fees.

(a) The table in this paragraph shows the fees you must pay to BOEM for the services listed. BOEM will adjust the fees periodically according to the Implicit Price Deflator for Gross Domestic Product and publish a document showing the adjustment in the FEDERAL REGISTER. If a significant adjustment is needed to arrive at a new fee for any reason other than inflation, then a proposed rule containing the new fees will be published in the FEDERAL REGISTER for comment.

SERVICE FEE TABLE

Service—processing of the following:	Fee amount	30 CFR Citation
(1) Assignment of record title interest in Federal oil and gas lease(s) for BOEM approval.	$198	§ 556.701(a)
(2) Sublease or Assignment of operating rights interest in Federal oil and gas lease(s) for BOEM approval.	198	§ 556.801(a)
(3) Required document filing for record purpose, but not for BOEM approval.	29	§ 556.715(a) § 556.808(a)
(4) Non-required document filing for record purposes.	29	§ 556.715(b) § 556.808(b)

(b) Evidence of payment via *pay.gov* of the fees listed in paragraph (a) of this section must accompany the submission of a document for approval or filing, or be sent to an office identified by the Regional Director.

(c) Once a fee is paid, it is nonrefundable, even if your service request is withdrawn.

(d) If your request is returned to you as incomplete, you are not required to submit a new fee with the amended submission.

(e) The *pay.gov* Web site is accessible at *https://www.pay.gov/paygov/* or through the BOEM Web site at *http://www.boem.gov/Fees-for-Services*.

(f) The fees listed in the table above apply equally to any document or information submitted electronically pursuant to part 560, subpart E, of this chapter.

§ 556.107 Corporate seal requirements.

(a) If you electronically submit to BOEM any document or information referenced in § 560.500 of this chapter, any requirement to use a corporate seal under this chapter will be satisfied, and you will not need to affix your corporate seal to such document or information, if:

(1) You properly file with BOEM a paper, with a corporate seal and the signature of the authorized person(s), stating that electronic submissions made by you will be legally binding, as set forth in § 560.502 of this chapter; and

(2) You make electronic submissions to BOEM through a secure electronic filing system that conforms to the requirements of § 560.500; or,

(b) You may file with BOEM a non-electronic document, containing a corporate seal and the signature of an authorized person(s), attesting that future documents and information filed by you by electronic or non-electronic means will be legally binding without an affixed corporate seal. If you file such a non-electronic attestation document with BOEM, any requirement for use of a corporate seal under the regulations of this chapter will be satisfied, and you will not need to affix your corporate seal to submissions where they would have been otherwise required.

(c) If the State or territory in which you are incorporated does not issue or require corporate seals, the document referred to in paragraphs (a) and (b) of this section need not contain a corporate seal, but must still contain the signature of the authorized person(s), a statement that the State in which you are incorporated does not issue or require corporate seals, and a statement that submissions made by you will be legally binding.

(d) Any document, or information submitted without corporate seal must still contain the signature of an individual qualified to sign who has the requisite authority to act on your behalf.

(e) Any document or information submitted pursuant to this section is submitted subject to the penalties of 18 U.S.C. 1001, as amended by the False Statements Accountability Act of 1996.

Subpart B—Oil and Gas Five Year Leasing Program

§ 556.200 What is the Five Year leasing program?

Section 18(a) of OCSLA (43 U.S.C. 1344(a)), requires the Secretary to prepare an oil and gas leasing program that consists of a five-year schedule of proposed lease sales to best meet national energy needs, showing the size, timing, and location of leasing activity as precisely as possible. BOEM prepares the five year schedule of proposed lease sales consistent with the principles set out in section 18(a)(1) and (2)(A)-(H) of OCSLA (43 U.S.C. 1344(a)(1) and (2)(A)-(H)) to obtain a proper balance among the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone, as required by OCSLA section 18(a)(3) (43 U.S.C. 1344(a)(3)).

§ 556.201 Does BOEM consider multiple uses of the OCS?

BOEM gathers information about multiple uses of the OCS in order to assist the Secretary in making decisions on the 5-year program pursuant to provisions of 43 U.S.C. 1344. For this purpose, BOEM invites and considers suggestions from States and local governments, industry, and any other interested parties, primarily through public notice and comment procedures. BOEM

also invites and considers suggestions from Federal agencies.

§ 556.202 How does BOEM start the Five Year program preparation process?

To begin preparation of the Five Year program, BOEM invites and considers nominations for any areas to be included or excluded from leasing, by doing the following:

(a) BOEM prepares and makes public official protraction diagrams and leasing maps of OCS areas. In any area properly included in the official Five Year diagrams and maps, any area not already leased for oil and gas may be offered for lease.

(b) BOEM invites and considers suggestions and relevant information from governors of States, local governments, industry, Federal agencies, and other interested parties, through a publication of a request for information in the FEDERAL REGISTER. Any local government must first submit its comments on the request for information to its State governor before sending the comments to BOEM.

(c) BOEM sends a letter to the governor of each affected State asking the governor to identify specific laws, goals, and policies that should be considered. Each State governor, as well as the Department of Commerce, is requested to identify the relationship between any oil and gas activity and the State under sections 305 and 306 of the CZMA, 16 U.S.C. 1454 and 1455.

(d) BOEM asks the Department of Energy for information on regional and national energy markets and transportation networks.

§ 556.203 What does BOEM do before publishing a proposed Five Year program?

After considering the comments and information described in § 556.202, BOEM will prepare a draft proposed Five Year program.

(a) At least 60 days before publication of a proposed program, BOEM will send a letter, together with the draft proposed program, to the governor of each affected State, inviting the governor to comment on the draft proposed program.

(b) A governor, whether for purposes of preparing that State's comments or otherwise, may solicit comments from local governments that he determines may be affected by an oil and gas leasing program.

(c) If a governor's comments on the draft proposed program are received by BOEM at least 15 days before submission of the proposed program to Congress and its publication for comment in the FEDERAL REGISTER, BOEM will reply to the governor in writing.

§ 556.204 How do governments and citizens comment on a proposed Five Year program?

BOEM publishes the proposed program in the FEDERAL REGISTER for comment by the public. At the same time, BOEM sends the proposed program to the governors of the affected States and to Congress and the Attorney General of the United States for review and comment.

(a) Governors are responsible for providing a copy of the proposed program to affected local governments in their States. Local governments may comment directly to BOEM, but must also send their comments to the governor of their State.

(b) All comments from any party are due within 90 days after publication of the request for comments in the FEDERAL REGISTER.

§ 556.205 What does BOEM do before approving a proposed final Five Year program or a significant revision of a previously-approved Five Year program?

At least 60 days before the Secretary may approve a proposed final Five Year program or a significant revision to a previously approved final Five Year program, BOEM will submit a proposed final program or proposed significant revision to the President and Congress. BOEM will also submit comments received and indicate the reasons why BOEM did or did not accept any specific recommendation of the Attorney General of the United States, the governor of a State, or the executive of a local government.

Subpart C—Planning and Holding a Lease Sale

§ 556.300 What reports may BOEM and other Federal agencies prepare before a lease sale?

For an oil and gas lease sale in a Five Year program, and as the need arises for other mineral leasing pursuant to part 581 of this chapter, BOEM will 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.

§ 556.301 What is a Call for Information and Nominations?

BOEM issues a Call for Information and Nominations (''Call'') on an area proposed for leasing in the Five Year program through publication in the FEDERAL REGISTER and other publications. A Call may include more than one proposed sale. Comments are requested from industry and the public on:

(a) Industry interest in the area proposed for leasing, including nominations or indications of interest in specific blocks within the area;

(b) Geological conditions, including bottom hazards;

(c) Archaeological sites on the seabed or near shore;

(d) Potential multiple uses of the proposed leasing area, including navigation, recreation, and fisheries;

(e) Areas that should receive special concern and analysis; and

(f) Other socioeconomic, biological, and environmental information.

§ 556.302 What does BOEM do with the information from the Call?

(a) Based upon information and nominations received in response to the Call, and in consultation with appropriate Federal agencies, the Director will develop a recommendation of areas proposed for leasing for the Secretary for further consideration for leasing and/or environmental analysis.

(1) In developing the recommendation, the Director will consider available information concerning the environment, conflicts with other uses, resource potential, industry interest, and other relevant information, including comments received from State and local governments and other interested parties in response to the Call.

(2) 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 will consider all available environmental information.

(3) Upon approval by the Secretary, the Director will announce the area identified in the FEDERAL REGISTER.

(b) BOEM will evaluate the area(s) identified for further consideration for the potential effects of leasing on the human, marine, and coastal environments, and may develop measures to mitigate adverse impacts, including lease stipulations, for the options to be analyzed. The Director may hold public hearings on the environmental analysis after an appropriate notice.

(c) BOEM will seek to inform the public, as soon as possible, of changes from the area(s) proposed for leasing that occur after the Call process.

(d) Upon request, the Director will provide relative indications of interest in areas, as well as any comments filed in response to a Call for a proposed sale. However, no information transmitted will 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.

(e) For supplemental sales provided for by § 556.308, the Director's recommendation will be replaced by a statement describing the results of the Director's consideration of the factors specified above in this section.

§ 556.303 What does BOEM do if an area proposed for leasing is within three nautical miles of the seaward boundary of a coastal State?

For an area proposed for leasing that is within three nautical miles of the seaward boundary of a coastal State, as

governed by section 8(g)(1) of OCSLA (43 U.S.C. 1337(g)(1)):

(a) BOEM provides the governor of the coastal State, subject to the confidentiality requirements in this chapter:

(1) A schedule for leasing; and

(2) An estimate of the potential oil and gas resources.

(b) At the request of the governor of a coastal State, BOEM will provide to that governor, subject to the confidentiality requirements in this chapter:

(1) Information concerning geographical, geological, and ecological characteristics; and

(2) An identification of any field, geological structure, or trap, or portion thereof, that lies within three nautical miles of the State's boundary.

§ 556.304 How is a proposed notice of sale prepared?

(a) The Director will, in consultation with appropriate Federal agencies, develop measures, including lease stipulations and conditions, to mitigate adverse impacts on the environment, which will be contained, or referenced, in the proposed notice of sale.

(b) A proposed notice of sale will be submitted to the Secretary for approval. All comments and recommendations received and the Director's findings or actions thereon, will also be forwarded to the Secretary.

(c) Upon approval by the Secretary, BOEM will send a proposed notice of sale to the governors of affected States and publish the notice of its availability in the FEDERAL REGISTER. The proposed notice of sale references or provides a link to the lease form, and contains a description of the area proposed for leasing, the proposed lease terms and conditions of sale, and proposed stipulations to mitigate potential adverse impacts on the environment.

§ 556.305 How does BOEM coordinate and consult with States regarding a proposed notice of sale?

(a) Within 60 days after receiving the proposed notice of sale, governors of affected States may submit comments and recommendations to BOEM regarding the size, timing, and location of the proposed sale. Local governments may comment to BOEM directly, but must also send their comments to the governor of their State.

(b) BOEM will provide a consistency determination under the Coastal Zone Management Act (CZMA) (16 U.S.C. 1456) to each State with an approved coastal zone management program that will determine whether the proposed sale is consistent, to the maximum extent practicable, with the enforceable policies of the State's approved coastal zone management program.

§ 556.306 What if a potentially oil- or gas-bearing area underlies both the OCS and lands subject to State jurisdiction?

(a) Whenever the Director or the governor of a coastal State determines that a common potentially hydrocarbon-bearing area may underlie the Federal OCS and State submerged lands, the Director or the governor will notify the other party in writing of the determination.

(b) Thereafter the Director will provide to the governor of the coastal State, subject to the confidentiality requirements in this chapter:

(1) An identification of the areas proposed for leasing and a schedule for, leasing; and

(2) An estimate of the oil and gas resources.

(c) At the request of the governor of the coastal State, the Director will provide to such governor, subject to the confidentiality requirements in this chapter:

(1) All geographical, geological, and ecological characteristics of the areas proposed for leasing; and

(2) An identification of any field, geological structure, or trap that lies within 3 miles of the State's seaward boundary.

(d) If BOEM intends to lease such blocks or tracts, the Director and the governor of the coastal State may enter into an agreement for the equitable disposition of the revenues from production of any common potentially hydrocarbon-bearing area, pursuant to OCSLA section 8(g)(3) (43 U.S.C. 1337(g)(3)). Any revenues received by the United States under such an agreement are subject to the requirements

of OSCLA section 8(g)(2) (43 U.S.C. 1337(g)(2)).

(e) If the Director and the governor do not enter into an agreement under paragraph (d) of this section within 90 days, BOEM may nevertheless proceed with the leasing of the tracts, in which case all revenues will be deposited in a separate account in the Treasury of the United States, pending disposition of 27% (twenty-seven percent) of the revenues to the relevant coastal state(s), pursuant to the requirements of OCSLA section 8(g)(2). (43 U.S.C. 1337(g)(2)).

§ 556.307 What does BOEM do with comments and recommendations received on the proposed notice of sale?

(a) BOEM will consider all comments and recommendations received in response to the proposed notice of sale.

(b) If the Secretary determines, after providing opportunity for consultation, that a governor's comments, and those of any affected local government, provide a reasonable balance between the national interest and the well-being of the citizens of the State, the Secretary will accept the recommendations of a State and/or local government(s). Any such determination of the national interest will be based on the findings, purposes and policies of the Act set forth in 43 U.S.C. 1332 and 43 U.S.C. 1801.

(c) BOEM will send to each governor written reasons for its determination to accept or reject each governor's recommendation, and/or to implement any alternative means to provide for a reasonable balance between the national interest and the interests of the citizens of the State.

§ 556.308 How does BOEM conduct a lease sale?

(a) BOEM publishes a final notice of sale in the FEDERAL REGISTER and in other publications, as appropriate, at least 30 days before the date of the sale. The final notice:

(1) States the place, time, and method for filing bids and the place, date, and hour for opening bids; and

(2) Contains or references a description of the areas offered for lease, the lease terms and conditions of sale, and stipulations to mitigate potential adverse impacts on the environment.

(b) Oil and gas tracts are offered for lease by competitive sealed bid in accordance with the terms and conditions in the final notice of sale and applicable laws and regulations.

(c) Unless BOEM finds that a larger area is necessary for reasonable economic production, no individual tract for oil and gas leasing will exceed 5,760 acres in area. If BOEM finds that an area larger than 5,760 acres is necessary in any particular area, the size of any such tract will be specified in the final notice of sale.

(d) The final notice of sale references, or provides a link to, the OCS lease form which will be issued to successful bidders.

§ 556.309 Does BOEM offer blocks in a sale that is not on the Five Year program schedule (called a Supplemental Sale)?

(a) Except as provided in paragraph (c) of this section, BOEM may offer a block within a planning area included in the Five Year program in an otherwise unscheduled sale, if the block:

(1) Received a bid that was rejected in an earlier sale;

(2) Had a high bid that was forfeited in a scheduled sale; or

(3) Is a development block subject to drainage.

(b) For an unscheduled sale, BOEM may disclose the classification of the block as a development block.

(c) Blocks in the Central or Western Gulf of Mexico Planning Areas cannot be offered in a sale that is not on the schedule.

Subpart D—Qualifications

§ 556.400 When must I demonstrate that I am qualified to hold a lease on the OCS?

In order to bid on, own, hold, or operate a lease on the OCS, bidders, record title holders, and operating rights owners must first obtain a qualification number from BOEM.

§ 556.401 What do I need to show to become qualified to hold a lease on the OCS and obtain a qualification number?

(a) You may become qualified to hold a lease on the OCS and obtain a qualification number in accordance with § 556.402, if you submit evidence demonstrating that you are:

(1) A natural person who is a citizen or national of the United States;

(2) A natural person who is an alien lawfully admitted for permanent residence in the United States, as defined in 8 U.S.C. 1101(a)(20);

(3) A private, public, or municipal corporation or Limited Liability Company or Limited Liability Corporation (either/both sometimes herein referred to as ''LLC'') organized under the laws of any State of the United States, the District of Columbia, or any territory or insular possession subject to United States jurisdiction;

(4) An association of such citizens, nationals, resident aliens, or corporations;

(5) A State, the District of Columbia, or any territory or insular possession subject to United States jurisdiction;

(6) A political subdivision of a State, the District of Columbia, or any territory or insular possession subject to United States jurisdiction; or

(7) A Trust organized under the laws of any State of the United States, the District of Columbia, or any territory or insular possession subject to United States jurisdiction;

(b) Statements and evidence submitted to demonstrate qualification under paragraphs (a)(1) through (6) of this section are subject to the penalties of 18 U.S.C. 1001.

(b) BOEM may issue you a qualification number after you have provided evidence acceptable to BOEM.

§ 556.402 How do I make the necessary showing to qualify and obtain a qualification number?

(a) If BOEM has already issued you a qualification number, you may present that number to BOEM. If not, in order to become qualified, you must provide the information in paragraph (b) or (c) of this section before BOEM will issue you a BOEM qualification number.

(b) A natural person must be a citizen or national of the United States, or a resident alien, to qualify. A United States citizen or national must submit written evidence acceptable to BOEM attesting to United States citizenship or national status. A resident alien must submit an original or a photocopy of the United States Citizenship and Immigration Services form evidencing legal status as a resident alien.

(c) A person who is not a natural person must submit evidence (refer to paragraph (d) of this section) acceptable to BOEM that:

(1) It is authorized to conduct business under the laws of a State, the District of Columbia, or any territory or insular possession subject to United States jurisdiction under which it is organized;

(2) Under the operating rules of its business, it is authorized to hold OCS leases; and

(3) Includes an up-to-date list of persons, and their titles, who are authorized to bind the corporation, association or other entity when conducting business on the OCS. It is up to you, in accordance with your organizational structure or rules, to identify the individual, or group of individuals, who has actual authority to bind your organization, and the title(s) they will use when they sign documents to bind the organization. You must maintain and regularly update the information as to who has the authority to bind the organization whenever that information changes.

(d) Acceptable evidence under paragraph (c) of this section includes, but is not limited to:

(1) For a corporation,

(i) A statement by the Secretary of the corporation, over corporate seal, certifying that the corporation is authorized to hold OCS leases; and

(ii) Evidence of authority of holders of positions entitled to bind the corporation, certified by Secretary of the corporation, over corporate seal, such as:

(A) Certified copy of resolution of the board of directors with titles of officers authorized to bind corporation;

(B) Certified copy of resolutions granting corporate officer authority to issue a power of attorney; or

(C) Certified copy of power of attorney or certified copy of resolution granting power of attorney.

(2) For a Limited or General Partnership,

(i) A statement by an authorized party certifying that the partnership is authorized to hold OCS leases;

(ii) A copy of your signed partnership formation documents, including a partnership agreement;

(iii) A statement from each partner indicating, as appropriate, U.S. citizenship or incorporation or organization under the laws of a State, the District of Columbia, or any territory or insular possession subject to U.S. jurisdiction; and

(iv) Documentation evidencing the existence of the partnership and that it was properly created, either from the Secretary of State of the State in which the partnership is registered or by an equivalent State or governmental office.

(3) For a Limited Liability Company or Limited Liability Corporation,

(i) A certificate of formation of the LLC;

(ii) A statement by an individual authorized to bind the LLC, as listed under (c)(4) above, certifying that the LLC is authorized to hold OCS leases;

(iii) A statement from each member indicating, as appropriate, U.S. citizenship, or incorporation or organization under the laws of a State, the District of Columbia, or any territory or insular possession subject to U.S. jurisdiction; and

(iv) Evidence of authority of holders of positions entitled to bind the LLC, certified by an individual authorized to bind the LLC.

(4) For a Trust,

(i) A copy of the trust agreement or document establishing the trust and all amendments, properly certified by the trustee; and

(ii) A statement indicating the law under which the trust is established and that the trust is authorized to hold OCS leases.

(e) In the event that a person may be eligible to hold OCS leases, but that type of person is not listed in paragraphs (c) or (d) of this section, evidence of such eligibility will be submitted and certified by the highest level of management of the person authorized to do so pursuant to its operating agreement or governance documents.

(f) Any person who obtains a qualification number from BOEM is responsible to ensure that it is not using the qualification number approved by BOEM for any purpose that its operating rules do not allow.

(g) Any evidence submitted in response to paragraphs (c), (d), or (e) of this section is submitted subject to 18 U.S.C. 1001.

(h) A person may not hold leases on the OCS until the evidence requested in this section has been accepted and approved by BOEM and BOEM has issued a qualification number to that person.

(i) If use of a corporate seal is required by this section, you may meet the requirement as specified in § 556.107.

§ 556.403 Under what circumstances may I be disqualified from acquiring a lease or an interest in a lease on the OCS?

You may be disqualified from acquiring a lease or an interest in a lease on the OCS if:

(a) You or your principals are excluded or disqualified from participating in a transaction covered by Federal non-procurement debarment and suspension (2 CFR parts 180 and 1400), unless the Department explicitly approves an exception for a transaction pursuant to the regulations in those parts;

(b) The Secretary finds, after notice and hearing, that you or your principals (including in the meaning of ''you,'' for purposes of this subparagraph, a bidder or prospective bidder) fail to meet due diligence requirements or to exercise due diligence under section 8(d) of OCSLA (43 U.S.C. 1337(d)) on any OCS lease; or

(c) BOEM disqualifies you from acquiring a lease or an interest in a lease on the OCS based on your unacceptable operating performance. BOEM will give you adequate notice and opportunity for a hearing before imposing a disqualification, unless BSEE has already provided such notice and opportunity for a hearing.

[81 FR 34275, May 31, 2016]

§ 556.404 What do the non-procurement debarment rules require that I do?

You must comply with the Department's non-procurement debarment regulations at 2 CFR parts 180 and 1400.

(a) You must notify BOEM if you know that you or your principals are excluded, disqualified, have been convicted or are indicted of a crime as described in 2 CFR part 180, subpart C. You must make this notification before you sign a lease, sublease, or an assignment of record title interest or operating rights interest, or become a lease or unit operator. This paragraph does not apply if you have previously provided a statement disclosing this information, and you have received an exception from the Department, as described in 2 CFR 180.135 and 2 CFR 1400.137.

(b) If you wish to enter into a covered transaction with another person at a lower tier, as described in 2 CFR 180.200, you must first:

(1) Verify that the person is not excluded or disqualified under 2 CFR part 180; and

(2) Require the person to:

(i) Comply with 2 CFR part 180, subpart C; and

(ii) Include the obligation to comply with 2 CFR part 180, subpart C in its contracts and other transactions.

(c) After you enter into a covered transaction, you must immediately notify BOEM in writing if you learn that:

(1) You failed to disclose pertinent information earlier; or

(2) Due to changed circumstances, you or your principals now meet any of the criteria in 2 CFR 180.800.

§ 556.405 When must I notify BOEM of mergers, name changes, or changes of business form?

You must notify BOEM of any merger, name change, or change of business form as soon as practicable, but in no case later than one year after the earlier of the effective date or the date of filing the change or action with the Secretary of State or other authorized official in the State of original registry.

Subpart E—Issuance of a Lease

HOW TO BID

§ 556.500 Once qualified, how do I submit a bid?

(a) You must submit a separate sealed bid for each tract or bidding unit to the address provided and by the time specified in the final notice of sale. You may not bid on less than an entire tract or bidding unit.

(b) BOEM requires a deposit for each bid. The final notice of sale will specify the amount and method of payment.

(c) Unless otherwise specified in the final notice of sale, the bid deposit amount will be 20 percent of the amount of the bid for any given tract or bidding unit.

(d) You may not submit a bid on an OCS tract if, after notice and hearing under section 8(d) of OCSLA (43 U.S.C. 1337(d)), the Secretary finds that you are not meeting the diligence requirements on any OCS lease.

(e) If the authorized officer within BOEM rejects your high bid, the decision is final for the Department, subject only to reconsideration upon your written request as set out in § 556.517.

§ 556.501 What information do I need to submit with my bid?

In accordance with OCSLA section 18(a)(4) (43 U.S.C. 1344(a)(4)), BOEM must evaluate every bid to ensure that the federal government receives fair market value for every lease. Section 26(a)(1)(A) of OCSLA (43 U.S.C. 1352(a)(1)(A)) provides that, in accordance with regulations prescribed by the Secretary, any lessee or permittee conducting any exploration for, or development or production of, oil or gas must provide the Secretary access to all data and information (including processed, analyzed, and interpreted information) obtained from that activity and must provide copies of that data and information as the Secretary may request.

(a) As part of the lease sale process, every bidder submitting a bid on a tract, or participating as a joint bidder in such a bid, may at the time of bid be required to submit various information, including a Geophysical Data and

Information Statement (GDIS) corresponding to that tract, as well as the bidder's exclusive/proprietary geophysical data in order for BOEM to properly evaluate the bid. If a GDIS required, each GDIS must include, as required by § 551.12(b) and (c) of this chapter:

(1) A list of geophysical surveys or other information used as part of the decision to bid or participate in a bid on the block.

(2) An accurate and complete record of each geophysical survey conducted, including digital navigational data and final location maps. The bidder and any joint bidder must include a map for each survey identified in the GDIS that illustrates the actual areal extent of the proprietary geophysical data.

(b) If a bidder is required to submit a GDIS, the GDIS must be submitted even if the bidder did not rely on proprietary geophysical data and information in deciding to bid or participate as a joint bidder in the bid for any particular block, and must include entries for all such blocks.

(c) The bidder must submit each GDIS in a separate and sealed envelope, or in an electronically readable spreadsheet format, with proprietary seismic data maps also available in an electronic format. Each bidder must submit the GDIS even if its joint bidder or bidders on a specific block also have submitted a GDIS.

(d) If BOEM requires additional information related to bidding, it will describe the additional information requirements in the final notice of sale.

(e) BOEM will reimburse bidders for the costs of complying with the requirements of this section, in accordance with § 550.196 (on lease) and/or § 551.13 (off lease) of this chapter.

(f) Bids that are not made in compliance with this section will be considered incomplete and invalid.

RESTRICTIONS ON JOINT BIDDING

§ 556.511 Are there restrictions on bidding with others and do those restrictions affect my ability to bid?

The Energy Policy and Conservation Act of 1975, 42 U.S.C. 6213, prohibits joint bidding by major oil and gas producers under certain circumstances. BOEM implements 42 U.S.C. 6213 as follows:

(a) BOEM publishes twice yearly in the FEDERAL REGISTER a restricted joint bidders list. A person appearing on this list is limited in its ability to submit a joint bid. The list:

(1) Consists of the persons chargeable with an average worldwide daily production in excess of 1.6 million barrels of crude oil and/or its equivalent in natural gas liquids and natural gas for the prior production period; and

(2) Is based upon the statement of production that filed as required by § 556.513.

(b) If BOEM places you on the restricted joint bidders list, BOEM will send you a copy of the order placing you on the list. You may appeal this order to the Interior Board of Land Appeals under 30 CFR part 590, subpart A.

(c) If you are listed in the FEDERAL REGISTER in any group of restricted bidders, you may not bid:

(1) Jointly with another person in any other group of restricted bidders for the applicable 6-month bidding period; or

(2) Separately during the 6-month bidding period if you have an agreement with another restricted bidder that will result in joint ownership in an OCS lease.

(d) If you are listed in the FEDERAL REGISTER in any group of restricted bidders, you may not make any pre-bidding agreement for the conveyance of any potential lease interest, whether by assignment, sale, transfer, or other means, to any person on the list of restricted joint bidders.

(e) Even if you are not listed in the FEDERAL REGISTER in any group of restricted bidders, you are prohibited from making any pre-bidding agreement for the assignment, sale, transfer, or other conveyance of any potential lease interest to two or more persons in different groups on the list of restricted joint bidders.

(f) As a bidder, you are prohibited from unlawful combination with, or intimidation of, bidders under 18 U.S.C. 1860.

§ 556.512 What bids may be disqualified?

The following bids for any oil and gas lease will be disqualified and rejected in their entirety:

(a) A joint bid submitted by two or more persons who are on the effective List of Restricted Joint Bidders; or

(b) A joint bid submitted by two or more persons when:

(1) One 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 natural gas liquids and has not filed a Statement of Production, as required by § 556.513 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 § 556.513, 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) that 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 two 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 natural gas liquids and has not filed a Statement of Production pursuant to § 556.513 for the applicable six-month bidding period. Assignments expressly required by law, regulation, lease or lease stipulation will 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.

§ 556.513 When must I file a statement of production?

(a) You must file a statement of production if your average worldwide daily production exceeded 1.6 million barrels for the prior production period, as determined using the method set forth in § 556.514. Your statement of production must specify that you were chargeable with an average daily production in excess of 1.6 million barrels for the prior production period.

(b) The prior production periods are as follows:

For the bidding period of	The prior production period is the preceding
(1) May through October	July through December.
(2) November through April ...	January through June.

(c) You must file the statement of production by the following deadlines:

For the bidding period of	You must file the statement by
(1) May through October	March 17.
(2) November through April ...	September 17.

(d) If you are required to file a statement of production, BOEM may require you to submit a detailed report of production.

(1) The detailed report of production must list crude oil, natural gas liquids, and natural gas produced worldwide from reservoirs during the prior production period, and therefore chargeable to the prior production period.

(i) The amount of crude oil chargeable to the prior production period will 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 net differences between opening and closing inventories, and basic sediment and water.

(ii) The amount of natural gas liquids chargeable to the prior production period must include gas liquefied at surface separators, field facilities, or gas processing plants.

(iii) The amount of natural gas chargeable to the prior production period must include adjustments, where applicable, to reflect the volume of gas returned to natural reservoirs, and the reduction of volume resulting from the removal of natural gas liquids and non-hydrocarbon gases.

(2) You must submit the detailed report of production within 30 days after receiving BOEM's request.

(3) BOEM may inspect and copy any document, record of production, analysis, and other material to verify the accuracy of any earlier statement of production.

(e) If you submit a statement of production that misrepresents your chargeable production, the Department may cancel any lease awarded in reliance upon the statement.

§ 556.514 How do I determine my production for purposes of the restricted joint bidders list?

(a) To determine the amount of production chargeable to you, add together:

(1) Your average daily production in barrels of crude oil, natural gas liquids, and natural gas worldwide, all measured at 60 °F, using the equivalency or conversion factors for natural gas liquids and natural gas set out in 42 U.S.C. 6213(b)(2) and (3); and

(2) Your proportionate share of the average daily production owned by any person that has an interest in you and/or in which you have an interest.

(b) For the purpose of paragraph (a)(1) of this section, your production includes 100 percent of production owned by:

(1) You;

(2) Every subsidiary of yours;

(3) Every person of which you are a subsidiary; and

(4) Every subsidiary of any person of which you are a subsidiary.

(c) For purposes of paragraph (a)(2) of this section, interest means at least a five percent ownership or control of you or the reporting person and includes any interest:

(1) From ownership of securities or other evidence of ownership; or,

(2) By participation in any contract, agreement, or understanding regarding control of the person or their production of crude oil, natural gas liquids, or natural gas.

(d) For purposes of this section, subsidiary means a person, 50 percent or more of whose stock or other interest having power to vote for the election of a controlling body, such as directors or trustees, is directly or indirectly owned or controlled by another person.

(e) For purposes of this section, production chargeable to you includes, but is not limited to, production obtained as a result of a production payment or a working, net profit, royalty, overriding royalty, or carried interest.

(f) For purposes of this section, production must be measured with appropriate adjustments for:

(1) Basic sediment and water;

(2) Removal of natural gas liquids and non-hydrocarbon gases; and

(3) Volume of gas returned to natural reservoirs.

§ 556.515 May a person be exempted from joint bidding restrictions?

BOEM may exempt you from some or all of the reporting requirements listed in § 556.513, and/or some or all of the joint bidding restrictions listed in §§ 556.511 and/or 556.512(a), (b), and/or (c), if, after opportunity for a hearing, BOEM determines that the extremely high costs in an area will preclude exploration and development without an exemption.

How Does BOEM Act on Bids?

§ 556.516 What does BOEM do with my bid?

(a) BOEM opens the sealed bids at the place, date, and hour specified in the final notice of sale for the sole purpose

of publicly announcing and recording the bids. BOEM does not accept or reject any bids at that time.

(b) BOEM reserves the right to reject any and all bids received, regardless of the amount offered. BOEM accepts or rejects all bids within 90 days of opening. BOEM reserves the right to extend that time if necessary, and in that event, BOEM will notify bidder(s) in writing prior to the expiration of the initial 90-day period, or of any extension. Any bid not accepted within the prescribed 90-day period, or any extension thereof, will be deemed rejected. If your bid is rejected, BOEM will refund any money deposited with your bid, plus any interest accrued.

(c) If the highest bids are a tie, BOEM will notify the bidders who submitted the tie bids. Within 15 days after notification, those bidders, if qualified, and not otherwise prohibited from bidding together, may:

(1) Agree to accept the lease jointly. The bidders must notify BOEM of their decision and submit a copy of their agreement to accept the lease jointly.

(2) Agree between/among themselves which bidder will accept the lease. The bidders must notify BOEM of their decision.

(d) If no agreement is submitted pursuant to paragraph (c) of this section, BOEM will reject all the tie bids.

(e) The Attorney General, in consultation with the Federal Trade Commission, has 30 days to review the results of the lease sale before BOEM may accept the bid(s) and issue the lease(s).

§ 556.517 What may I do if my high bid is rejected?

(a) The decision of the authorized officer on bids is the final action of the Department, subject only to reconsideration of the rejection of the high bid by the Director, in accordance with paragraph (b) of this section.

(b) Within 15 days of bid rejection, you may file a written request for reconsideration with the Director, with a copy to the authorized officer. Such request must provide evidence as to why the Director should reconsider your bid. You will receive a written response either affirming or reversing the rejection of your bid.

(c) The Director's decision on the request for reconsideration is not subject to appeal to the Interior Board of Land Appeals in the Department's Office of Hearings and Appeals.

AWARDING THE LEASE

§ 556.520 What happens if I am the successful high bidder and BOEM accepts my bid?

(a) If BOEM accepts your bid, BOEM will provide you with the appropriate number of copies of the lease for you to execute and return to BOEM. Within 11 business days after you receive the lease copies, you must:

(1) Execute all copies of the lease;

(2) Pay the first year's rental;

(3) Pay the balance of the bonus bid, unless deferred under paragraph (b) below;

(4) Comply with subpart I of this part; and,

(5) Return all copies of the executed lease, including any required bond or other form of security approved by the Regional Director, to BOEM.

(b) If provided for in the final notice of sale, BOEM may defer any part of the bonus and bid payment for up to five years after the sale according to a schedule included in the final notice of sale. You must provide a bond acceptable to BOEM to guarantee payment of a deferred bonus bid.

(c) If you do not make the required payments and execute and return all copies of the lease and any required bond within 11 business days after receipt, or if you otherwise fail to comply with applicable regulations, your deposit will be forfeited. However, BOEM will return any deposit with interest if the tract is withdrawn from leasing before you execute the lease.

(d) If you use an agent to execute the lease, you must include evidence with the executed copies of the lease that a person who is on the list of persons referenced in § 556.402(c)(3) authorized the agent to act for you.

(e) After you comply with all requirements in this section, and after BOEM has executed the lease, BOEM will send you a fully executed lease.

§ 556.521 When is my lease effective?

Your lease is effective on the first day of the month following the date

that BOEM executes the lease. You may request in writing, before BOEM executes the lease, that your lease be effective as of the first day of the month in which BOEM executes the lease. If BOEM agrees to make the lease effective as of the earlier date, BOEM will so indicate when it executes the lease.

§ 556.522 What are the terms and conditions of the lease and when are they published?

The terms and conditions of the lease will be stated in the final notice of sale and contained in the lease instrument itself. Oil and gas leases and leases for sulfur will be issued on forms approved by the Director.

Subpart F—Lease Term and Obligations

LENGTH OF LEASE

§ 556.600 What is the primary term of my oil and gas lease?

(a) The primary term of an oil and gas lease will be five years, unless BOEM determines that:

(1) The lease is located in unusually deep water or involves other unusually adverse conditions; and,

(2) A lease term longer than five years is necessary to explore and develop the lease.

(b) If BOEM determines that the criteria in paragraphs (a)(1) and (2) of this section are met, it may specify a longer primary term, not to exceed 10 years.

(c) BOEM will specify the primary term in the final notice of sale and in the lease instrument.

(d) The lease will expire at the end of the primary term, unless maintained beyond that term in accordance with the provisions of § 556.601.

§ 556.601 How may I maintain my oil and gas lease beyond the primary term?

You may maintain your oil and gas lease beyond the expiration of the primary term as long as:

(a) You are producing oil or gas in paying quantities;

(b) You are conducting approved drilling or well reworking operations with the objective of establishing production in paying quantities, in accordance with 30 CFR 250.180;

(c) You are producing from, or drilling or reworking, an approved well adjacent to or adjoining your lease that extends directionally into your lease in accordance with 30 CFR 256.71;

(d) You make compensatory payments on your lease in accordance with 30 CFR 256.72;

(e) Your lease is included in a BSEE-approved unit, in accordance with 30 CFR part 250, subpart M; or

(f) Your lease is subject to a suspension of production or a suspension of operations, in accordance with 30 CFR 250.168 through 250.180, for reasons other than gross negligence or a willful violation of a provision of your lease or any governing regulations.

§ 556.602 What is the primary term of my sulfur lease?

(a) Your sulfur lease will have a primary term of not more than 10 years, as specified in the lease.

(b) BOEM will announce the primary term prior to the lease sale.

(c) The lease will expire at the end of the primary term unless maintained beyond that term in accordance with the provisions of § 556.603.

§ 556.603 How may I maintain my sulfur lease beyond the primary term?

You may maintain your sulfur lease after the primary term as long as you are producing sulfur in paying quantities, conducting drilling, well reworking or plant construction, or other operations for the production of sulfur or you are granted a suspension by BSEE; or your lease is subject to a suspension directed by BSEE for reasons other than gross negligence or a willful violation of a provision of your lease or governing regulations.

LEASE OBLIGATIONS

§ 556.604 What are my rights and obligations as a record title owner?

(a) As a record title owner, you are responsible for all administrative and operating performance on the lease, including paying any rent and royalty due.

(b)(1) A record title owner owns operating rights to the lease, unless and until he or she severs the operating rights by subleasing them to someone else.

(2) A sublease of operating rights from record title may be for a whole or undivided fractional interest in the entire lease or a described aliquot portion of the lease and/or a depth interval. The sublease creates an operating rights interest in the sublessee, herein referred to as the operating rights owner.

(c) Within any given aliquot, the record title owner may sublease operating rights for up to a maximum of two depth divisions, which may result in a maximum of three different depth intervals. But, if the one, or two, depth divisions to which operating rights are subleased do not include the entire depth of the lease, whatever depth division(s) has not been subleased, remains part of the lessee/sublessor's record title interest. The depth intervals for which operating rights are subleased must be defined by a beginning and ending depth and the ending of one depth level must abut the beginning of the next depth level, with no gap in between.

(d) Every current and prior record title owner is jointly and severally liable, along with all other record title owners and all prior and current operating rights owners, for compliance with all non-monetary terms and conditions of the lease and all regulations issued under OCSLA, as well as for fulfilling all non-monetary obligations, including decommissioning obligations, which accrue while it holds record title interest.

(e) Record title owners that acquired their record title interests through assignment from a prior record title owner are also responsible for remedying all existing environmental or operational problems on any lease in which they own record title interests, with subrogation rights against prior lessees.

(f) For monetary obligations, your obligation depends on the source of the monetary obligation and whether you have retained or severed your operating rights.

(1) With respect to those operating rights that you have retained, you are primarily liable under 30 U.S.C. 1712(a) for your pro-rata share of all other monetary obligations pertaining to that portion of the lease subject to the operating rights you have retained, based on your share of operating rights in that portion of the lease.

(2) With respect to all monetary obligations arising from or in connection with those operating rights that have been severed from your record title interest, your obligation is secondary to that of the sublessee(s) or later assignee(s) of the operating rights that were severed from your record title interest, as prescribed in 30 U.S.C. 1712(a).

§ 556.605 What are my rights and obligations as an operating rights owner?

(a) As an operating rights owner, you have the right to enter the leased area to explore for, develop, and produce oil and gas resources, except helium gas, contained within the aliquot(s) and depths within which you own operating rights, according to the lease terms, applicable regulations, and BOEM's approval of the sublease or subsequent assignment of the operating rights.

(b) Unless otherwise prohibited, you have the right to authorize another party to conduct operations on the part of the lease to which your operating rights appertain.

(c) An owner of operating rights who is designating a new designated operator must file a designation of operator under § 550.143 of this chapter.

(d) An operating rights owner is only liable for obligations arising from that portion of the lease to which its operating rights appertain and that accrue during the period in which the operating rights owner owned the operating rights.

(e) You are jointly and severally liable with other operating rights owners and the record title owners for all non-monetary lease obligations pertaining to that portion of the lease subject to your operating rights, which accrued during the time you held your operating rights interest.

(f) An operating rights owner that acquires its operating rights interests

through assignment from a prior operating rights owner is also responsible, with subrogation rights against prior operating rights owners, for remedying existing environmental or operational problems, to the extent that such problems arise from that portion of the lease to which its operating rights appertain, on any lease in which it owns operating rights.

(g) You are primarily liable for monetary obligations pertaining to that portion of the lease subject to your operating rights, and the record title owners are secondarily liable. If there is more than one operating rights owner in a lease, each operating rights owner is primarily liable for its prorata share of the monetary obligations that pertain to the portion of the lease that is subject to its operating rights.

HELIUM

§ 556.606 What must a lessee do if BOEM elects to extract helium from a lease?

(a) BOEM reserves the ownership of, and the right to extract, helium from all gas produced from your OCS lease. Under section 12(f) of OCSLA (43 U.S.C. 1341(f)), upon our request, you must deliver all or a specified portion of the gas containing helium to BOEM at a point on the leased area or at an onshore processing facility that BOEM designates.

(b) BOEM will determine reasonable compensation and pay you for any loss caused by the extraction of helium, except for the value of the helium itself. BOEM may erect, maintain, and operate on your lease any reduction work and other equipment necessary for helium extraction. Our extraction of helium will be conducted in a manner to not cause substantial delays in the delivery of gas to your purchaser.

Subpart G—Transferring All or Part of the Record Title Interest in a Lease

§ 556.700 May I assign or sublease all or any part of the record title interest in my lease?

(a) With BOEM approval, you may assign your whole, or a partial record title interest in your entire lease, or in any aliquot(s) thereof.

(b) With BOEM approval, you may sever all, or a portion of, your operating rights.

(c) You must request approval of each assignment of a record title interest and each sublease of an operating rights interest. Each instrument that transfers a record title interest must describe, by aliquot parts, the interest you propose to transfer. Each instrument that severs an operating rights interest must describe, by officially designated aliquot parts and depth levels, the interest proposed to be transferred.

§ 556.701 How do I seek approval of an assignment of the record title interest in my lease, or a severance of operating rights from that record title interest?

(a) The Regional Director will provide the form to record an assignment of record title interest in a Federal OCS oil and gas or sulfur lease, or a severance of operating rights from that record title interest. You must submit to BOEM two originals of each instrument that transfers ownership of record title within 90 days after the last party executes the transfer instrument. You must pay the service fee listed in § 556.106 with your request and your submission must include evidence of payment via *pay.gov*.

(b) Before BOEM approves an assignment or transfer, it must consult with, and consider the views of, the Attorney General. The Secretary may act on an assignment or transfer if the Attorney General has not responded to a request for consultation within 30 days of said request.

(c) A new record title owner or sublessee must file a designation of operator, in accordance with § 550.143 of this chapter, along with the request for the approval of the assignment.

§ 556.702 When will my assignment result in a segregated lease?

(a) When there is an assignment by all record title owners of 100 percent of the record title to one or more aliquots in a lease, the assigned and retained portions become segregated into separate and distinct leases. In such case, both the new lease and the remaining

portion of the original lease are referred to as ''segregated leases'' and the assignee(s) becomes the record title owner(s) of the new lease, which is subject to all the terms and conditions of the original lease.

(b) If a record title holder transfers an undivided interest, *i.e.*, less than 100 percent of the record title interest in any given aliquot(s), that transfer will not segregate the portions of the aliquots, or the whole aliquots, in which part of the record title was transferred, into separate leases from the portion(s) in which no interest was transferred. Instead, that transfer will create a joint ownership between the assignee(s) and assignor(s) in the portions of the lease in which part of the record title interest was transferred. Any transfer of an undivided interest is subject to approval by BOEM.

§ 556.703 What is the effect of the approval of the assignment of 100 percent of the record title in a particular aliquot(s) of my lease and of the resulting lease segregation?

(a) The bonding/financial assurance requirements of subpart I of this part apply separately to each segregated lease.

(b) The royalty, minimum royalty, and rental provisions of the original lease will apply separately to each segregated lease.

(c) BOEM will allocate among the segregated leases, on a basis that is equitable under the circumstances, any remaining unused royalty suspension volume or other form of royalty suspension or royalty relief that had been granted to the original lease, not to exceed in aggregate the total remaining amount.

(d) Each segregated lease will continue in full force and effect for the primary term of the original lease and so long thereafter as each segregated lease meets the requirements outlined in § 556.601. A segregated lease that does not meet the requirements of § 556.601 does not continue in force even if another segregated lease, which was part of the original lease, continues to meet those requirements.

§ 556.704 When would BOEM disapprove an assignment or sublease of an interest in my lease?

(a) BOEM may disapprove an assignment or sublease of all or part of your lease interest(s):

(1) When the transferor or transferee has unsatisfied obligations under this chapter or 30 CFR chapters II or XII;

(2) When a transferor attempts a transfer that is not acceptable as to form or content (e.g., not on standard form, containing incorrect legal description, not executed by a person authorized to bind the corporation, transferee does not meet the requirements of § 556.401, etc.); or,

(3) When the transfer does not conform to these regulations, or any other applicable laws or regulations (e.g., departmental debarment rules).

(b) A transfer will be void if it is made pursuant to any prelease agreement that would cause a bid to be disqualified, such as those described in § 556.511(c), (d), or (e).

§ 556.705 How do I transfer the interest of a deceased natural person who was a lessee?

(a) An heir or devisee must submit evidence by means of a certified copy of an appropriate court order or decree that the person is deceased; or, if no court action is necessary, a certified copy of the will and death certificate or notarized affidavits of two disinterested parties with knowledge of the facts.

(b) The heir or devisee, if the lawful successor in interest, must submit evidence that he/she is the person named in the will or evidence from an appropriate judgment of a court or decree that he/she is the lawful successor in interest, along with the required evidence of his/her qualifications to hold a lease under subpart D of this part.

(c) If the heir or devisee does not qualify to hold a lease under subpart D of this part, he/she will be recognized as the successor in interest, but he/she must divest him/herself of this interest in the lease, to a person qualified to be a hold a lease, within two years.

§ 556.706 What if I want to transfer record title interests in more than one lease at the same time, but to different parties?

You may not transfer interests in more than one lease to different parties using the same instrument. If you want to transfer the interest in more than one lease at the same time, you must submit duplicate, originally executed forms for each transfer. The forms used for each transfer must be accompanied by a cover letter executed by one of the parties to the transfer (or an authorized agent thereof) and evidence of payment via *pay.gov*.

§ 556.707 What if I want to transfer different types of lease interests (not only record title interests) in the same lease to different parties?

You may not transfer different types of lease interests in a lease to different parties using the same instrument. You must submit duplicate, originally executed forms for each transfer, to a different party, of a different type of lease interest. The form used to transfer each type of lease interest must be accompanied by a cover letter executed by one of the parties to the transfer (or an authorized agent thereof) and evidence of payment via *pay.gov*.

§ 556.708 What if I want to transfer my record title interests in more than one lease to the same party?

You may not transfer your record title interests in more than one lease to the same party using the same instrument. If you want to transfer record title interests in more than one lease at the same time, you must submit separate, originally executed forms for each transfer. The forms used for each transfer must be accompanied by a cover letter executed by one of the parties to the transfer (or an authorized agent thereof), and evidence of payment via *pay.gov*. A separate fee applies to each individual transfer of interest.

§ 556.709 What if I want to transfer my record title interest in one lease to multiple parties?

You may transfer your record title interest in one lease to multiple parties using the same instrument. That instrument must be submitted in duplicate originals, accompanied by a cover letter executed by one of the parties to the transfer (or an authorized agent thereof). In such a multiple transfer of interests using a single instrument, a separate fee applies to each individual transfer of interest, and evidence of payment via *pay.gov* must accompany the instrument.

§ 556.710 What is the effect of an assignment of a lease on an assignor's liability under the lease?

If you assign your record title interest, as an assignor you remain liable for all obligations, monetary and nonmonetary, that accrued in connection with your lease during the period in which you owned the record title interest, up to the date BOEM approves your assignment. BOEM's approval of the assignment does not relieve you of these accrued obligations. Even after assignment, BOEM or BSEE may require you to bring the lease into compliance if your assignee or any subsequent assignee fails to perform any obligation under the lease, to the extent the obligation accrued before approval of your assignment. Until there is a BOEM-approved assignment of interest, you, as the assignor, remain liable for the performance of all lease obligations that accrued while you held record title interest, until all such obligations are fulfilled.

§ 556.711 What is the effect of a record title holder's sublease of operating rights on the record title holder's liability?

(a) A record title holder who subleases operating rights remains liable for all obligations of the lease, including those obligations accruing after BOEM's approval of the sublease, subject to § 556.604(e) and (f).

(b) Neither the sublease of operating rights, nor subsequent assignment of those rights by the original sublessee, nor by any subsequent assignee of the operating rights, alters in any manner the liability of the record title holder for nonmonetary obligations.

(c) Upon approval of the sublease of the operating rights, the sublessee and subsequent assignees of the operating rights become primarily liable for monetary obligations, but the record title holder remains secondarily liable

for them, as prescribed in 30 U.S.C. 1712(a) and § 556.604(f)(2).

§ 556.712 What is the effective date of a transfer?

Any transfer is effective at 12:01 a.m. on the first day of the month following the date on which BOEM approves your request, unless you request an earlier effective date and BOEM approves that earlier date, but such earlier effective date, if prior to the date of BOEM's approval, does not relieve you of obligations accrued between that earlier effective date and the date of approval.

§ 556.713 What is the effect of an assignment of a lease on an assignee's liability under the lease?

As assignee, you and any subsequent assignees are liable for all obligations that accrue after the effective date of your assignment. As assignee, you must comply with all the terms and conditions of the lease and regulations issued under OCSLA, and in addition, you must remedy all existing environmental and operational problems on the lease, properly abandon all wells, and reclaim the site, as required under 30 CFR part 250.

§ 556.714 As a restricted joint bidder, may I transfer an interest to another restricted joint bidder?

(a) 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 held by the assignor or transferor and to a person or persons on the same List of Restricted Joint Bidders, the assignor or transferor must file, prior to the approval of the assignment, a copy of all agreements applicable to the acquisition of that lease or fractional interest, or a description of the timing and nature of the agreement(s) by which the assignor or transferor acquired the interest it now wishes to transfer.

(b) Such description of the timing and nature of the transfer agreement must be submitted together with a certified statement that attests to the truth and accuracy of any information reported concerning that agreement, subject to the penalties of 18 U.S.C. 1001.

(c) If you wish to transfer less than your entire interest to another restricted joint bidder, BOEM may request the opinion of the Attorney General before acting on your request.

(d) You may request that any submission to BOEM made pursuant to this part be treated confidentially. Please note such a request on your submission. BOEM will treat this request for confidentiality in accordance with the regulations at § 556.104 and the regulations at 43 CFR part 2.

§ 556.715 Are there any interests I may transfer or record without BOEM approval?

(a) You may create, transfer, or assign economic interests without BOEM approval. However, for record purposes, you must send BOEM a copy of each instrument creating or transferring such interests within 90 days after the last party executes the transfer instrument. For each lease affected, you must pay the service fee listed in § 556.106 with your documents submitted for record purposes and your submission must include evidence of payment via *pay.gov*.

(b) For recordkeeping purposes, you may also submit other legal documents to BOEM for transactions that do not require BOEM approval. If you submit such documents for record purposes not required by this part, you must pay the service fee listed in § 556.106 with your document submissions for each lease affected. Your submission must include evidence of payment via *pay.gov*.

§ 556.716 What must I do with respect to the designation of operator on a lease when a transfer of record title is submitted?

(a) If a transfer of ownership of the record title interest only changes the percentage ownership of the record title, no new parties or new aliquots are involved in the transaction, and no change of designated operator is made, you will not need to submit a new designation of operator form.

(b) In all cases other than that in paragraph (a) of this section, you must submit new designation of operator forms in accordance with § 550.143 of this chapter. In the event that you are

transferring multiple record title interests, you must comply with this requirement for each interest that does not fall within paragraph (a) of this section.

Subpart H—Transferring All or Part of the Operating Rights in a Lease

§ 556.800 As an operating rights owner, may I assign all or part of my operating rights interest?

An operating rights owner may assign all or part of its operating rights interests, subject to BOEM approval. Each instrument that transfers an interest must describe, by officially designated aliquot parts and depth levels, the interest proposed to be transferred.

§ 556.801 How do I seek approval of an assignment of my operating rights?

(a) The Regional Director will provide the form to document the assignment of an operating rights interest. You must request approval of each assignment of operating rights and submit to BOEM two originals of each instrument that transfers ownership of operating rights within 90 days after the last party executes the transfer instrument. You must pay the service fee listed in § 556.106 with your request and your submission must include evidence of payment via *pay.gov*.

(b) A new operating rights owner must file a designation of operator, in accordance with § 550.143, along with the request for the approval of the assignment.

(c) If an operating rights owner assigns an undivided ownership interest in its operating rights, that assignment creates a joint ownership in the operating rights.

(d) Before BOEM approves a sublease or re-assignment of operating rights, BOEM may consult with and consider the views of the Attorney General.

§ 556.802 When would BOEM disapprove the assignment of all or part of my operating rights interest?

BOEM may disapprove an assignment of all or part of your operating rights interest:

(a) When the transferor or transferee has outstanding or unsatisfied obligations under this chapter or 30 CFR chapter II or XII;

(b) When a transferor attempts a transfer that is not acceptable as to form or content (e.g., not on standard form, containing incorrect legal description, not executed in accordance with corporate governance, transferee does not meet the requirements of § 556.401, etc.); or

(c) When the transfer does not conform to these regulations, or any other applicable laws or regulations (e.g., departmental debarment rules).

§ 556.803 What if I want to assign operating rights interests in more than one lease at the same time, but to different parties?

You may not assign operating rights interests in more than one lease to different parties using the same instrument. If you want to transfer operating rights interests in more than one lease at the same time, you must submit two originally executed forms for each transfer. Each request for a transfer of operating rights interest must be accompanied by a cover letter executed by one of the parties to the transfer (or an authorized agent thereof) and evidence of payment via *pay.gov*.

§ 556.804 What if I want to assign my operating rights interest in a lease to multiple parties?

You may assign your operating rights interest in one lease to multiple parties using the same instrument. That instrument must be submitted in duplicate originals, accompanied by a cover letter executed by one of the parties to the transfer (or an authorized agent thereof). In such a multiple transfer of interests using a single instrument, a separate fee applies to each individual transfer of interest and evidence of payment via *pay.gov* must accompany the instrument.

§ 556.805 What is the effect of an operating rights owner's assignment of operating rights on the assignor's liability?

An operating rights owner (who does not hold record title) who assigns the operating rights remains liable for all obligations of the lease that accrued during the period in which the assignor owned the operating rights, up to the

effective date of the assignment, including decommissioning obligations that accrued during that period. BOEM's approval of the assignment does not alter that liability. Even after assignment, BOEM or BSEE may require the assignor to bring the lease into compliance if the assignee or any subsequent assignee fails to perform any obligation under the lease, to the extent the obligation accrued before approval of the assignment.

§ 556.806 What is the effective date of an assignment of operating rights?

An assignment is effective at 12:01 a.m. on the first day of the month following the date on which BOEM approves your request, unless you request an earlier effective date and BOEM approves that earlier date. Such an earlier effective date, if prior to the date of BOEM's approval, does not relieve you of obligations accrued between that earlier effective date and the date of approval.

§ 556.807 What is the effect of an assignment of operating rights on an assignee's liability?

As assignee, you and any subsequent assignees are liable for all obligations that accrue after the effective date of your assignment. As assignee, you must comply with all the terms and conditions of the lease and regulations issued under OCSLA. In addition, you must remedy all existing environmental and operational problems on the lease, properly abandon all wells, and reclaim the site, as required under 30 CFR part 250.

§ 556.808 As an operating rights owner, are there any interests I may assign without BOEM approval?

(a) You may create, transfer, or assign economic interests without BOEM approval. However, for record purposes, you must send BOEM a copy of each instrument creating or transferring such interests within 90 days after the last party executes the transfer instrument. For each lease affected, you must pay the service fee listed in § 556.106 with your documents submitted for record purposes, and your submission must include evidence of payment via *pay.gov*.

(b) For record keeping purposes, you may also submit other legal documents to BOEM for transactions that do not require BOEM approval. If you submit such documents for record purposes that are not required by these regulations, for each lease affected, you must pay the service fee listed in § 556.106 with your document submissions, and your submission must include evidence of payment via *pay.gov*.

§ 556.809 [Reserved]

§ 556.810 What must I do with respect to the designation of operator on a lease when a transfer of operating rights ownership is submitted?

(a) If a transfer of ownership of operating rights only changes the percentage ownership; no new parties, new aliquots, or new depths are involved in the transaction; and no change of designated operator is made, you will not need to submit a new designation of operator form.

(b) In all cases other than that in paragraph (a) of this section, you must submit new designation of operator forms, in accordance with § 550.143 of this chapter. In the event that you are transferring multiple operating rights interests, you must comply with this requirement for each interest that does not fall within paragraph (a) of this section.

Subpart I—Bonding or Other Financial Assurance

§ 556.900 Bond requirements for an oil and gas or sulfur lease.

This section establishes bond requirements for the lessee of an OCS oil and gas or sulfur lease.

(a) Before BOEM 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 area-wide bond that guarantees compliance with all the terms and conditions of all your oil and gas and sulfur leases in the area where the lease is located; or

(3) Maintain a lease or area-wide bond in the amount required in § 556.901(a) or (b).

(b) For the purpose of this section, there are three areas. The three areas are:

(1) The Gulf of Mexico and the area offshore the Atlantic Coast;

(2) The area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; and

(3) The area offshore the Coast of Alaska.

(c) The requirement to maintain a lease bond (or substitute security instrument) under paragraph (a)(1) of this section and § 556.901(a) and (b) may be satisfied if your operator or an operating rights owner provides a lease bond in the required amount that guarantees compliance with all the terms and conditions of the lease. Your operator or an operating rights owner may 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 alternative form of security maintained under this section, the surety's remaining liability under the bond or alternative 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 alternative 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 United States 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 in the event that the Regional Director determines that you fail to satisfy any lease obligation.

(g) You may pledge alternative types of security instruments instead of providing a bond if the Regional Director determines that the alternative security protects the interests of the United States to the same extent as the required bond.

(1) If you pledge an alternative 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 alternative 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 550, subpart N of this chapter;

(2) Suspend production and other operations on your leases in accordance with 30 CFR 250.173; and

(3) Initiate action to cancel your lease.

§ 556.901 Additional bonds.

(a) This paragraph explains what bonds you 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; or

(B) The date you submit a request for approval of the assignment of a lease on 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 approval of 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 sulfur leases held by the lessee on the OCS for the area in which the lease 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; or

(B) The date you submit a request for approval of the assignment of a lease on 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) You need not submit and maintain a $500,000 lease development bond pursuant to paragraph (b)(1) of this section if you furnish and maintain 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 sulfur leases you hold on the OCS for the area in which the lease is located.

(c) If you can demonstrate to the satisfaction of the authorized officer that you can satisfy your decommissioning obligations 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 decommissioning.

(d) The Regional Director may determine that additional security (*i.e.*, security above the amounts prescribed in § 556.900(a) and paragraphs (a) and (b) of this section) is necessary to ensure compliance with the obligations under your lease, the regulations in this chapter, and the regulations in 30 CFR chapters II and XII.

(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 for future production;

(iii) Business stability based on five years of continuous operation and production of oil and gas or sulfur in the OCS or in the onshore oil and gas industry;

(iv) Reliability in meeting obligations based on:

(A) Credit rating; 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 additional bond or bonds.

(e) The Regional Director will determine the amount of additional bond required to guarantee compliance. The

Regional Director will consider potential underpayment of royalty and cumulative decommissioning obligations.

(f) If your cumulative potential obligations and liabilities either increase or decrease, the Regional Director may adjust the amount of additional 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 additional 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 decommissioning are less than the required bond amount. If the Regional Director finds that the evidence you submit is convincing, the Regional Director may reduce the amount of additional bond required.

§ 556.902 General requirements for bonds.

(a) Any bond or other security that you, as lessee, operating rights owner 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, regulations in this chapter, and regulations under 30 CFR chapters II and XII; 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 Director. 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 non-cancellable, except as provided in § 556.906 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 § 556.900(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, and if the document omits terms or conditions contained on the form approved by the Director, the bond you submit will be deemed to contain the omitted terms and conditions.

§ 556.903 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 §§ 556.900 and 556.901 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 your 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 BOEM.

§ 556.904 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 § 556.901(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 BOEM and pledged to meet your decommissioning obligations.

(2) You must fully fund the lease-specific abandonment account to cover all decommissioning costs as estimated by BOEM 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 BOEM 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 BOEM 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 decommissioning of a lease. The required obligation may be associated with oil and gas or sulfur production from a lease other than the lease bonded through the lease-specific abandonment account.

§ 556.905 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 § 556.901(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, and decommissioning.

(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 30 CFR chapters II and XII, 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, the regulations in this chapter and 30 CFR chapters II and XII, 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, and	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 § 556.907, 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.

§ 556.906 Termination of the period of liability and cancellation of a bond.

This section defines the terms and conditions under which BOEM will terminate the period of liability of a bond or cancel a bond. Terminating the period of liability of a bond ends the period during which obligations continue to accrue, but does not relieve the surety of the responsibility for obligations that accrued during the period of liability. Canceling a bond relieves the surety of all liability. The liabilities that accrue during a period of liability include obligations that started to accrue prior to the beginning of the period of liability and had not been met, and obligations that begin accruing during the period of liability.

(a) When you or the surety under your bond requests termination:

(1) The Regional Director will terminate the period of liability under your bond within 90 days after BOEM receives the request; and

(2) If you intend to continue operations, or have not met all decommissioning obligations, you must provide a replacement bond of an equivalent amount.

(b) If you provide a replacement bond, the Regional Director will cancel your previous bond and the surety that provided your previous bond will not retain any liability, provided that:

(1) The new bond is equal to or greater than the bond that was terminated, or you provide an alternative form of security, and the Regional Director determines that the alternative form of security provides a level of security equal to or greater than that provided for by the bond that was terminated;

(2) For a base bond submitted under § 556.900(a) or under § 556.901(a) or (b), the surety issuing the new bond agrees to assume all outstanding liabilities that accrued during the period of liability that was terminated; and

(3) For additional bonds submitted under § 556.901(d), the surety issuing the new additional bond agrees to assume that portion of the outstanding liabilities that accrued during the period of liability that was terminated and that the Regional Director determines may exceed the coverage of the base bond, and of which the Regional Director notifies the provider of the bond.

(c) This paragraph applies if the period of liability is terminated for a bond, but the bond is not replaced by a bond of an equivalent amount. The surety that provided your terminated bond will continue to be responsible for accrued obligations:

(1) Until the obligations are satisfied; and

(2) For additional periods of time in accordance with paragraph (d) of this section.

(d) When your lease expires or is terminated, the surety that issued a bond will continue to be responsible, and the Regional Director will retain other forms of security as shown in the following table:

For the following type of bond	The period of liability will end	Your bond will be cancelled
(1) Base bonds submitted under § 556.900(a), § 556.901(a), or (b).	When the Regional Director determines that you have met all of your obligations under the lease,	Seven years after the termination of the lease, 6 years after completion of all bonded obligations, or at the conclusion of any appeals or litigation related to your bonded obligation, whichever is the latest. The Regional Director will reduce the amount of your bond or return a portion of your security if the Regional Director determines that you need less than the full amount of the base bond to meet any possible future problems.
(2) Additional bonds submitted under § 556.901(d).	When the Regional Director determines that you have met all your obligations covered by the additional bond,	When you meet your bonded obligations, unless the Regional Director: (i) Determines that the future potential liability resulting from any undetected problem is greater than the amount of the base bond; and (ii) Notifies the provider of the bond that the Regional Director will wait 7 years before cancelling all or a part of the bond (or longer period as necessary to complete any appeals or judicial litigation related to your bonding obligation).

(e) For all bonds, the Regional Director may reinstate your bond 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 BOEM that it has discharged its obligations under the lease, and the representation was materially false when the bond was canceled or released.

§ 556.907 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 on 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 a 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 reason 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 five 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 and 30 CFR chapters II and XII.

(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 and 30 CFR chapters II and XII. In this case, the Regional Director will return the excess funds to the party from whom they were collected.

Subpart J—Bonus or Royalty Credits for Exchange of Certain Leases

§ 556.1000 Leases formerly eligible for a bonus or royalty credit.

Bonus or royalty credits were available to lessees with leases:

(a) In effect on December 20, 2006, and located in:

(1) The Eastern Planning Area and within 125 miles of the coastline of the State of Florida; or,

(2) The Central Planning Area and within the Desoto Canyon OPD, the Destin Dome OPD, or the Pensacola OPD and within 100 miles of the coastline of the State of Florida.

(b) The deadline for applying for such a bonus or royalty credit was October 14, 2010; therefore, lessees may no longer apply for such credits.

Subpart K—Ending a Lease

§ 556.1100 How does a lease expire?

(a) Your oil and gas lease will automatically expire at the end of its primary term unless you have taken action, as set forth in § 556.601, to maintain the lease beyond the primary term.

(b) Your sulfur lease will automatically expire at the end of its primary term unless you have taken action, as set forth in § 556.603, to maintain the lease beyond the primary term.

§ 556.1101 May I relinquish my lease or an aliquot part thereof?

(a) A record title owner may relinquish a lease or an aliquot part of a lease if all record title owners of a lease or any aliquot part(s) of the lease file three original copies of a request to relinquish with BOEM on Form BOEM–0152, entitled, ''Relinquishment of Federal Oil and Gas Lease.'' No filing fee is required.

(b) A relinquishment will be subject to the continued obligation of the record title owner 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.

(c) The effective date of the relinquishment is the date on which the relinquishment is filed with the proper BOEM regional office.

§ 556.1102 Under what circumstances will BOEM cancel my lease?

(a) BOEM may cancel your non-producing lease if you fail to comply with any provision of OCSLA, the lease, or applicable regulations if the failure continues for 30 days after mailing of notice to your post office address of record by registered mail and you have not requested and been granted any additional time within which to correct the failure. Such cancellation is subject to judicial review under section 23 of OCSLA (43 U.S.C. 1349).

(b) Your producing lease may be cancelled if you fail to comply with any provision of OCSLA, the lease, or applicable regulations. The Secretary will cancel a producing lease after the judicial proceedings required under section 5(d) of OCSLA (43 U.S.C. 1334(d)).

(c) BOEM may cancel your lease if it determines that the lease was obtained by fraud or misrepresentation. You will have notice and an opportunity to be heard before BOEM cancels your lease.

(d) BOEM may cancel your lease at any time if it determines, after a hearing, that continued activity will probably cause serious harm or damage to life (including fish and other aquatic life), property, any mineral, national security or defense, or the marine, coastal, or human environment; that the threat of harm or damage will not disappear or decrease to an acceptable level within a reasonable period of time; and the advantages of cancellation outweigh the advantages of continuing the lease.

(e) BOEM may cancel your lease at any time after operations under the lease have been suspended or temporarily prohibited by the Department continuously for a period of five years pursuant to paragraph (d) of this section, absent your request for a shorter period.

(f) If, upon demand, you fail to provide a bond, or alternative type of security instrument acceptable to BOEM, the Regional Director may assess penalties or cancel your lease in accordance with part 550, subpart N of this chapter;

(g) Title 30, part 550, subpart A of the CFR provides the procedures for lease cancellation and compensation, if applicable.

Subpart L—Leases Maintained Under Section 6 of OCSLA

§ 556.1200 Effect of regulations on lease.

(a) All regulations in this part, insofar as they are applicable, will supersede the provisions of any lease that 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) will continue in effect, and, in the event of any conflict or inconsistency, will take precedence over these regulations.

(b) A lease maintained under section 6(a) of the Act is also 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 ROW(s) are applicable, to the extent that those regulations are not contrary to or inconsistent with the lease provisions relating to area, minerals, rentals, royalties and term. The lessee must comply with any provision of the lease as validated, the subject matter of which is not covered in the regulations in this part.

§ 556.1201 Section 6(a) leases and leases other than those for oil, gas, or sulfur.

The existence of an oil and gas lease maintained under section 6(a) of the Act precludes only the issuance in the same area of an oil and gas lease under OCSLA, but does not preclude the issuance of other types of leases under OCSLA. However, no other lease may authorize or permit the lessee thereunder unreasonably to interfere with or endanger operations under the existing lease. The United States will not grant any sulfur leases on any area that is included in a lease covering sulfur under section 6(b) of the Act.

Subpart M—Environmental Studies

§ 556.1300 Environmental studies.

(a) The Director will conduct a study or studies of any area or region included in any oil and gas lease sale or

other lease 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 or other mineral activities in such area or region. The purposes of such studies will include, to the extent practicable, analyses of the impacts of pollutants introduced into the environments and impacts of offshore activities on the seabed and affected coastal areas.

(b) Studies will be planned and carried out in cooperation with the affected States and interested parties and, to the extent possible, will not duplicate studies done under other laws. Where appropriate, the Director will, to the maximum extent practicable, coordinate with the National Oceanic and Atmospheric Administration (NOAA) in executing its environmental studies responsibilities. The Director may also make agreements for the coordination with, or the use of the services or resources of, any other Federal, State or local government agency in the conduct of such studies.

(c) Any study of an area or region required by paragraph (a) of this section for a lease sale will be commenced not later than six months prior to holding a lease sale for that area. The Director may use information collected in any prior study. The Director may initiate studies for an area or region not identified in the leasing program.

(d) After the leasing and developing of any area or region, the Director will conduct such studies as are deemed necessary to establish additional information and will 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 will be done to identify any significant changes in the quality and productivity of such environments, to establish trends in the area studies, and to design experiments identifying the causes of such changes. Findings from such studies will be used to recommend modifications in practices that 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 will, 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.

PART 560—OUTER CONTINENTAL SHELF OIL AND GAS LEASING

Subpart A—General Provisions

560.100 Authority
560.100 What is the purpose of this part?
560.102 What definitions apply to this part?
560.103 What is BOEM's authority to collect information?

Subpart B—Bidding Systems

GENERAL PROVISIONS

560.200 What is the purpose of this subpart?
560.201 What definitions apply to this subpart?
560.202 What bidding systems may BOEM use?
560.203 What conditions apply to the bidding systems that BOEM uses?

ELIGIBLE LEASES

560.210 How do royalty suspension volumes apply to eligible leases?
560.211 When does an eligible lease qualify for a royalty suspension volume?
560.212 How does BOEM assign and monitor royalty suspension volumes for eligible leases?
560.213 How long will a royalty suspension volume for an eligible lease be effective?
550.214 How do I measure natural gas production on my eligible lease?

ROYALTY SUSPENSIONS (RS) LEASES

560.220 How does royalty suspension apply to leases issued in a sale held after November 2000?
560.221 When does a lease issued in a sale held after November 2000 get a royalty suspension?
560.222 How long will a royalty suspension volume be effective for a lease issued in a sale held after November 2000?
560.223 How do I measure natural gas production for a lease issued in a sale held after November 2000?
560.224 How will royalty suspension apply if BOEM assigns a lease issued in a sale held after November 2000 to a field that has a pre-Act lease?

BIDDING SYSTEM SELECTION CRITERIA

560.230 What criteria does BOEM use for selecting bidding systems and bidding system components?

Subpart C—Operating Allowances

560.300 Operating allowances.

Subpart D [Reserved]

Subpart E—Electronic Filings

560.500 Electronic document and data transmissions.
560.501 How long will the confidentiality of electronic document and data transmissions be maintained?
560.502 Are electronically filed document transmissions legally binding?

AUTHORITY: Section 104, Public Law 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Public Law 109–432, Div C, Title I, 120 Stat. 3000; 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334; 33 U.S.C. 2704, 2716; E.O. 12777, as amended; 43 U.S.C. 1331 *et seq.*, 43 U.S.C. 1337.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General Provisions

§ 560.100 Authority.

(a) The Outer Continental Shelf Lands Act (OCSLA) (43 U.S.C. 1334) (''Outer Continental Shelf Lands Act Amendments of 1978'').

(b) The Federal Oil and Gas Royalty Management Act, as amended (FOGRMA) (30 U.S.C. 1711), including the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996, (30 U.S.C. 1701 note).

(c) The Independent Offices Appropriations Act of 1952 (31 U.S.C. 9701).

(d) Public Law 89–554, 1966 (5 U.S.C. 301).

[81 FR 18175, Mar. 30, 2016]

§ 560.101 What is the purpose of this part?

This part 560 implements the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1331 *et seq.*, as amended, by providing regulations to foster competition including, but not limited to:

(a) Implementing alternative bidding systems;

(b) Prohibiting joint bidding for development rights by certain types of joint ventures; and

(c) Establishing diligence requirements for Federal OCS leases.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.102 What definitions apply to this part? What definitions apply to this part?

(a) Terms used in this part have the meaning given in the Act and as defined in this part.

(b) The following definitions apply to this part:

Area or region means the geographic area or region over which the BOEM authorized officer has jurisdiction, unless the context in which those words are used indicates that a different meaning is intended.

BOEM means Bureau of Ocean Energy Management.

Designated official means a representative of DOI subject to the direction and supervisory authority of the Directors, BOEM, and the appropriate Regional Manager of the BOEM authorized and empowered to supervise and direct all oil and gas operations and to perform other duties prescribed in this chapter.

Director means Director, BOEM, 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 consideration, including, but not limited to, bonuses, rents or royalties conferred, and covenants 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 geothermal resources on lands or interests in lands under Federal jurisdiction.

Gas or Natural Gas means a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist in the gaseous phase.

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.

Outer Continental Shelf (OCS) means all submerged lands lying seaward and outside of the area of lands beneath

navigable waters as defined in the Submerged Lands Act (43 U.S.C. 1301–1315) and of which the subsoil and seabed appertain to the United States and 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. 1331–1356a, as amended by Pub. L. 95–372, 92 Stat. 629).

Person means a natural person, where so designated, or an entity, such as a partnership, association, State, political subdivision of a State or territory, or a private, public, or municipal corporation.

We means the Bureau of Ocean Energy Management (BOEM).

You means the lessee or operating rights owner.

[81 FR 18175, Mar. 30, 2016]

§ 560.103 What is BOEM's authority to collect information?

(a) The Paperwork Reduction Act of 1995 (PRA) requires us to inform you that we 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. The information collection under 30 CFR part 560 is either exempt from the PRA (5 CFR 1320.4(a)(2), (c)) or refers to requirements covered under 30 CFR parts 203 and 556.

(b) You may 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, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57097, Sept. 22, 2015. Redesignated at 81 FR 18175, Mar. 30, 2016]

Subpart B—Bidding Systems

GENERAL PROVISIONS

§ 560.200 What is the purpose of this subpart?

This subpart establishes the bidding systems that we may use to offer and sell Federal leases for the exploration, development, and production of oil and gas resources located on the OCS.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.201 What definitions apply to this subpart?

Act means the Outer Continental Shelf Deep Water Royalty Relief Act, Pub. L. 104–58, 43 U.S.C. 1337(3).

Eligible lease means a lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 1995, and before November 28, 2000;

(2) Is located in the Gulf of Mexico in water depths of 200 meters or deeper;

(3) Lies wholly west of 87 degrees, 30 minutes West longitude; and

(4) Is offered subject to a royalty suspension volume.

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. Two or more reservoirs may be in a field, 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 556, 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 percent rate payable to the United States, as specified in the lease, in the amount or value of the production saved, removed, or sold.

Lease period means the time from lease issuance until relinquishment, expiration, or termination.

Lowest royalty rate means the lowest percent rate payable to the United States, as specified in the lease, in the amount or value of the production saved, removed, or sold.

OCS lease sale means the Department of the Interior (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.

Pre-Act lease means a lease that:

(1) Is issued as part of an OCS lease sale held before November 28, 1995;

(2) Is located in the Gulf of Mexico in water depths of 200 meters or deeper; and

(3) Lies wholly west of 87 degrees, 30 minutes West longitude (see 30 CFR part 203).

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 556, subpart G.

Royalty rate means the percentage of the amount or value of the production saved, removed, or sold that is due and payable to the United States Government.

Royalty suspension (RS) lease means a lease that:

(1) Is issued as part of an OCS lease sale held after November 28, 2000;

(2) Is in locations or planning areas specified in a particular Notice of OCS Lease Sale; and

(3) Is offered subject to a royalty suspension specified in a Notice of OCS Lease Sale published in the FEDERAL REGISTER.

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 the 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 period of production. The value of production is determined under 30 CFR part 1206.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.202 What bidding systems may BOEM use?

We will apply a single bidding system selected from those listed in this section to each tract included in an OCS lease sale. The following table lists bidding systems, the bid variables, and characteristics.

For the bidding system . . .	The bid variable is the . . .	And the characteristics are . . .
(a) Cash bonus bid with a fixed royalty rate of not less than 12.5 percent,	Cash bonus,	The highest responsible qualified bidder will pay a royalty rate of not less than 12.5 percent at the beginning of the lease period. We will specify the royalty rate for each tract offered in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.
(b) Royalty rate bid with fixed cash bonus,	Royalty rate,	We will specify the fixed amount of cash bonus the highest responsible qualified bidder must pay in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.
(c) Cash bonus bid with a sliding royalty rate of not less than 12.5 percent at the beginning of the lease period,	Cash bonus,	(1) We will calculate the royalty rate the highest responsible qualified bidder must pay using either: (i) A sliding-scale formula, which relates the royalty rate to the adjusted value or volume of production, or (ii) A schedule that establishes the royalty rate that we will apply to specified ranges of the adjusted value or volume of production. (2) We will determine the adjusted value of production by applying an inflation factor to the actual value of production. (3) If you are the successful high bidder, your lease will include the sliding-scale formula or schedule and will specify the lowest and highest royalty rates that will apply. (4) You will pay a royalty rate of not less than 12.5 percent at the beginning of the lease period. (5) We will include the sliding-scale royalty formula or schedule, inflation factor and procedures for making the inflation adjustment and determining the value or amount of production in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.
(d) Cash bonus bid with fixed share of the net profits of no less than 30 percent,	Cash bonus,	(1) If we award you a lease as the highest responsible qualified bidder, you will determine the amount of the net profit share payment to the United States for each month by multiplying the net profit share base times the net profit share rate, according to 30 CFR 1220.022. You will calculate the net profit share base according to 30 CFR 1220.021. (2) You will pay a net profit share of not less than 30 percent.

For the bidding system . . .	The bid variable is the . . .	And the characteristics are . . .
		(3) We will specify the capital recovery factor, as described in 30 CFR 1220.020, and the net profit share rate, both of which may vary from tract to tract, in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.
(e) Cash bonus with variable royalty rate(s) during one or more periods of production,	Cash bonus,	(1) We may suspend or defer royalty for a period, volume, or value of production. Notwithstanding suspensions or deferrals, we may impose a minimum royalty. The suspensions or deferrals may vary based on prices or price changes of oil and/or gas. (2) You may pay a royalty rate less than 12.5 percent on production but not less than zero percent. (3) We will specify the applicable royalty rates(s) and suspension or deferral magnitudes, formulas, or relationships in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.
(f) Cash bonus with royalty rate(s) based on formula(s) or schedule(s) during one or more periods of production,	Cash bonus,	We will base the royalty rate on formula(s) or schedule(s) specified in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.
(g) Cash bonus with a fixed royalty rate of not less than 12.5 percent, at the beginning of the lease period, suspension of royalties for a period, volume, or value of production, or depending upon selected characteristics of extraction, and with suspensions that may vary based on the price of production,	Cash bonus,	Except for periods of royalty suspension, you will pay a fixed royalty rate of not less than 12.5 percent. If we award to you a lease under this system, you must calculate the royalty due during the designated period using the rate, formula, or schedule specified in the lease. We will specify the royalty rate, formula, or schedule in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.203 What conditions apply to the bidding systems that BOEM uses?

(a) For each of the bidding systems in § 560.110, we will include an annual rental fee. Other fees and provisions may apply as well. The Notice of OCS Lease Sale published in the FEDERAL REGISTER will specify the annual rental and any other fees the highest responsible qualified bidder must pay and any other provisions.

(b) If we use any deferment or schedule of payments for the cash bonus bid, we will specify and include it in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.

(c) For the bidding systems listed in this subpart, if the bid variable is a cash bonus bid, the highest bid by a qualified bidder determines the amount of cash bonus to be paid. We will include the minimum bid level(s) in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.

(d) For the bidding systems listed in this subpart, if the bid variable is the royalty rate, the highest bid by a qualified bidder determines the royalty rate to be paid. We will include the minimum royalty rate(s) in the Notice of OCS Lease Sale published in the FEDERAL REGISTER.

(e) We may, by rule, add to or modify the bidding systems listed in § 560.110, according to the procedural requirements of the OCSLA, 43 U.S.C. 1331 *et seq.*, as amended by Public Law 95–372, 92 Stat. 629.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

ELIGIBLE LEASES

§ 560.210 How do royalty suspension volumes apply to eligible leases?

Royalty suspension volumes, as specified in section 304 of the Act, apply to eligible leases that meet the criteria in § 560.113. For purposes of this section and §§ 560.113 through 560.117:

(a) Any volumes of production that are not normally royalty-bearing under the lease or the regulations (e.g., fuel gas) do not count against royalty suspension volumes; and

(b) Production includes volumes allocated to a lease under an approved unit agreement.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.211 When does an eligible lease qualify for a royalty suspension volume?

(a) Your eligible lease will receive a royalty suspension volume as specified in the Act. The bidding system in § 560.110(g) applies.

(b) Your eligible lease may receive a royalty suspension volume only if your entire lease is west of 87 degrees, 30 minutes West longitude.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.212 How does BOEM assign and monitor royalty suspension volumes for eligible leases?

(a) We have specified the water depth category for each eligible lease in the final Notice of OCS Lease Sale Package. The Final Notice of Sale is published in the FEDERAL REGISTER and the complete Final Notice of OCS Lease Sale Package is available on the BOEM Web site. Our determination of water depth for each lease became final when we issued the lease.

(b) We have specified in the Notice of OCS Lease Sale the royalty suspension volume applicable to each water depth. The following table shows the royalty suspension volumes for each eligible lease in million barrels of oil equivalent (MMBOE):

Water depth	Minimum royalty suspension volume
(1) 200 to less than 400 meters	17.5 MMBOE.
(2) 400 to less than 800 meters	52.5 MMBOE.
(3) 800 meters or more	87.5 MMBOE.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.213 How long will a royalty suspension volume for an eligible lease be effective?

A royalty suspension volume for an eligible lease will continue through the end of the month in which cumulative production from the leases in a field entitled to share the royalty suspension volume reaches that volume or the lease period ends.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.214 How do I measure natural gas production on my eligible lease?

You must measure natural gas production on your eligible lease subject to the royalty suspension volume as follows: 5.62 thousand cubic feet of natural gas, measured according to 30 CFR part 250, subpart L, equals one barrel of oil equivalent.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

ROYALTY SUSPENSION (RS) LEASES

§ 560.220 How does royalty suspension apply to leases issued in a sale held after November 2000?

We may issue leases with suspension of royalties for a period, volume or value of production, as authorized in section 303 of the Act. For purposes of this section and §§ 560.121 through 560.124:

(a) Any volumes of production that are not normally royalty-bearing under the lease or the regulations (e.g., fuel gas) do not count against royalty suspension volumes; and

(b) Production includes volumes allocated to a lease under an approved unit agreement.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.221 When does a lease issued in a sale held after November 2000 get a royalty suspension?

(a) We will specify any royalty suspension for your RS lease in the Notice of OCS Lease Sale published in the FEDERAL REGISTER for the sale in which you acquire the RS lease and will repeat it in the lease document. In addition:

(1) Your RS lease may produce royalty-free the royalty suspension we specify for your lease, even if the field to which we assign it is producing.

(2) The royalty suspension we specify in the Notice of OCS Lease Sale for your lease does not apply to any other leases in the field to which we assign your RS lease.

(b) You may apply for a supplemental royalty suspension for a project under 30 CFR part 203, if your lease is located:

(1) In the Gulf of Mexico, in water 200 meters or deeper, and wholly west of 87 degrees, 30 minutes West longitude; or

(2) Offshore of Alaska.

(c) Your RS lease retains the royalty suspension with which we issued it even if we deny your application for more relief.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.222 How long will a royalty suspension volume be effective for a lease issued in a sale held after November 2000?

(a) The royalty suspension volume for your RS lease will continue through the end of the month in which cumulative production from your lease reaches the applicable royalty suspension volume or the lease period ends.

(b)(1) Notwithstanding any royalty suspension volume under this subpart, you must pay royalty at the lease stipulated rate on:

(i) Any oil produced for any period stipulated in the lease during which the arithmetic average of the daily closing price on the New York Mercantile Exchange (NYMEX) for light sweet crude oil exceeds the applicable threshold price of $36.39 per barrel, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.

(ii) Any natural gas produced for any period stipulated in the lease during which the arithmetic average of the daily closing price on the NYMEX for natural gas exceeds the applicable threshold price of $4.55 per MMBtu, adjusted annually after calendar year 2007 for inflation unless the lease terms prescribe a different price threshold.

(iii) Determine the threshold price for any calendar year after 2007 by adjusting the threshold price in the previous year by the percentage that the implicit price deflator for the gross domestic product, as published by the Department of Commerce, changed during the calendar year.

(2) You must pay any royalty due under this paragraph, plus late payment interest under 30 CFR 1218.54, no later than 90 days after the end of the period for which royalty is owed.

(3) Any production on which you must pay royalty under this paragraph will count toward the production volume determined under §§ 560.120 through 560.124.

(c) If you must pay royalty on any product (either oil or natural gas) for any period under paragraph (b) of this section, you must continue to pay royalty on that product during the next succeeding period of the same length until the arithmetic average of the daily closing NYMEX prices for that product for that period can be determined. If the arithmetic average of the daily closing prices for that product for that period is less than the threshold price stipulated in the lease, you are entitled to a credit or refund of royalties paid for that period with interest under applicable law.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.223 How do I measure natural gas production for a lease issued in a sale held after November 2000?

You must measure natural gas production subject to the royalty suspension volume for your lease as follows: 5.62 thousand cubic feet of natural gas, measured according to 30 CFR part 250, subpart L, equals one barrel of oil equivalent.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

§ 560.224 How will royalty suspension apply if BOEM assigns a lease issued in a sale held after November 2000 to a field that has a pre-Act lease?

(a) We will assign your lease that has a qualifying well (under 30 CFR part 250, subpart A) to an existing field or designate a new field and will notify you and other affected lessees and operating rights holders in the field of that assignment.

(1) Within 15 days of the final notification, you or any of the other affected lessees or operating rights holders may file a written request with the Director for reconsideration, accompanied by a Statement of Reasons.

(2) The Director will respond in writing either affirming or reversing the

assignment decision. The Director's decision is the final action of the Department of the Interior and is not subject to appeal to the Interior Board of Land Appeals under 30 CFR part 590 and 43 CFR part 4.

(b) If we establish a royalty suspension volume for a field as a result of an approved application for royalty relief submitted for a pre-Act lease under 30 CFR part 203, then:

(1) Royalty-free production from your RS lease shares from and counts as part of any royalty suspension volume under § 560.114(d) for the field to which we assign your lease; and

(2) Your RS lease may continue to produce royalty-free up to the royalty suspension we specified for your lease, even if the field to which we assign your RS lease has produced all of its royalty suspension volume.

(c) Your lease may share in a suspension volume larger than the royalty suspension with which we issued it and to the extent we grant a larger volume in response to an application by a pre-Act lease submitted under 30 CFR part 203. To share in any larger royalty suspension volume, you must file an application described in 30 CFR part 203 (§§ 203.71 and 203.83). In no case will royalty-free production for your RS lease be less than the royalty suspension specified for your lease.

[76 FR 64623, Oct. 18, 2011. Redesignated at 81 FR 18175, Mar. 30, 2016]

BIDDING SYSTEM SELECTION CRITERIA

§ 560.230 What criteria does BOEM use for selecting bidding systems and bidding system components?

In analyzing the application of one of the bidding systems listed in § 560.110 to tracts selected for any OCS lease sale, we may, at our discretion, consider the following purposes and policies. We recognize that each of the purposes and policies may not be specifically applicable to the selection process for a particular bidding system or tract, or may present a conflict that we will have to resolve in the process of bidding system selection. The order of listing does not denote a ranking.

(a) Providing fair return to the Federal Government;

(b) Increasing competition;

(c) Ensuring competent and safe operations;

(d) Avoiding undue speculation;

(e) Avoiding unnecessary delays in exploration, development, and production;

(f) Discovering and recovering oil and gas;

(g) Developing new oil and gas resources in an efficient and timely manner;

(h) Limiting the administrative burdens on Government and industry; and

(i) Providing an opportunity to experiment with various bidding systems to enable us to identify those most appropriate for the satisfaction of the objectives of the United States in OCS lease sales.

Subpart C—Operating Allowances

§ 560.300 Operating allowances.

Notwithstanding any other provision in the regulations in this part, BOEM may issue a lease containing an operating allowance when so specified in the final notice of sale and the lease. The allowance amount or formula will be specified in the final notice of sale and in the lease.

[81 FR 18175, Mar. 10, 2016]

Subpart D [Reserved]

Subpart E—Electronic Filings

SOURCE: 81 FR 18176, Mar. 30, 2016, unless otherwise noted.

§ 560.500 Electronic document and data transmissions.

(a) BOEM may notify you that it will allow or request you to submit the following information electronically through BOEM's secure electronic filing system, through an alternate secure electronic filing system supported and maintained by the Department, or through some other electronic filing system that BOEM has approved for this purpose:

(1) Any document(s) or information described in the Qualifications section of part 556 of this chapter, as specified in subpart E. Such information would include, but not be limited to, the official name of the qualifying person, its

legal and business address or addresses, its legal form and status, and the names and contact information of a person or organization authorized to act on the person's behalf.

(2) Any document(s) or information required to obtain BOEM's approval of an assignment or sublease, including any form or instrument that creates or transfers ownership of a lease interest.

(3) Any document(s) or information required to obtain BOEM's approval of your relinquishment of all, or any aliquot part of your lease, as specified in § 556.1101 of this chapter.

(4) Any document(s) creating, transferring or assigning economic interests, as specified in §§ 556.715 and 556.808 of this chapter.

(5) Any document(s) related to a bond, U.S. Treasury note or other security provided to BOEM, which is required to guarantee your compliance with terms and conditions of a lease.

(6) Any document(s) or information necessary to bid for an OCS lease.

(7) Any forms, document(s) or information necessary to determine worst case oil-spill discharge volume(s), or to provide evidence demonstrating oil spill financial responsibility, or to guarantee such financial responsibility or to comply with any other requirements of the Oil Spill Financial Responsibility Program, as described in part 553 of this chapter.

(b) BOEM reserves the right to require the electronic filing of any document(s) or information addressed in paragraph (a)(5) of this section upon a 90-day notice published in the FEDERAL REGISTER; if BOEM mandates that you transmit such document(s) or information electronically, the FEDERAL REGISTER notice will specify the filing details necessary to comply with this regulation.

(c) In the event BOEM sends documents to you in a secure electronic format, you may either return the document(s) in an electronic format utilizing the same secure transmission mechanism or print the document(s) and return them.

(d) BOEM may electronically acknowledge, approve, sign, or execute any document(s) referenced in this section.

§ 560.501 How long will the confidentiality of electronic document and data transmissions be maintained?

The confidentiality of any electronically submitted information will be maintained for the same proprietary term that would apply to the corresponding non-electronic confidential submission, pursuant to § 556.104(b) of this chapter.

§ 560.502 Are electronically filed document transmissions legally binding?

Any document or information referenced in § 560.500 which is submitted to BOEM through a secure electronic filing system that is approved by BOEM will be legally binding, without the need for a paper copy thereof.

PART 570—NONDISCRIMINATION IN THE OUTER CONTINENTAL SHELF

Sec.
570.1 Purpose.
570.2 Application of this part.
570.3 Definitions.
570.4 Discrimination prohibited.
570.5 Complaint.
570.6 Process.
570.7 Remedies.

AUTHORITY: 43 U.S.C. 1863.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

§ 570.1 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.''

§ 570.2 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.

§ 570.3 Definitions.

As used in this part, the following terms shall have the following meaning:

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.

§ 570.4 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.

§ 570.5 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.

§ 570.6 Process.

Whenever a Regional Director determines on the basis of any information, including that which may be obtained under § 570.5 of this part, 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 must proceed in accordance with the provisions of 30 CFR part 550, subpart N.

§ 570.7 Remedies.

In addition to the penalties available under 30 CFR part 550, subpart N, 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 580—PROSPECTING FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR ON THE OUTER CONTINENTAL SHELF

Subpart A—General Information

Sec.
580.1 What definitions apply to this part?
580.2 What is the purpose of this part?
580.3 What requirements must I follow when I conduct prospecting or research activities?
580.4 What activities are not covered by this part?

Subpart B—How To Apply for a Permit or File a Notice

580.10 What must I do before I may conduct prospecting activities?
580.11 What must I do before I may conduct scientific research?
580.12 What must I include in my application or notification?
580.13 Where must I send my application or notification?

Subpart C—Obligations Under This Part

PROHIBITIONS AND REQUIREMENTS

580.20 What must I not do in conducting Geological and Geophysical (G&G) prospecting or scientific research?
580.21 What must I do in conducting G&G prospecting or scientific research?
580.22 What must I do when seeking approval for modifications?
580.23 How must I cooperate with inspection activities?
580.24 What reports must I file?

INTERRUPTED ACTIVITIES

580.25 When may BOEM require me to stop activities under this part?
580.26 When may I resume activities?
580.27 When may BOEM cancel my permit?
580.28 May I relinquish my permit?

ENVIRONMENTAL ISSUES

580.29 Will BOEM monitor the environmental effects of my activity?
580.30 What activities will not require environmental analysis?
580.31 Whom will BOEM notify about environmental issues?

PENALTIES AND APPEALS

580.32 What penalties may I be subject to?
580.33 How can I appeal a penalty?
580.34 How can I appeal an order or decision?

Subpart D—Data Requirements

GEOLOGICAL DATA AND INFORMATION

580.40 When do I notify BOEM that geological data and information are available for submission, inspection, and selection?
580.41 What types of geological data and information must I submit to BOEM?
580.42 When geological data and information are obtained by a third party, what must we both do?

YSICAL DATA AND INFORMATION

580.50 When do I notify BOEM that geophysical data and information are available for submission, inspection, and selection?
580.51 What types of geophysical data and information must I submit to BOEM?
580.52 When geophysical data and information are obtained by a third party, what must we both do?

REIMBURSEMENT

580.60 Which of my costs will be reimbursed?
580.61 Which of my costs will not be reimbursed?

PROTECTIONS

580.70 What data and information will be protected from public disclosure?
580.71 What is the timetable for release of data and information?
580.72 What procedure will BOEM follow to disclose acquired data and information to a contractor for reproduction, processing, and interpretation?
580.73 Will BOEM share data and information with coastal States?

Subpart E—Information Collection

580.80 Paperwork Reduction Act statement—information collection.

AUTHORITY: Section 104, Public Law 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Public Law 109–432, Div C, Title I, 120 Stat. 3000; 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334; 33 U.S.C. 2704, 2716; E.O. 12777, as amended; 43 U.S.C. 1331 *et seq.*, 43 U.S.C. 1337.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General Information

§ 580.1 What definitions apply to this part?

Definitions in this part have the following meaning:

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 geological and geophysical (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.

Analyzed geological information means data collected under a permit or a lease that have been analyzed. Some examples of analysis include, but are not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of mineral occurrences or hazardous conditions.

Archaeological interest means capable of providing scientific or humanistic understandings 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.

Archaeological resource means any material remains of human life or activities that are at least 50 years of age and are of archaeological interest.

Coastal environment means the physical, atmospheric, and biological components, conditions, and factors that 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) that are 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 United States 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, under the authority in section 305(b)(1) of the Coastal Zone Management Act of 1972.

Coastal Zone Management Act means the Coastal Zone Management Act of 1972, as amended (16 U.S.C. 1451 *et seq.*).

Data means facts and statistics, measurements, or samples that have not been analyzed, processed, or interpreted.

Deep stratigraphic test means drilling that involves the penetration into the sea bottom of more than 500 feet (152 meters).

Director means the Director of the Bureau of Ocean Energy Management, U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

Geological and geophysical (G&G) prospecting activities mean the commercial search for mineral resources other than oil, gas, or sulphur. Activities classified as prospecting include, but are not limited to:

(1) Geological and geophysical marine and airborne surveys where magnetic, gravity, seismic reflection, seismic refraction, or the gathering through coring or other geological samples are used to detect or imply the presence of hard minerals; and

(2) Any drilling, whether on or off a geological structure.

Geological and geophysical (G&G) scientific research activities mean any investigations related to hard minerals that are conducted on the OCS for academic or scientific research. These investigations would involve gathering and analyzing geological, geochemical, or geophysical data and information that are made available to the public for inspection and reproduction at the earliest practical time. The term does not include commercial G&G exploration or commercial G&G prospecting activities.

Geological data and information means data and information gathered through or derived from geological and geochemical techniques, e.g., coring and test drilling, well logging, bottom sampling, or other physical sampling or chemical testing process.

Geological sample means a collected portion of the seabed, the subseabed, or the overlying waters acquired while conducting prospecting or scientific research activities.

Geophysical data and information means any data or information gathered through or derived from geophysical measurement or sensing techniques (e.g., gravity, magnetic, or seismic).

Governor means the Governor of a State or the person or entity lawfully designated by or under State law to exercise the powers granted to a Governor under the Act.

Hard minerals mean any minerals found on or below the surface of the seabed except for oil, gas, or sulphur.

Interpreted geological information means the knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geological data and analyzed and processed geologic information.

Interpreted geophysical information means knowledge, often in the form of seismic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

Lease means, depending upon the requirements of the context, either:

(1) An agreement issued under section 8 or maintained under section 6 of the Act that authorizes mineral exploration, development and production; or

(2) The area covered by an agreement specified in paragraph (1) of this definition.

Material remains means physical evidence of human habitation, occupation, use, or activity, including the site, location, or context in which evidence is situated.

Minerals mean all minerals 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). The term includes oil, gas, sulphur, geopressured-geothermal and associated resources.

Notice means a written statement of intent to conduct G&G scientific research that is:

(1) Related to hard minerals on the OCS; and

(2) Not covered under a permit.

Oil, gas, and sulphur means oil, gas, and sulphur, geopressured-geothermal and associated resources, including gas hydrates.

Outer Continental Shelf (OCS) means all submerged lands:

(1) That lie 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

(2) Whose subsoil and seabed belong to the United States and are subject to its jurisdiction and control.

Permit means the contract or agreement, other than a lease, issued under this part. The permit gives a person the right, under appropriate statutes, regulations, and stipulations, to conduct on the OCS:

(1) Geological prospecting for hard minerals;

(2) Geophysical prospecting for hard minerals;

(3) Geological scientific research; or

(4) Geophysical scientific research.

Permittee means the person authorized by a permit issued under this part to conduct activities on the OCS.

Person means:

(1) A citizen or national of the United States;

(2) An alien lawfully admitted for permanent residence in the United States as defined in section 8 U.S.C. 1101(a)(20);

(3) A private, public, or municipal corporation organized under the laws of the United States or of any State or territory thereof, and association of such citizens, nationals, resident aliens or private, public, or municipal corporations, States, or political subdivisions of States; or

(4) Anyone operating in a manner provided for by treaty or other applicable international agreements. The term does not include Federal agencies.

Processed geological or geophysical information means data collected under a permit and later processed or reprocessed.

(1) Processing involves changing the form of data as to facilitate interpretation. Some examples of processing operations may include, but are not limited to:

(i) Applying corrections for known perturbing causes;

(ii) Rearranging or filtering data; and

(iii) Combining or transforming data elements.

(2) Reprocessing is the additional processing other than ordinary processing used in the general course of evaluation. Reprocessing operations may include varying identified parameters for the detailed study of a specific problem area.

Secretary means the Secretary of the Interior or a subordinate authorized to act on the Secretary's behalf.

Shallow test drilling means drilling into the sea bottom to depths less than those specified in the definition of a deep stratigraphic test.

Significant archaeological resource means those archaeological resources that meet the criteria of significance for eligibility of the National Register of Historic Places as defined in 36 CFR 60.4, or its successor.

Third party means any person other than the permittee or a representative of the United States, including all persons who obtain data or information acquired under a permit from the permittee, or from another third party, by sale, trade, license agreement, or other means.

You means a person who applies for and/or obtains a permit, or files a notice to conduct G&G prospecting or scientific research related to hard minerals on the OCS.

§ 580.2 What is the purpose of this part?

The purpose of this part is to:

(a) Allow you to conduct prospecting activities or scientific research activities on the OCS in Federal waters related to hard minerals on unleased lands or on lands under lease to a third party.

(b) Ensure that you carry out prospecting activities or scientific research activities in a safe and environmentally sound manner so as to prevent harm or damage to, or waste of, any natural resources (including any hard minerals in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

(c) Inform you and third parties of your legal and contractual obligations.

(d) Inform you and third parties of:

(1) The U.S. Government's rights to access G&G data and information collected under permit on the OCS;

(2) Reimbursement we will make for data and information that are submitted; and

(3) The proprietary terms of data and information that we retain.

§ 580.3 What requirements must I follow when I conduct prospecting or research activities?

You must conduct G&G prospecting activities or scientific research activities under this part according to:

(a) The Act;

(b) The regulations in this part;

(c) Orders of the Director/Regional Director (RD); and

(d) Other applicable statutes, regulations, and amendments.

§ 580.4 What activities are not covered by this part?

This part does not apply to:

(a) G&G prospecting activities conducted by, or on behalf of, the lessee on a lease on the OCS;

(b) Federal agencies;

(c) Postlease activities for mineral resources other than oil, gas, and sulphur, which are covered by regulations at 30 CFR parts 582 and 282; and

(d) G&G exploration or G&G scientific research activities related to oil, gas, and sulphur, including gas hydrates, which are covered by regulations at 30 CFR parts 551 and 251.

Subpart B—How To Apply for a Permit or File a Notice

§ 580.10 What must I do before I may conduct prospecting activities?

You must have a BOEM-approved permit to conduct G&G prospecting activities, including deep stratigraphic tests, for hard minerals. If you conduct both G&G prospecting activities, you must have a separate permit for each.

§ 580.11 What must I do before I may conduct scientific research?

You may conduct G&G scientific research activities related to hard minerals on the OCS only after you obtain a BOEM-approved permit or file a notice.

(a) *Permit*. You must obtain a permit if the research activities you want to conduct involve:

(1) Using solid or liquid explosives;

(2) Drilling a deep stratigraphic test; or

(3) Developing data and information for proprietary use or sale.

(b) *Notice*. If you conduct research activities (including federally funded research) not covered by paragraph (a) of this section, you must file a notice with the regional director at least 30 days before you begin. If you cannot file a 30-day notice, you must provide oral notification before you begin and follow up in writing. You must also inform BOEM in writing when you conclude your work.

§ 580.12 What must I include in my application or notification?

(a) *Permits*. You must submit to the Regional Director a signed original and three copies of the permit application form (Form BOEM–0134) at least 30 days before the startup date for activities in the permit area. If unusual circumstances prevent you from meeting this deadline, you must immediately contact the Regional Director to arrange an acceptable deadline. The form includes names of persons; the type, location, purpose, and dates of activity; and environmental and other information. A nonrefundable service fee of $2,012 must be paid electronically through *Pay.gov* at: *https://www.pay.gov/paygov/* and you must include a copy of the *Pay.gov* confirmation receipt page with your application.

(b) *Disapproval of permit application*. If we disapprove your application for a permit, the RD will explain the reasons for the disapproval and what you must do to obtain approval.

(c) *Notices*. You must sign and date a notice that includes:

(1) The name(s) of the person(s) who will conduct the proposed research;

(2) The name(s) of any other person(s) participating in the proposed research, including the sponsor;

(3) The type of research and a brief description of how you will conduct it;

(4) A map, plat, or chart, that shows the location where you will conduct research;

(5) The proposed projected starting and ending dates for your research activity;

(6) The name, registry number, registered owner, and port of registry of vessels used in the operation;

(7) The earliest practical time you expect to make the data and information resulting from your research activity available to the public;

(8) Your plan of how you will make the data and information you collect available to the public;

(9) A statement that you and others involved will not sell or withhold the data and information resulting from your research; and

(10) At your option, the nonexclusive use agreement for scientific research attachment to Form BOEM–0134. (If you submit this agreement, you do not have to submit the material required in paragraphs (c)(7), (c)(8), and (c)(9) of this section.)

§ 580.13 Where must I send my application or notification?

You must apply for a permit or file a notice at one of the following locations:

For the OCS off the . . .	Apply to . . .
(a) State of Alaska	Regional Supervisor for Resource Evaluation, Bureau of Ocean Energy Management, Alaska OCS Region, 3801 Centerpoint Drive, Suite 500, Anchorage, AK 99503.
(b) Atlantic Coast, Gulf of Mexico, Puerto Rico, or U.S. territories in the Caribbean Sea.	Regional Supervisor for Resource Evaluation, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, 1201 Elmwood Park Boulevard, New Orleans, LA 70123–2394.
(c) States of California, Oregon, Washington, Hawaii, or U.S. territories in the Pacific Ocean.	Regional Supervisor for Resource Evaluation, Bureau of Ocean Energy Management, Pacific OCS Region, 760 Paseo Camarillo, Suite 102 (CM 102), Camarillo, CA 93010.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57097, Sept. 22, 2015]

Subpart C—Obligations Under This Part

PROHIBITIONS AND REQUIREMENTS

§ 580.20 What must I not do in conducting Geological and Geophysical (G&G) prospecting or scientific research?

While conducting G&G prospecting or scientific research activities under a permit or notice, you must not:

(a) Interfere with or endanger operations under any lease, right-of-way, easement, right-of-use, notice, or permit issued or maintained under the Act;

(b) Cause harm or damage to life (including fish and other aquatic life), property, or the marine, coastal, or human environment;

(c) Cause harm or damage to any mineral resources (in areas leased or not leased);

(d) Cause pollution;

(e) Disturb archaeological resources;

(f) Create hazardous or unsafe conditions;

(g) Unreasonably interfere with or cause harm to other uses of the area; or

(h) Claim any oil, gas, sulphur, or other minerals you discover while conducting operations under a permit or notice.

§ 580.21 What must I do in conducting G&G prospecting or scientific research?

While conducting G&G prospecting or scientific research activities under a permit or notice, you must:

(a) Immediately report to the Regional Director if you:

(1) Detect hydrocarbon or any other mineral occurrences;

(2) Detect environmental hazards that imminently threaten life and property; or

(3) Adversely affect the environment, aquatic life, archaeological resources, or other uses of the area where you are prospecting or conducting scientific research activities.

(b) Consult and coordinate your G&G activities with other users of the area for navigation and safety purposes.

(c) If you conduct shallow test drilling or deep stratigraphic test drilling activities, you must use the best available and safest technologies that the Regional Director considers economically feasible.

§ 580.22 What must I do when seeking approval for modifications?

Before you begin modified operations, you must submit a written request describing the modifications and receive the Regional Director's oral or written approval. If circumstances preclude a written request, you must make an oral request and follow up in writing.

§ 580.23 How must I cooperate with inspection activities?

(a) You must allow our representatives to inspect your G&G prospecting or any scientific research activities that are being conducted under a permit. They will determine whether operations are adversely affecting the environment, aquatic life, archaeological resources, or other uses of the area.

(b) BOEM will reimburse you for food, quarters, and transportation that you provide for our representatives if you send in your reimbursement request to the region that issued the permit within 90 days of the inspection.

§ 580.24 What reports must I file?

(a) You must submit status reports on a schedule specified in the permit and include a daily log of operations.

(b) You must submit a final report of G&G prospecting or scientific research activities under a permit within 30 days after you complete acquisition activities under the permit. You may combine the final report with the last status report and must include each of the following:

(1) A description of the work performed.

(2) Charts, maps, plats and digital navigation data in a format specified by the Regional Director, showing the areas and blocks in which any G&G prospecting or permitted scientific research activities were conducted. Identify the lines of geophysical traverses and their locations including a reference sufficient to identify the data produced during each activity.

(3) The dates on which you conducted the actual prospecting or scientific research activities.

(4) A summary of any:

(i) Hard mineral, hydrocarbon, or sulphur occurrences encountered;

(ii) Environmental hazards; and

(iii) Adverse effects of the G&G prospecting or scientific research activities on the environment, aquatic life, archaeological resources, or other uses of the area in which the activities were conducted.

(5) Other descriptions of the activities conducted as specified by the Regional Director.

INTERRUPTED ACTIVITIES

§ 580.25 When may BOEM require me to stop activities under this part?

(a) We may temporarily stop prospecting or scientific research activities under a permit when the Regional Director determines that:

(1) Activities pose a threat of serious, irreparable, or immediate harm. This includes damage to life (including fish and other aquatic life), property, and any minerals (in areas leased or not leased), to the marine, coastal, or human environment, or to an archaeological resource;

(2) You failed to comply with any applicable law, regulation, order or provision of the permit. This would include our required submission of reports, well records or logs, and G&G data and information within the time specified; or

(3) Stopping the activities is in the interest of National security or defense.

(b) The Regional Director will advise you either orally or in writing of the procedures to temporarily stop activities. We will confirm an oral notification in writing and deliver all written notifications by courier or certified/registered mail. You must stop all activities under a permit as soon as you receive an oral or written notification.

§ 580.26 When may I resume activities?

The Regional Director will advise you when you may start your permit activities again.

§ 580.27 When may BOEM cancel my permit?

The Regional Director may cancel a permit at any time.

(a) If we cancel your permit, the Regional Director will advise you by certified or registered mail 30 days before the cancellation date and will state the reason.

(b) After we cancel your permit, you are still responsible for proper abandonment of any drill site according to the requirements of 30 CFR 251.7(b)(8). You must comply with all other obligations specified in this part or in the permit.

§ 580.28 May I relinquish my permit?

(a) You may relinquish your permit at any time by advising the Regional Director by certified or registered mail 30 days in advance.

(b) After you relinquish your permit, you are still responsible for proper abandonment of any drill sites according to the requirements of 30 CFR 251.7(b)(8). You must also comply with all other obligations specified in this part or in the permit.

ENVIRONMENTAL ISSUES

§ 580.29 Will BOEM monitor the environmental effects of my activity?

We will evaluate the potential of proposed prospecting or scientific research activities for adverse impact on the environment to determine the need for mitigation measures.

§ 580.30 What activities will not require environmental analysis?

We anticipate that activities of the type listed below typically will not cause significant environmental impact and 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) Hard minerals sampling of a limited nature such as shallow test drilling;

(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 hard mineral assaying and analysis; and

(j) Placement of positioning systems, including bottom transponders and surface and subsurface buoys reported in Notices to Mariners.

§ 580.31 Whom will BOEM notify about environmental issues?

(a) In cases where Coastal Zone Management Act consistency review is required, the Director will notify the Governor of each adjacent State with a copy of the application for a permit immediately upon the submission for approval.

(b) In cases where an environmental assessment is to be prepared, the Director will invite the Governor of each adjacent State to review and provide comments regarding the proposed activities. The Director's invitation to provide comments will allow the Governor a specified period of time to comment.

(c) When a permit is issued, the Director will notify affected parties including each affected coastal State, Federal agency, local government, and special interest organization that has expressed an interest.

PENALTIES AND APPEALS

§ 580.32 What penalties may I be subject to?

(a) *Penalties for noncompliance under a permit.* You are subject to the penalty provisions of section 24 of the Act (43 U.S.C. 1350) and the procedures contained in 30 CFR part 550, subpart N for noncompliance with:

(1) Any provision of the Act;

(2) Any provisions of a G&G or drilling permit; or

(3) Any regulation or order issued under the Act.

(b) *Penalties under other laws and regulations.* The penalties prescribed in this section are in addition to any other penalty imposed by any other law or regulation.

§ 580.33 How can I appeal a penalty?

See 30 CFR part 550.1409 and 30 CFR part 590, subpart A, for instructions on how to appeal any decision assessing a civil penalty under 43 U.S.C. 1350 and 30 CFR part 550, subpart A.

§ 580.34 How can I appeal an order or decision?

See 30 CFR part 590, subpart A, for instructions on how to appeal an order or decision.

Subpart D—Data Requirements

GEOLOGICAL DATA AND INFORMATION

§ 580.40 When do I notify BOEM that geological data and information are available for submission, inspection, and selection?

(a) You must notify the Regional Director, in writing, when you complete the initial analysis, processing, or interpretation of any geological data and information. Initial analysis and processing are the stages of analysis or processing where the data and information first become available for in-house interpretation by the permittee or become available commercially to third parties via sale, trade, license agreement, or other means.

(b) The Regional Director may ask if you have further analyzed, processed, or interpreted any geological data and information. When asked, you must respond to us in writing within 30 days.

(c) The Regional Director may ask you or a third party to submit the analyzed, processed, or interpreted geologic data and information for us to inspect or permanently retain. You must submit the data and information within 30 days after such a request.

§ 580.41 What types of geological data and information must I submit to BOEM?

Unless the Regional Director specifies otherwise, you must submit geological data and information that include:

(a) An accurate and complete record of all geological (including geochemical) data and information describing each operation of analysis, processing, and interpretation;

(b) Paleontological reports identifying by depth any microscopic fossils collected, including the reference datum to which paleontological sample depths are related and, if the Regional Director requests, washed samples, that you maintain for paleontological determinations;

(c) Copies of well logs or charts in a digital format, if available;

(d) Results and data obtained from formation fluid tests;

(e) Analyses of core or bottom samples and/or a representative cut or split of the core or bottom sample;

(f) Detailed descriptions of any hydrocarbons or other minerals or hazardous conditions encountered during operations, including near losses of well control, abnormal geopressures, and losses of circulation; and

(g) Other geological data and information that the RD may specify.

§ 580.42 When geological data and information are obtained by a third party, what must we both do?

A third party may obtain geological data and information from a permittee, or from another third party, by sale, trade, license agreement, or other means. If this happens:

(a) The third-party recipient of the data and information assumes the obligations under this part, except for the notification provisions of § 580.40(a) and is subject to the penalty provisions of § 580.32(a)(1) and 30 CFR part 550, subpart N; and

(b) A permittee or third party that sells, trades, licenses, or otherwise provides data and information to a third party must advise the recipient, in writing, that accepting these obligations is a condition precedent of the sale, trade, license, or other agreement; and

(c) Except for license agreements, a permittee or third party that sells, trades, or otherwise provides data and information to a third party must advise the Regional Director in writing within 30 days of the sale, trade, or other agreement, including the identity of the recipient of the data and information; or

(d) For license agreements, a permittee or third party that licenses data and information to a third party must, within 30 days of a request by the Regional Director, advise the Regional Director, in writing, of the license agreement, including the identity of the recipient of the data and information.

GEOPHYSICAL DATA AND INFORMATION

§ 580.50 When do I notify BOEM that geophysical data and information are available for submission, inspection, and selection?

(a) You must notify the Regional Director in writing when you complete the initial processing and interpretation of any geophysical data and information. Initial processing is the stage of processing where the data and information become available for in-house interpretation by the permittee, or become available commercially to third parties via sale, trade, license agreement, or other means.

(b) The Regional Director may ask whether you have further processed or interpreted any geophysical data and information. When asked, you must respond to us in writing within 30 days.

(c) The Regional Director may request that the permittee or third party submit geophysical data and information before making a final selection for retention. Our representatives may inspect and select the data and information on your premises, or the Regional Director can request delivery of the data and information to the appropriate regional office for review.

(d) You must submit the geophysical data and information within 30 days of receiving the request, unless the Regional Director extends the delivery time.

(e) At any time before final selection, the Regional Director may review and return any or all geophysical data and information. We will notify you in

writing of any data the RD decides to retain.

§ 580.51 What types of geophysical data and information must I submit to BOEM?

Unless the Regional Director specifies otherwise, you must include:

(a) An accurate and complete record of each geophysical survey conducted under the permit, including digital navigational data and final location maps;

(b) All seismic data collected under a permit presented in a format and of a quality suitable for processing;

(c) Processed geophysical information derived from seismic data with extraneous signals and interference removed, presented in a quality format suitable for interpretive evaluation, reflecting state-of-the-art processing techniques; and

(d) Other geophysical data, processed geophysical information, and interpreted geophysical information including, 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.

§ 580.52 When geophysical data and information are obtained by a third party, what must we both do?

A third party may obtain geophysical data, processed geophysical information, or interpreted geophysical information from a permittee, or from another third party, by sale, trade, license agreement, or other means. If this happens:

(a) The third-party recipient of the data and information assumes the obligations under this part, except for the notification provisions of § 580.50(a) and is subject to the penalty provisions of § 580.32(a)(1) and 30 CFR 550, subpart N; and

(b) A permittee or third party that sells, trades, licenses, or otherwise provides data and information to a third party must advise the recipient, in writing, that accepting these obligations is a condition precedent of the sale, trade, license, or other agreement; and

(c) Except for license agreements, a permittee or third party that sells, trades, or otherwise provides data and information to a third party must advise the Regional Director, in writing within 30 days of the sale, trade, or other agreements, including the identity of the recipient of the data and information; or

(d) For license agreements, a permittee or third party that licenses data and information to a third party must, within 30 days of a request by the Regional Director, advise the Regional Director, in writing, of the license agreement, including the identity of the recipient of the data and information.

REIMBURSEMENT

§ 580.60 Which of my costs will be reimbursed?

(a) We will reimburse you or a third party for reasonable costs of reproducing data and information that the Regional Director requests if:

(1) You deliver G&G data and information to us for the Regional Director to inspect or select and retain (according to §§ 580.40 and 580.50);

(2) We receive your request for reimbursement and the Regional Director determines that the requested reimbursement is proper; and

(3) The cost is at your lowest rate (or a third party's) or at the lowest commercial rate established in the area, whichever is less.

(b) We will reimburse you or the third party for the reasonable costs of processing geophysical information (which does not include cost of data acquisition) if, at the request of the Regional Director, you processed the geophysical data or information in a form or manner other than that used in the normal conduct of business.

§ 580.61 Which of my costs will not be reimbursed?

(a) When you request reimbursement, you must identify reproduction and processing costs separately from acquisition costs.

(b) We will not reimburse you or a third party for data acquisition costs or for the costs of analyzing or processing geological information or interpreting geological or geophysical information.

PROTECTIONS

§ 580.70 What data and information will be protected from public disclosure?

In making data and information available to the public, the Regional Director will follow the applicable requirements of:

(a) The Freedom of Information Act (5 U.S.C. 552);

(b) The implementing regulations at 43 CFR part 2;

(c) The Act; and

(d) The regulations at 30 CFR parts 550 and 552.

(1) If the RD determines that any data or information is exempt from disclosure under the Freedom of Information Act, we will not disclose the data and information unless either:

(i) You and all third parties agree to the disclosure; or

(ii) A provision of 30 CFR parts 550 and 552 allows us to make the disclosure.

(2) We will keep confidential the identity of third-party recipients of data and information collected under a permit. We will not release the identity unless you and the third parties agree to the disclosure.

(3) When you detect any significant hydrocarbon occurrences or environmental hazards on unleased lands during drilling operations, the Regional Director will immediately issue a public announcement. The announcement must further the National interest without unduly damaging your competitive position.

§ 580.71 What is the timetable for release of data and information?

We will release data and information that you or a third party submits and we retain according to paragraphs (a) and (b) of this section.

(a) If the data and information are not related to a deep stratigraphic test, we will release them to the public according to items (1), (2), and (3) in the following table:

If you or a third party submits and we retain . . .	The Regional Director will disclose them to the public . . .
(1) Geological data and information,	10 years after issuing the permit.
(2) Geophysical data,	50 years after you or a third party submit the data.
(3) Geophysical information,	25 years after you or a third party submit the information.
(4) Data and information related to a deep stratigraphic test,	25 years after you complete the test, unless the provisions of paragraph (b) of this section apply.

(b) This paragraph applies if you are covered by paragraph (a)(4) of this section and a lease sale is held or a noncompetitive agreement is negotiated after you complete a test well. We will release the data and information related to the deep stratigraphic test at the earlier of the following times:

(1) Twenty-five years after you complete the test; or

(2) Sixty calendar days after we issue a lease, located partly or totally within 50 geographic miles (92.7 kilometers) of the test.

§ 580.72 What procedure will BOEM follow to disclose acquired data and information to a contractor for reproduction, processing, and interpretation?

(a) When practical, the Regional Director will advise the person who submitted data and information under § 580.40 or § 580.50 of the intent to provide the data or information to an independent contractor or agent for reproduction, processing, and interpretation.

(b) The person notified will have at least five working days to comment on the action.

(c) When the Regional Director advises the person who submitted the data and information, all other owners of the data or information will be considered to have been notified.

(d) The independent contractor or agent must sign a written commitment not to sell, trade, license, or disclose data or information to anyone without the Regional Director's consent.

§ 580.73 Will BOEM share data and information with coastal States?

(a) We can disclose proprietary data, information, and samples submitted to us by permittees or third parties that

we receive under this part to the Governor of any adjacent State that requests it according to paragraphs (b), (c), and (d) of this section. The permittee or third parties who submitted proprietary data, information, and samples will be notified about the disclosure and will have at least five working days to comment on the action.

(b) We will make a disclosure under this section only after the Governor and the Secretary have entered into an agreement containing all of the following provisions:

(1) The confidentiality of the information will be maintained.

(2) In any action taken for failure to protect the confidentiality of proprietary information, neither the Federal Government nor the State may raise as a defense:

(i) Any claim of sovereign immunity; or

(ii) Any claim that the employee who revealed the proprietary information was acting outside the scope of his/her employment in revealing the information.

(3) The State agrees to hold the Federal Government 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.

(4) The materials containing the proprietary data, information, and samples will remain the property of the Federal Government.

(c) The data, information, and samples available for reproduction to the State(s) under an agreement must be related to leased lands. Data and information on unleased lands may be viewed but not copied or reproduced.

(d) The State must return to us the materials containing the proprietary data, information, and samples when we ask for them or when the State no longer needs them.

(e) Information received and knowledge gained by a State official under paragraph (d) of this section is subject to confidentiality requirements of:

(1) The Act; and

(2) The regulations at 30 CFR parts 580, 581, and 582.

Subpart E—Information Collection

§ 580.80 Paperwork Reduction Act statement—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.* and assigned OMB control number 1010–0072. The title of this information collection is ''30 CFR part 580, Prospecting for Minerals other than Oil, Gas, and Sulphur on the Outer Continental Shelf.''

(b) We 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) We use the information collected under this part to:

(1) Evaluate permit applications and monitor scientific research activities for environmental and safety reasons.

(2) Determine that prospecting does not harm resources, result in pollution, create hazardous or unsafe conditions, or interfere with other users in the area.

(3) Approve reimbursement of certain expenses.

(4) Monitor the progress and activities carried out under an OCS prospecting permit.

(5) Inspect and select G&G data and information collected under an OCS prospecting permit.

(d) Respondents are Federal OCS permittees and notice filers. Responses are mandatory or are required to obtain or retain a benefit. We will protect information considered proprietary under applicable law and under regulations at § 580.70 and 30 CFR part 581.

(e) 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, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57098, Sept. 22, 2015]

PART 581—LEASING OF MINERALS OTHER THAN OIL, GAS, AND SULPHUR IN THE OUTER CONTINENTAL SHELF

Subpart A—General

Sec.
581.0 Authority for information collection.
581.1 Purpose and applicability.
581.2 Authority.
581.3 Definitions.
581.4 Qualifications of lessees.
581.5 False statements.
581.6 Appeals.
581.7 Disclosure of information to the public.
581.8 Rights to minerals.
581.9 Jurisdictional controversies.

Subpart B—Leasing Procedures

581.11 Unsolicited request for a lease sale.
581.12 Request for OCS mineral information and interest.
581.13 Joint State/Federal coordination.
581.14 OCS mining area identification.
581.15 Tract size.
581.16 Proposed leasing notice.
581.17 Leasing notice.
581.18 Bidding system.
581.19 Lease term.
581.20 Submission of bids.
581.21 Award of leases.
581.22 Lease form.
581.23 Effective date of leases.

Subpart C—Financial Considerations

581.26 Payments.
581.27 Annual rental.
581.28 Royalty.
581.29 Royalty valuation.
581.30 Minimum royalty.
581.31 Overriding royalties.
581.32 Waiver, suspension, or reduction of rental, minimum royalty, or production royalty.
581.33 Bonds and bonding requirements.

Subpart D—Assignments and Lease Extensions

581.40 Assignment of leases or interests therein.
581.41 Requirements for filing for transfers.
581.42 Effect of assignment on particular lease.
581.43 Effect of suspensions on lease term.

Subpart E—Termination of Leases

581.46 Relinquishment of leases or parts of leases.
581.47 Cancellation of leases.

AUTHORITY: Section 104, Public Law 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Public Law 109–432, Div C, Title I, 120 Stat. 3000; 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334; 33 U.S.C. 2704, 2716; E.O. 12777, as amended; 43 U.S.C. 1331 *et seq.*, 43 U.S.C. 1337.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General

§ 581.0 Authority for information collection.

The information collection requirements contained in part 581 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. An applicant must respond to obtain or retain a benefit.

§ 581.1 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.

§ 581.2 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)).

§ 581.3 Definitions.

When used in this part, the following terms shall have the following meaning:

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 Bureau of Ocean Energy Management (BOEM) 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.

§ 581.4 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.

§ 581.5 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.

§ 581.6 Appeals.

Any party adversely affected by a decision of a BOEM official made pursuant to the provisions of this part shall have the right of appeal pursuant to 30 CFR part 590, except as provided otherwise in § 581.21 of this part.

§ 581.7 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 580, 582, and 43 CFR part 2).

§ 581.8 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 under 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.

§ 581.9 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

§ 581.11 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.

§ 581.12 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 § 581.11, 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.

§ 581.13 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 arrangements 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).

§ 581.14 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 § 581.13 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.

§ 581.15 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.

§ 581.16 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 § 581.13 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.

§ 581.17 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.

§ 581.18 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 § 581.33.

§ 581.19 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.

§ 581.20 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 a BOEM 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 a BOEM 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 a BOEM 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 BOEM at the lease sale prior to the offering of an oral bid.

§ 581.21 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 § 581.26 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 § 581.33. 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.

§ 581.22 Lease form.

The OCS mineral leases shall be issued on the lease form prescribed by the Secretary in the leasing notice.

§ 581.23 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

§ 581.26 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, commercial check, bank draft, money order, certified check, or cashier's check made payable to ''Department of the Interior—BOEM.'' 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 must 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 Production and Royalty Report (P&R) (Form ONRR–4430) in accordance with 30 CFR 1210.201 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 § 581.28(b) on this part) of OCS minerals produced (sold, transferred, used, or otherwise disposed of) from the leasehold.

(h)(1) Unless stated otherwise in the lease, product valuation will be in accordance with the regulations in part 1206 of chapter XII. The value used in the computation of royalty shall be determined by the Director of the Office of Natural Resources Revenue. 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:

(i) The price received by the lessee;

(ii) Commodity and spot market transactions;

(iii) Any other valuation method proposed by the lessee and approved by the Director; and

(iv) Value or cost netback.

(2) 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 forms and maintain auditable records in accordance with 30 CFR chapter XII, Subchapter A—Natural Resources Revenue.

§ 581.27 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 § 581.28.

(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.

§ 581.28 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. Unless stated otherwise in the lease, product valuation will be in accordance with the regulations in part 1206 of chapter XII. The value used in the computation of royalty shall be determined by the Director of the Office of Natural Resources Revenue.

(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.

§ 581.29 Royalty valuation.

Unless stated otherwise in the leasing notice and subsequently issued lease, product valuation will be in accordance with the regulations in part 1206 of chapter XII. The value used in the computation of royalty shall be determined by the Director of the Office of Natural Resources Revenue.

§ 581.30 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 § 581.28(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.

§ 581.31 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 § 581.30 of this part, paragraph (a) of this section, and § 581.32 of this part.

§ 581.32 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.

§ 581.33 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 Deputy Director. 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 § 582.40 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.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57098, Sept. 22, 2015]

Subpart D—Assignments and Lease Extensions

§ 581.40 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.

§ 581.41 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 will not be accepted unless a nonrefundable fee of $50 is paid electronically through *Pay.gov* at: *https://www.pay.gov/paygov/* and a copy of the *Pay.gov* confirmation receipt page is included with your application. For any document you are not required to file by these regulations but which you submit for record purposes, you must also pay electronically through *Pay.gov* a nonrefundable fee of $50 per lease affected, and you must include a copy of the *Pay.gov* confirmation receipt page with your document. 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 § 581.20 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 § 582.40 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.

§ 581.42 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.

§ 581.43 Effect of suspensions on lease term.

(a) If the BSEE 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 BSEE 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

§ 581.46 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.

§ 581.47 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 582—OPERATIONS IN THE OUTER CONTINENTAL SHELF FOR MINERALS OTHER THAN OIL, GAS, AND SULPHUR

Subpart A—General

Sec.
582.0 Authority for information collection.
582.1 Purpose and authority.
582.2 Scope.
582.3 Definitions.
582.4 Opportunities for review and comment.
582.5 Disclosure of data and information to the public.
582.6 Disclosure of data and information to an adjacent State.
582.7 Jurisdictional controversies.

Subpart B—Jurisdiction and Responsibilities of Director

582.10 Jurisdiction and responsibilities of Director.
582.11 Director's authority.
582.12 Director's responsibilities.
582.13 [Reserved]
582.14 Noncompliance, remedies, and penalties.
582.15 Cancellation of leases.

Subpart C—Obligations and Responsibilities of Lessees

582.20 Obligations and responsibilities of lessees.
582.21 Plans, general.
582.22 Delineation Plan.
582.23 Testing Plan.
582.24 Mining Plan.
582.25 Plan modification.
582.26 Contingency Plan.
582.27 Conduct of operations.
582.28 Environmental protection measures.
582.29 Reports and records.
582.30 Right of use and easement.
582.31 [Reserved]

Subpart D—Payments

582.40 Bonds.
582.41 Method of royalty calculation.
582.42 Payments.

Subpart E—Appeals

582.50 Appeals.

AUTHORITY: Section 104, Public Law 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Public Law 109–432, Div C, Title I, 120 Stat. 3000; 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334; 33 U.S.C. 2704, 2716; E.O. 12777, as amended; 43 U.S.C. 1331 *et seq.*, 43 U.S.C. 1337.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General

§ 582.0 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 Bureau of Ocean Energy Management (BOEM) of general mining operations in the Outer Continental Shelf (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.

§ 582.1 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 BOEM.

§ 582.2 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.

§ 582.3 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 BOEM 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 overlying 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 include 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.

§ 582.4 Opportunities for review and comment.

(a) In carrying out BOEM'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).

§ 582.5 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.

§ 582.6 Disclosure of data and information to an adjacent State.

(a) Proprietary data, information, and samples submitted to BOEM 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.

§ 582.7 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

§ 582.10 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 30 CFR part 581, 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.

§ 582.11 Director's authority.

(a) In the exercise of jurisdiction under § 582.10, 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.

§ 582.12 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 § 582.4(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 § 582.4(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 § 582.4(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)–(f) [Reserved]

(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 § 581.26(i) of this chapter.

(h) [Reserved]

§ 582.13 [Reserved]

§ 582.14 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 30 CFR part 550 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)).

§ 582.15 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

§ 582.20 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 30 CFR part 581. 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 § 582.29 of this part.

(h) When an oral approval is given by BOEM 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 BOEM, BSEE or other Agencies needed to carry out exploration, testing, development, and production activities under a lease issued under 30 CFR part 581 of this title.

§ 582.21 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.

§ 582.22 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 samples 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 § 582.28(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.

§ 582.23 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 § 582.28(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.

§ 582.24 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 § 582.28(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.

§ 582.25 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 §§ 582.21, 582.22, 582.23, and 582.24 of this part.

§ 582.26 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 § 582.28(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.

§ 582.27 Conduct of operations.

(a)–(h) [Reserved]

(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)–(m) [Reserved]

§ 582.28 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 30 CFR 250.194, §§ 550.194, 550.218, 550.249, and 550.303.

(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) [Reserved]

(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)–(4) [Reserved]

(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) [Reserved]

(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.

§ 582.29 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 § 582.28 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.

§ 582.30 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.

§ 582.31 [Reserved]

Subpart D—Payments

§ 582.40 Bonds.

(a) Pursuant to the requirements for a bond in § 581.33 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 Deputy Director. 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 § 556.58(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 three areas:

(1) The Gulf of Mexico and the area offshore the Atlantic Ocean;

(2) The area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; and

(3) The area offshore the coast of Alaska.

(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.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57098, Sept. 22, 2015]

§ 582.41 Method of royalty calculation.

In the event that the provisions of royalty management regulations in part 1206 of chapter XII do not apply to the specific commodities produced under regulations in this part, the lessee shall comply with procedures specified in the leasing notice.

§ 582.42 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 § 581.26.

Subpart E—Appeals

§ 582.50 Appeals.

See 30 CFR part 590 for instructions on how to appeal any order or decision that we issue under this part.

PART 583—NEGOTIATED NONCOMPETITIVE AGREEMENTS FOR THE USE OF OUTER CONTINENTAL SHELF SAND, GRAVEL, AND/OR SHELL RESOURCES

Subpart A—General

Sec.
583.100 What is BOEM's authority for information collection (IC)?
583.105 What is the purpose of this part and to whom does it apply?
583.110 What is BOEM's authority for this part?
583.115 What definitions do I need to know?
583.120 Who is qualified for a project?
583.125 What are my rights to seek reconsideration of an unfavorable decision by BOEM?
583.130 What are the minimum contents of an agreement to use OCS sand, gravel, and/or shell resources?

Subpart B—[Reserved]

Subpart C—Outer Continental Shelf Sand, Gravel, and/or Shell Resources Negotiated Agreements

583.300 How do I submit a request for an agreement?
583.305 How will BOEM determine if a project qualifies?
583.310 What process does BOEM use to technically and environmentally evaluate a qualified project?
583.315 What is the process for negotiating and executing an agreement?
583.320 What kinds of information must be included in an agreement?
583.325 What is the effective date of an agreement?
583.330 How will BOEM enforce the agreement?
583.335 What is the term of the agreement?
583.340 What debarment or suspension obligations apply to transactions and contracts related to a project?
583.345 What is the process for extending or modifying an agreement?
583.350 When can an agreement be terminated?

AUTHORITY: 43 U.S.C. 1334.

SOURCE: 82 FR 45973, Oct. 3, 2017, unless otherwise noted.

Subpart A—General

§ 583.100 What is BOEM's authority for information collection (IC)?

The IC requirements contained in part 583 have been approved by OMB

under 44 U.S.C. 3501 and assigned control number 1010–0191. The information is being collected to determine if the applicant for a negotiated noncompetitive agreement (agreement) for the use of sand, gravel, and/or shell resources on the Outer Continental Shelf (OCS) is qualified to enter into such an agreement and to determine if the requested action is warranted. Applicants and parties to an agreement are required to respond to requests related to IC activities.

§ 583.105 What is the purpose of this part and to whom does it apply?

The regulations in this part provide procedures for entering into negotiated noncompetitive agreements for the use of OCS sand, gravel, and/or shell resources. The rules of this part apply exclusively to negotiated noncompetitive use of OCS sand, gravel, and/or shell resources and do not apply to competitive leasing of minerals, including oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals that 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, as amended (43 U.S.C. 1701 *et seq.*).

§ 583.110 What is BOEM's authority for this part?

(a) Pursuant to authority granted by section 8(k) of the Outer Continental Shelf Lands Act (OSCLA), as amended (43 U.S.C. 1337(k)), the Secretary has authority to negotiate a noncompetitive agreement for the use of OCS sand, gravel, and/or shell resources:

(1) In a program of, or project for, shore protection, beach restoration, or coastal wetlands restoration undertaken by a Federal, State, or local government agency; or

(2) In a construction project, other than a project described in paragraph (a)(1) of this section, that is funded in whole or in part by or authorized by the Federal Government.

(b) The Secretary has delegated authority to BOEM to administer the negotiated noncompetitive agreement provisions of OCSLA and prescribe the rules and regulations necessary to carry out those provisions.

§ 583.115 What definitions do I need to know?

The definitions at 30 CFR 550.105 apply to this part. In addition, when used in this part, the following terms will have the meaning given below:

Agreement means a negotiated noncompetitive agreement that authorizes a person to use OCS sand, gravel, and/or shell resources in a program of, or project for, shore protection, beach restoration or coastal wetlands restoration undertaken by one or more Federal, state or local government agencies, or in a construction project authorized by, or funded in whole or in part by, the Federal government. The form of the agreement will be a Memorandum of Agreement (if one or more of the parties to the agreement, other than BOEM, is a Federal agency) or a lease (if all of the parties to the agreement other than BOEM are non-Federal agencies or persons).

Amendment means a modification to the agreement between BOEM and the parties to the agreement that extends or modifies the terms of the agreement.

Applicant means any person proposing to use OCS sand, gravel, and/or shell resources for a shore protection, beach restoration or coastal wetlands restoration project undertaken by a Federal, state or local government agency, or a construction project authorized by, or funded in whole or in part by, the Federal Government. If multiple persons or Federal, state, or local governments, other than BOEM, partner on a project they will be considered joint applicants.

BOEM means the Bureau of Ocean Energy Management of the U.S. Department of the Interior (DOI).

Borrow area means the offshore geographic area(s) or region(s) where OCS sand, gravel, and/or shell resources have been identified for potential use in a specific project.

Federal agency means any department, agency, or instrumentality of the United States.

Local government means the governing authority at the county or city level with jurisdiction to administer a particular project(s).

Modification means the process whereby parties to an agreement and

BOEM mutually agree to change, alter or amend an existing agreement.

Placement area means the geographic area in which OCS sand, gravel, and/or shell resources, used by agreement, will be placed pursuant to that agreement.

Program means a group of related projects that may be the subject of a negotiated noncompetitive agreement for the use of OCS sand, gravel, and/or shell resources.

Project means an undertaking that may be the subject of a negotiated noncompetitive agreement for the use of OCS sand, gravel, and/or shell resources.

Secretary means the Secretary of the Interior.

§ 583.120 Who is qualified for a project?

(a) BOEM may enter into an agreement with any person proposing to use OCS sand, gravel, and/or shell resources for a program of, or project for, shore protection, beach restoration, or coastal wetlands restoration undertaken by a Federal, state, or local government agency or in a construction project that is funded in whole or in part by or authorized by the Federal Government.

(b) To request an agreement under this part, the applicant must be:

(1) A Federal, state, or local government agency;

(2) A citizen or national of the United States;

(3) An alien lawfully admitted for permanent residence in the United States, as defined in the Immigration and Nationality Act, as amended (8 U.S.C. 1101(a)(20));

(4) A private or public corporation organized under the laws of the United States, or of any State or territory thereof; or

(5) An association of such citizens, nationals, resident aliens, or private or public corporations.

(c) When entering into an agreement under this part, all applicants are subject to the requirements of 2 CFR part 180 and 2 CFR part 1400.

§ 583.125 What are my rights to seek reconsideration of an unfavorable decision by BOEM?

(a) After being notified of disqualification or disapproval of an agreement or modification, an unsuccessful applicant, or adversely affected party to an agreement, may apply for reconsideration by the Director.

(1) All applications for reconsideration must be submitted to the Director within 15 days of being notified of disqualification or disapproval of an agreement or modification, and must be accompanied by a statement of reasons for the requested reconsideration, with one copy also submitted to the program office whose decision is the subject of the request for reconsideration.

(2) The Director will respond in writing within 30 days.

(b) No appeal rights are available under 30 CFR part 590 and 43 CFR part 4, subpart E.

§ 583.130 What are the minimum contents of an agreement to use OCS sand, gravel, and/or shell resources?

Any use of OCS sand, gravel, and/or shell resources in an agreement will be negotiated on a case-by-case basis. The agreement will specify, at a minimum, who may use the OCS sand, gravel, and/or shell resources; the nature of the rights granted, including any terms and conditions and environmental stipulations; and the location, type, and volume of OCS sand, gravel, and/or shell resources. An authorization to use OCS sand, gravel, and/or shell resources identified in an agreement is not exclusive; BOEM may allow other entities to use OCS sand, gravel, and/or shell resources from the same borrow area if these uses are determined by BOEM to be non-conflicting and do not exceed the availability of the OCS resource.

Subpart B—[Reserved]

Subpart C—Outer Continental Shelf Sand, Gravel, and/or Shell Resources Negotiated Agreements

§ 583.300 How do I submit a request for an agreement?

Any person may submit a written request to BOEM to obtain an agreement for the use of OCS sand, gravel, and/or shell resources for use in a program of, or project for, shore protection, beach restoration, or coastal wetlands restoration undertaken by a Federal, state, or local government agency, or in a construction project that is funded in whole or in part by or authorized by the Federal Government.

(a) The written request must include:

(1) A detailed description of the proposed project for which the OCS sand, gravel, and/or shell resources will be used and how it qualifies as a program or project eligible under OCSLA to use OCS sand, gravel, or shell resources;

(2) A description of the proposed borrow area(s) and placement area(s), along with maps with geographic coordinates depicting the location of the desired borrow area(s), the OCS block number(s), OCS Planning Area(s), OCS Protraction Diagram Designation(s), and the placement area(s). These should include:

(i) A detailed set of digital (e.g., portable document format or pdf) maps with coordinates and navigation features of the desired OCS project area (including borrow area and other project features); and

(ii) Digital geo-referenced spatial and tabular data depicting the borrow area with features, such as geological sampling locations and any hard or live-bottom benthic habitat present;

(3) Any available geological and geophysical data used to select, design, and delineate the borrow area(s) and potential borrow areas considered but not selected for final design in digital format, geo-referenced where relevant. These may include:

(i) Sediment sampling (sediment cores and grab samples) data such as physical description sheets, photographs, core locations, and grain size analysis; and

(ii) Geophysical data such as subbottom profiler, marine magnetometer, and side-scan sonar data, and bathymetry including geo-referenced navigation survey tracklines, shotpoints, and/or timestamps;

(4) Any other uses of the OCS or infrastructure in the borrow area that are known to the applicant at the time of application submittal;

(5) A description of the environmental evaluations and corresponding documents that have been completed or are being prepared that cover all offshore and onshore components of the project, as applicable;

(6) A target date or date range when the OCS sand, gravel, and/or shell resources will be needed;

(7) A description of the person or government entities undertaking the project;

(8) A list of any permits, licenses or authorizations required for the project and their current status;

(9) A description of any potential inconsistencies with state coastal zone management plans and/or any other applicable state and local statutes, regulations or ordinances;

(10) The name, title, telephone number, mailing address and email address of any points of contact for any Federal agencies, state, or local governments, and contractor(s) with whom the applicant has contracted or intends to contract;

(11) A statement explaining who authorized the project and how the project is to be funded, indicating whether the project is federally funded, in whole or in part, and whether the project is authorized by the Federal Government; and

(12) For any other Federal, state, or local government agency identified in the application, the name, title, mailing address, telephone number, and email address of both a primary and a secondary point of contact for the agency.

(b) [Reserved]

§ 583.305 How will BOEM determine if a project qualifies?

BOEM will make a determination as to whether the project, as described in § 583.300, qualifies for a negotiated noncompetitive agreement for the use of

OCS sand, gravel, and/or shell resources. Within 15 business days of receipt of the application, BOEM will determine if the application is complete or will request additional information. After it has determined the application is complete, BOEM will review the application and notify the applicant in writing whether the project qualifies for an agreement. In determining whether a project qualifies for an agreement, BOEM will consider, among other criteria, the following:

(a) The project purpose;

(b) Other uses of OCS sand, gravel, and/or shell resources from the same borrow area that are currently or were previously authorized by BOEM for other projects or programs, including the location, type and volume of such resources;

(c) The project funding source(s) and amounts;

(d) The proposed design and feasibility of the project;

(e) Any potential environmental and safety risks associated with the project;

(f) Other federal interests located near or within the specified borrow area;

(g) Comments received from potentially affected state or local governments, if any;

(h) The applicant's background and experience working on similar projects or activities;

(i) Whether the project operations can be conducted in a manner that protects the environment and promotes orderly development of OCS mineral resources;

(j) Whether activities can be conducted in a manner that does not pose a threat of serious harm or damage to, or waste of, any natural resource, any life (including fish and other aquatic life), property, or the marine, coastal, or human environment; and

(k) Whether the project is consistent with the requirements of applicable statutes and their implementing regulations, which may include, but are not limited to, the Endangered Species Act (ESA) (16 U.S.C. 1531 *et seq.*), the Marine Mammal Protection Act (MMPA) (16 U.S.C. 1361 *et seq.*), the Marine Debris Research, Prevention, and Reduction Act (MDRPRA) (33 U.S.C. 1951 *et seq.*), the Marine Plastic Pollution Research and Control Act (MPPRCA) (33 U.S.C. 1901 *et seq.*), the Federal Water Pollution Control Act (FWPCA) (33 U.S.C. 1381 *et seq.*), and the International Convention for the Prevention of Pollution from Ships (MARPOL), MARPOL-Annex V Treaty.

§ 583.310 What process does BOEM use to technically and environmentally evaluate a qualified project?

(a) Once BOEM has determined a project qualifies for an agreement, BOEM will begin the project evaluation process to decide whether to enter into a negotiated noncompetitive agreement.

(b) BOEM will coordinate with relevant Federal agencies, State, and local governments and any potentially affected federally recognized Indian tribes or Alaska Native Corporations in the project evaluation.

(c) BOEM will evaluate the project and additional information provided pursuant to §§ 583.300 and 583.305, to determine if the information is sufficient to conduct necessary technical and environmental reviews to comply with the requirements of applicable statutes and regulations, which may include, but are not limited to: OCSLA (43 U.S.C. 1331 *et seq.*), the National Environmental Policy Act (NEPA) (42 U.S.C. 4321 *et seq.*), the ESA (16 U.S.C. 1531 *et seq.*), the MMPA (16 U.S.C. 1361 *et seq.*), the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA) (16 U.S.C. 1801 *et seq.*), the National Historic Preservation Act (NHPA) (54 U.S.C. 300101 *et seq.*), and the Coastal Zone Management Act (CZMA) (16 U.S.C. 1451 *et seq.*).

(d) BOEM will not enter into a negotiated noncompetitive agreement with the applicant until the information requested for the evaluation has been provided and BOEM has evaluated it.

§ 583.315 What is the process for negotiating and executing an agreement?

(a) Upon completion of the technical, environmental and other evaluations established in §§ 583.305 and 583.310, BOEM will decide whether to enter into a negotiated noncompetitive agreement with the applicant for use of

OCS sand, gravel, or shell resources for its proposed project.

(b) If BOEM decides not to enter into such an agreement, BOEM will inform the applicant of its reasons for not doing so. An applicant may ask the BOEM Director for reconsideration of this decision, in accordance with § 583.125(a).

(c) If BOEM has decided to enter into a negotiated noncompetitive agreement with the applicant, BOEM will negotiate the terms and conditions of the agreement with the applicant and prepare a draft agreement for the applicant's review.

(d) After considering comments and suggestions from the applicant, BOEM, at its discretion, may finalize the agreement and distribute it to the applicant for signature.

(e) Upon receipt of the agreement with the applicant's signature, BOEM will execute the agreement. A copy of the executed agreement will be mailed to the parties.

§ 583.320 What kinds of information must be included in an agreement?

Every agreement is negotiated on a case-by-case basis, but at a minimum, must include:

(a) An agreement number, as assigned by BOEM;

(b) The purpose of, and authorities for, the agreement;

(c) Designated and delineated borrow area(s);

(d) A project description, including the timeframe within which the project is to be started and completed;

(e) The terms and conditions of the agreement, including any reporting requirements, environmental mitigations, and operating parameters;

(f) All obligations of the parties; and

(g) The signatures of appropriate individuals authorized to bind the applicant and BOEM.

§ 583.325 What is the effective date of an agreement?

The agreement will become effective on the date when all parties to the agreement have signed it.

§ 583.330 How will BOEM enforce the agreement?

(a) Failure to comply with any applicable law or any provision, term, or condition of the agreement may result in the termination of the agreement, a referral to an appropriate Federal or State agency for enforcement, or both. Termination of the agreement for noncompliance will be in the sole discretion of the Director.

(b) The failure to comply in a timely and satisfactory manner with any provision, term or condition of the agreement may delay or prevent BOEM's approval of future requests for use of OCS sand, gravel, and/or shell resources on the part of the parties to the agreement.

§ 583.335 What is the term of the agreement?

(a) An agreement will terminate upon one of the following, whichever occurs first:

(1) The agreement expires by its own terms, unless the term is extended prior to expiration under § 583.345;

(2) The project is terminated, as set forth in § 583.350; or

(3) A party to the agreement notifies BOEM, in writing, that sufficient OCS sand, gravel, and/or shell resources, up to the amount authorized in the agreement, have been obtained to complete the project.

(b) Absent extraordinary circumstances, no agreement will be for a term longer than five years from its effective date.

§ 583.340 What debarment or suspension obligations apply to transactions and contracts related to a project?

The parties to an agreement must ensure that all contracts and transactions related to an agreement issued under this part comply with the suspension and debarment regulations in 2 CFR part 180 and 2 CFR part 1400.

§ 583.345 What is the process for extending or modifying an agreement?

(a) Unless otherwise provided for in the agreement, the parties to the agreement may submit to BOEM a written request to extend or modify an

agreement. BOEM is under no obligation to extend or modify an agreement and cannot be held liable for the consequences of the expiration of an agreement. With the exception of paragraph (b) of this section, any such requests must be made at least 180 days before the term of the agreement expires. BOEM will respond to the request for modification within 30 days of receipt and request any necessary information and evaluations to comply with § 583.305. BOEM may approve the request, disapprove it, or approve it with modifications subject to the requirements of § 583.305.

(1) If BOEM approves a request to extend or modify an agreement, BOEM will draft an agreement modification for review by the parties to the agreement in the form of an amendment to the original agreement. The amendment will include:

(i) The agreement number, as assigned by BOEM;

(ii) The modification(s) agreed to;

(iii) Any additional mitigation required; and

(iv) The signatures of the parties to the agreement and BOEM.

(2) If BOEM disapproves a request to extend or modify an agreement, BOEM will inform the parties to the agreement of the reasons in writing. Parties to the agreement may ask the BOEM Director for reconsideration in accordance with § 583.125.

(b) By written request, for strictly minor modifications that do not change the substance of the project or the analyzed environmental effects of the project, including but not limited to, the change of a business address, the substitution of a different Federal, State or local government agency contact, or an extension of less than 30 days, parties to the agreement may memorialize the minor modification in a letter from BOEM to the parties indicating the request has been granted.

§ 583.350 When can an agreement be terminated?

(a) The Director will terminate any agreement issued under this part upon proof that it was obtained by fraud or misrepresentation, after notice and an opportunity to be heard has been afforded to the parties of the agreement.

(b) The Director may immediately suspend and subsequently terminate any agreement issued under this part when:

(1) There is noncompliance with the agreement, pursuant to § 583.330 (a); or

(2) It is necessary for reasons of national security or defense; or

(3) The Director determines that:

(i) Continued activity under the agreement would cause serious harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(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 termination outweigh the advantages of continuing the agreement.

(c) The Director will immediately notify the parties to the agreement of the suspension or termination. The Director will also mail a letter to the parties to the agreement at their record post office address with notice of any suspension or termination and the cause for such action.

(d) In the event that BOEM terminates an agreement under this section, none of the parties to the agreement will be entitled to compensation as a result of expenses or lost revenues that may result from the termination.

PART 585—RENEWABLE ENERGY AND ALTERNATE USES OF EXISTING FACILITIES ON THE OUTER CONTINENTAL SHELF

Subpart A—General Provisions

Sec.

585.100 Authority.
585.101 What is the purpose of this part?
585.102 What are BOEM's responsibilities under this part?
585.103 When may BOEM prescribe or approve departures from these regulations?
585.104 Do I need a BOEM lease or other authorization to produce or support the production of electricity or other energy product from a renewable energy resource on the OCS?
585.105 What are my responsibilities under this part?

585.106 Who can hold a lease or grant under this part?
585.107 How do I show that I am qualified to be a lessee or grant holder?
585.108 When must I notify BOEM if an action has been filed alleging that I am insolvent or bankrupt?
585.109 When must I notify BOEM of mergers, name changes, or changes of business form?
585.110 How do I submit plans, applications, reports, or notices required by this part?
585.111 When and how does BOEM charge me processing fees on a case-by-case basis?
585.112 Definitions.
585.113 How will data and information obtained by BOEM under this part be disclosed to the public?
585.114 Paperwork Reduction Act statements—information collection.
585.115 Documents incorporated by reference.
585.116 Requests for information on the state of the offshore renewable energy industry.
585.117 [Reserved]
585.118 What are my appeal rights?

Subpart B—Issuance of OCS Renewable Energy Leases

GENERAL LEASE INFORMATION

585.200 What rights are granted with a lease issued under this part?
585.201 How will BOEM issue leases?
585.202 What types of leases will BOEM issue?
585.203 With whom will BOEM consult before issuance of a lease?
585.204 What areas are available for leasing consideration?
585.205 How will leases be mapped?
585.206 What is the lease size?
585.207–585.209 [Reserved]

COMPETITIVE LEASE PROCESS

585.210 How does BOEM initiate the competitive leasing process?
585.211 What is the process for competitive issuance of leases?
585.212 What is the process BOEM will follow if there is reason to believe that competitors have withdrawn before the Final Sale Notice is issued?
585.213 What must I submit in response to a Request for Interest or a Call for Information and Nominations?
585.214 What will BOEM do with information from the Requests for Information or Calls for Information and Nominations?
585.215 What areas will BOEM offer in a lease sale?
585.216 What information will BOEM publish in the Proposed Sale Notice and Final Sale Notice?
585.217–585.219 [Reserved]

COMPETITIVE LEASE AWARD PROCESS

585.220 What auction format may BOEM use in a lease sale?
585.221 What bidding systems may BOEM use for commercial leases and limited leases?
585.222 What does BOEM do with my bid?
585.223 What does BOEM do if there is a tie for the highest bid?
585.224 What happens if BOEM accepts my bid?
585.225 What happens if my bid is rejected, and what are my appeal rights?
585.226–585.229 [Reserved]

NONCOMPETITIVE LEASE AWARD PROCESS

585.230 May I request a lease if there is no Call?
585.231 How will BOEM process my unsolicited request for a noncompetitive lease?
585.232 May I acquire a lease noncompetitively after responding to a Request for Interest or Call for Information and Nominations?
585.233–585.234 [Reserved]

COMMERCIAL AND LIMITED LEASE TERMS

585.235 If I have a commercial lease, how long will my lease remain in effect?
585.236 If I have a limited lease, how long will my lease remain in effect?
585.237 What is the effective date of a lease?
585.238 Are there any other renewable energy research activities that will be allowed on the OCS?

Subpart C—Rights-of-Way Grants and Rights-of-Use and Easement Grants for Renewable Energy Activities

ROW GRANTS AND RUE GRANTS

585.300 What types of activities are authorized by ROW grants and RUE grants issued under this part?
585.301 What do ROW grants and RUE grants include?
585.302 What are the general requirements for ROW grant and RUE grant holders?
585.303 How long will my ROW grant or RUE grant remain in effect?
585.304 [Reserved]

OBTAINING ROW GRANTS AND RUE GRANTS

585.305 How do I request an ROW grant or RUE grant?
585.306 What action will BOEM take on my request?
585.307 How will BOEM determine whether competitive interest exists for ROW grants and RUE grants?
585.308 How will BOEM conduct an auction for ROW grants and RUE grants?

585.309 When will BOEM issue a noncompetitive ROW grant or RUE grant?
585.310 What is the effective date of an ROW grant or RUE grant?
585.311–585.314 [Reserved]

FINANCIAL REQUIREMENTS FOR ROW GRANTS AND RUE GRANTS

585.315 What deposits are required for a competitive ROW grant or RUE grant?
585.316 What payments are required for ROW grants or RUE grants?

Subpart D—Lease and Grant Administration

NONCOMPLIANCE AND CESSATION ORDERS

585.400 What happens if I fail to comply with this part?
585.401 When may BOEM issue a cessation order?
585.402 What is the effect of a cessation order?
585.403–585.404 [Reserved]

DESIGNATION OF OPERATOR

585.405 How do I designate an operator?
585.406 Who is responsible for fulfilling lease and grant obligations?
585.407 [Reserved]

LEASE OR GRANT ASSIGNMENT

585.408 May I assign my lease or grant interest?
585.409 How do I request approval of a lease or grant assignment?
585.410 How does an assignment affect the assignor's liability?
585.411 How does an assignment affect the assignee's liability?
585.412–585.414 [Reserved]

LEASE OR GRANT SUSPENSION

585.415 What is a lease or grant suspension?
585.416 How do I request a lease or grant suspension?
585.417 When may BOEM order a suspension?
585.418 How will BOEM issue a suspension?
585.419 What are my immediate responsibilities if I receive a suspension order?
585.420 What effect does a suspension order have on my payments?
585.421 How long will a suspension be in effect?
585.422–585.424 [Reserved]

LEASE OR GRANT RENEWAL

585.425 May I obtain a renewal of my lease or grant before it terminates?
585.426 When must I submit my request for renewal?
585.427 How long is a renewal?
585.428 What effect does applying for a renewal have on my activities and payments?
585.429 What criteria will BOEM consider in deciding whether to renew a lease or grant?
585.430–585.431 [Reserved]

LEASE OR GRANT TERMINATION

585.432 When does my lease or grant terminate?
585.433 What must I do after my lease or grant terminates?
585.434 [Reserved]

LEASE OR GRANT RELINQUISHMENT

585.435 How can I relinquish a lease or a grant or parts of a lease or grant?

LEASE OR GRANT CONTRACTION

585.436 Can BOEM require lease or grant contraction?

LEASE OR GRANT CANCELLATION

585.437 When can my lease or grant be canceled?

Subpart E—Payments and Financial Assurance Requirements

PAYMENTS

585.500 How do I make payments under this part?
585.501 What deposits must I submit for a competitively issued lease, ROW grant, or RUE grant?
585.502 What initial payment requirements must I meet to obtain a noncompetitive lease, ROW grant, or RUE grant?
585.503 What are the rent and operating fee requirements for a commercial lease?
585.504 How are my payments affected if I develop my lease in phases?
585.505 What are the rent and operating fee requirements for a limited lease?
585.506 What operating fees must I pay on a commercial lease?
585.507 What rent payments must I pay on a project easement?
585.508 What rent payments must I pay on ROW grants or RUE grants associated with renewable energy projects?
585.509 Who is responsible for submitting lease or grant payments to BOEM?
585.510 May BOEM reduce or waive my lease or grant payments?
585.511–585.514 [Reserved]

FINANCIAL ASSURANCE REQUIREMENTS FOR COMMERCIAL LEASES

585.515 What financial assurance must I provide when I obtain my commercial lease?
585.516 What are the financial assurance requirements for each stage of my commercial lease?

585.517 How will BOEM determine the amounts of the supplemental and decommissioning financial assurance requirements associated with commercial leases?
585.518–585.519 [Reserved]

FINANCIAL ASSURANCE FOR LIMITED LEASES, ROW GRANTS, AND RUE GRANTS

585.520 What financial assurance must I provide when I obtain my limited lease, ROW grant, or RUE grant?
585.521 Do my financial assurance requirements change as activities progress on my limited lease or grant?
585.522–585.524 [Reserved]

REQUIREMENTS FOR FINANCIAL ASSURANCE INSTRUMENTS

585.525 What general requirements must a financial assurance instrument meet?
585.526 What instruments other than a surety bond may I use to meet the financial assurance requirement?
585.527 May I demonstrate financial strength and reliability to meet the financial assurance requirement for lease or grant activities?
585.528 May I use a third-party guaranty to meet the financial assurance requirement for lease or grant activities?
585.529 Can I use a lease- or grant-specific decommissioning account to meet the financial assurance requirements related to decommissioning?

CHANGES IN FINANCIAL ASSURANCE

585.530 What must I do if my financial assurance lapses?
585.531 What happens if the value of my financial assurance is reduced?
585.532 What happens if my surety wants to terminate the period of liability of my bond?
585.533 How does my surety obtain cancellation of my bond?
585.534 When may BOEM cancel my bond?
585.535 Why might BOEM call for forfeiture of my bond?
585.536 How will I be notified of a call for forfeiture?
585.537 How will BOEM proceed once my bond or other security is forfeited?
585.538–585.539 [Reserved]

REVENUE SHARING WITH STATES

585.540 How will BOEM equitably distribute revenues to States?
585.541 What is a qualified project for revenue sharing purposes?
585.542 What makes a State eligible for payment of revenues?
585.543 Example of how the inverse distance formula works.

Subpart F—Plans and Information Requirements

585.600 What plans and information must I submit to BOEM before I conduct activities on my lease or grant?
585.601 When am I required to submit my plans to BOEM?
585.602 What records must I maintain?
585.603–585.604 [Reserved]

SITE ASSESSMENT PLAN AND INFORMATION REQUIREMENTS FOR COMMERCIAL LEASES

585.605 What is a Site Assessment Plan (SAP)?
585.606 What must I demonstrate in my SAP?
585.607 How do I submit my SAP?
585.608–585.609 [Reserved]

CONTENTS OF THE SITE ASSESSMENT PLAN

585.610 What must I include in my SAP?
585.611 What information and certifications must I submit with my SAP to assist BOEM in complying with NEPA and other relevant laws?
585.612 How will my SAP be processed for Federal consistency under the Coastal Zone Management Act?
585.613 How will BOEM process my SAP?

ACTIVITIES UNDER AN APPROVED SAP

585.614 When may I begin conducting activities under my approved SAP?
585.615 What other reports or notices must I submit to BOEM under my approved SAP?
585.616 [Reserved]
585.617 What activities require a revision to my SAP, and when will BOEM approve the revision?
585.618 What must I do upon completion of approved site assessment activities?
585.619 [Reserved]

CONSTRUCTION AND OPERATIONS PLAN FOR COMMERCIAL LEASES

585.620 What is a Construction and Operations Plan (COP)?
585.621 What must I demonstrate in my COP?
585.622 How do I submit my COP?
585.623–585.625 [Reserved]

CONTENTS OF THE CONSTRUCTION AND OPERATIONS PLAN

585.626 What must I include in my COP?
585.627 What information and certifications must I submit with my COP to assist the BOEM in complying with NEPA and other relevant laws?
585.628 How will BOEM process my COP?
585.629 May I develop my lease in phases?
585.630 [Reserved]

ACTIVITIES UNDER AN APPROVED COP

585.631 When must I initiate activities under an approved COP?
585.632 What documents must I submit before I may construct and install facilities under my approved COP?
585.633 How do I comply with my COP?
585.634 What activities require a revision to my COP, and when will BOEM approve the revision?
585.635 What must I do if I cease activities approved in my COP before the end of my commercial lease?
585.636 What notices must I provide BOEM following approval of my COP?
585.637 When may I commence commercial operations on my commercial lease?
585.638 What must I do upon completion of my commercial operations as approved in my COP or FERC license?
585.639 [Reserved]

GENERAL ACTIVITIES PLAN REQUIREMENTS FOR LIMITED LEASES, ROW GRANTS, AND RUE GRANTS

585.640 What is a General Activities Plan (GAP)?
585.641 What must I demonstrate in my GAP?
585.642 How do I submit my GAP?
585.643–585.644 [Reserved]

CONTENTS OF THE GENERAL ACTIVITIES PLAN

585.645 What must I include in my GAP?
585.646 What information and certifications must I submit with my GAP to assist BOEM in complying with NEPA and other relevant laws?
585.647 How will my GAP be processed for Federal consistency under the Coastal Zone Management Act?
585.648 How will BOEM process my GAP?
585.649 [Reserved]

ACTIVITIES UNDER AN APPROVED GAP

585.650 When may I begin conducting activities under my GAP?
585.651 When may I construct complex or significant OCS facilities on my limited lease or any facilities on my project easement proposed under my GAP?
585.652 How long do I have to conduct activities under an approved GAP?
585.653 What other reports or notices must I submit to BOEM under my approved GAP?
585.654 [Reserved]
585.655 What activities require a revision to my GAP, and when will BOEM approve the revision?
585.656 What must I do if I cease activities approved in my GAP before the end of my term?
585.657 What must I do upon completion of approved activities under my GAP?

CABLE AND PIPELINE DEVIATIONS

585.658 Can my cable or pipeline construction deviate from my approved COP or GAP?
585.659 What requirements must I include in my SAP, COP, or GAP regarding air quality?

Subpart G—Facility Design, Fabrication, and Installation

REPORTS

585.700 What reports must I submit to BOEM before installing facilities described in my approved SAP, COP, or GAP?
585.701 What must I include in my Facility Design Report?
585.702 What must I include in my Fabrication and Installation Report?
585.703 What reports must I submit for project modifications and repairs?
585.704 [Reserved]

CERTIFIED VERIFICATION AGENT

585.705 When must I use a Certified Verification Agent (CVA)?
585.706 How do I nominate a CVA for BOEM approval?
585.707 What are the CVA's primary duties for facility design review?
585.708 What are the CVA's or project engineer's primary duties for fabrication and installation review?
585.709 When conducting onsite fabrication inspections, what must the CVA or project engineer verify?
585.710 When conducting onsite installation inspections, what must the CVA or project engineer do?
585.711 [Reserved]
585.712 What are the CVA's or project engineer's reporting requirements?
585.713 What must I do after the CVA or project engineer confirms conformance with the Fabrication and Installation Report on my commercial lease?
585.714 What records relating to SAPs, COPs, and GAPs must I keep?

Subpart H—Environmental and Safety Management, Inspections, and Facility Assessments for Activities Conducted Under SAPs, COPs and GAPs

585.800 How must I conduct my activities to comply with safety and environmental requirements?
585.801 How must I conduct my approved activities to protect marine mammals, threatened and endangered species, and designated critical habitat?
585.802 What must I do if I discover a potential archaeological resource while conducting my approved activities?

585.803 How must I conduct my approved activities to protect essential fish habitats identified and described under the Magnuson-Stevens Fishery Conservation and Management Act?
585.804–585.809 [Reserved]

SAFETY MANAGEMENT SYSTEMS

585.810 What must I include in my Safety Management System?
585.811 When must I follow my Safety Management System?
585.812 [Reserved]

MAINTENANCE AND SHUTDOWNS

585.813 When do I have to report removing equipment from service?
585.814 [Reserved]

EQUIPMENT FAILURE AND ADVERSE ENVIRONMENTAL EFFECTS

585.815 What must I do if I have facility damage or an equipment failure?
585.816 What must I do if environmental or other conditions adversely affect a cable, pipeline, or facility?
585.817–585.819 [Reserved]

INSPECTIONS AND ASSESSMENTS

585.820 Will BOEM conduct inspections?
585.821 Will BOEM conduct scheduled and unscheduled inspections?
585.822 What must I do when BOEM conducts an inspection?
585.823 Will BOEM reimburse me for my expenses related to inspections?
585.824 How must I conduct self-inspections?
585.825 When must I assess my facilities?
585.826–585.829 [Reserved]

INCIDENT REPORTING AND INVESTIGATION

585.830 What are my incident reporting requirements?
585.831 What incidents must I report, and when must I report them?
585.832 How do I report incidents requiring immediate notification?
585.833 What are the reporting requirements for incidents requiring written notification?

Subpart I—Decommissioning

DECOMMISSIONING OBLIGATIONS AND REQUIREMENTS

585.900 Who must meet the decommissioning obligations in this subpart?
585.901 When do I accrue decommissioning obligations?
585.902 What are the general requirements for decommissioning for facilities authorized under my SAP, COP, or GAP?
585.903 What are the requirements for decommissioning FERC-licensed hydrokinetic facilities?
585.904 Can I request a departure from the decommissioning requirements?

DECOMMISSIONING APPLICATIONS

585.905 When must I submit my decommissioning application?
585.906 What must my decommissioning application include?
585.907 How will BOEM process my decommissioning application?
585.908 What must I include in my decommissioning notice?

FACILITY REMOVAL

585.909 When may BOEM authorize facilities to remain in place following termination of a lease or grant?
585.910 What must I do when I remove my facility?
585.911 [Reserved]

DECOMMISSIONING REPORT

585.912 After I remove a facility, cable, or pipeline, what information must I submit?

COMPLIANCE WITH AN APPROVED DECOMMISSIONING APPLICATION

585.913 What happens if I fail to comply with my approved decommissioning application?

Subpart J—Rights of Use and Easement for Energy- and Marine-Related Activities Using Existing OCS Facilities

REGULATED ACTIVITIES

585.1000 What activities does this subpart regulate?
585.1001–585.1003 [Reserved]

REQUESTING AN ALTERNATE USE RUE

585.1004 What must I do before I request an Alternate Use RUE?
585.1005 How do I request an Alternate Use RUE?
585.1006 How will BOEM decide whether to issue an Alternate Use RUE?
585.1007 What process will BOEM use for competitively offering an Alternate Use RUE?
585.1008–585.1009 [Reserved]

ALTERNATE USE RUE ADMINISTRATION

585.1010 How long may I conduct activities under an Alternate Use RUE?
585.1011 What payments are required for an Alternate Use RUE?
585.1012 What financial assurance is required for an Alternate Use RUE?
585.1013 Is an Alternate Use RUE assignable?
585.1014 When will BOEM suspend an Alternate Use RUE?

585.1015 How do I relinquish an Alternate Use RUE?
585.1016 When will an Alternate Use RUE be cancelled?
585.1017 [Reserved]

DECOMMISSIONING AN ALTERNATE USE RUE

585.1018 Who is responsible for decommissioning an OCS facility subject to an Alternate Use RUE?
585.1019 What are the decommissioning requirements for an Alternate Use RUE?

AUTHORITY: Section 104, Public Law 97–451, 96 Stat. 2451 (30 U.S.C. 1714), Public Law 109–432, Div C, Title I, 120 Stat. 3000; 30 U.S.C. 1751; 31 U.S.C. 9701; 43 U.S.C. 1334; 33 U.S.C. 2704, 2716; E.O. 12777, as amended; 43 U.S.C. 1331 *et seq.*, 43 U.S.C. 1337.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—General Provisions

§ 585.100 Authority.

The authority for this part derives from amendments to subsection 8 of the Outer Continental Shelf Lands Act (OCS Lands Act) (43 U.S.C. 1337), as set forth in section 388(a) of the Energy Policy Act of 2005 (EPAct) (Pub. L. 109–58). The Secretary of the Interior delegated to the Bureau of Ocean Energy Management (BOEM) the authority to regulate activities under section 388(a) of the EPAct. These regulations specifically apply to activities that:

(a) Produce or support production, transportation, or transmission of energy from sources other than oil and gas; or

(b) Use, for energy-related purposes or for other authorized marine-related purposes, facilities currently or previously used for activities authorized under the OCS Lands Act.

§ 585.101 What is the purpose of this part?

The purpose of this part is to:

(a) Establish procedures for issuance and administration of leases, right-of-way (ROW) grants, and right-of-use and easement (RUE) grants for renewable energy production on the Outer Continental Shelf (OCS) and RUEs for the alternate use of OCS facilities for energy or marine-related purposes;

(b) Inform you and third parties of your obligations when you undertake activities authorized in this part; and

(c) Ensure that renewable energy activities on the OCS and activities involving the alternate use of OCS facilities for energy or marine-related purposes are conducted in a safe and environmentally sound manner, in conformance with the requirements of subsection 8(p) of the OCS Lands Act, other applicable laws and regulations, and the terms of your lease, ROW grant, RUE grant, or Alternate Use RUE grant.

(d) This part will not convey access rights for oil, gas, or other minerals.

§ 585.102 What are BOEM's responsibilities under this part?

(a) BOEM will ensure that any activities authorized in this part are carried out in a manner that provides for:

(1) Safety;

(2) Protection of the environment;

(3) Prevention of waste;

(4) Conservation of the natural resources of the OCS;

(5) Coordination with relevant Federal agencies (including, in particular, those agencies involved in planning activities that are undertaken to avoid conflicts among users and maximize the economic and ecological benefits of the OCS, including multifaceted spatial planning efforts);

(6) Protection of National security interests of the United States;

(7) Protection of the rights of other authorized users of the OCS;

(8) A fair return to the United States;

(9) Prevention of interference with reasonable uses (as determined by the Secretary or Director) of the exclusive economic zone, the high seas, and the territorial seas;

(10) Consideration of the location of and any schedule relating to a lease or grant under this part for an area of the OCS, and any other use of the sea or seabed;

(11) Public notice and comment on any proposal submitted for a lease or grant under this part; and

(12) Oversight, inspection, research, monitoring, and enforcement of activities authorized by a lease or grant under this part.

(b) BOEM will require compliance with all applicable laws, regulations, other requirements, and the terms of your lease or grant under this part and

approved plans. BOEM will approve, disapprove, or approve with conditions any plans, applications, or other documents submitted to BOEM for approval under the provisions of this part.

(c) Unless otherwise provided in this part, BOEM may give oral directives or decisions whenever prior BOEM approval is required under this part. BOEM will document in writing any such oral directives within 10 business days.

(d) BOEM will establish practices and procedures to govern the collection of all payments due to the Federal Government, including any cost recovery fees, rents, operating fees, and other fees or payments. BOEM will do this in accordance with the terms of this part, the leasing notice, the lease or grant under this part, and applicable Office of Natural Resources Revenue regulations or guidance.

(e) BOEM will provide for coordination and consultation with the Governor of any State, the executive of any local government, and the executive of any Indian Tribe that may be affected by a lease, easement, or ROW under this subsection. BOEM may invite any affected State Governor, representative of an affected Indian Tribe, and affected local government executive to join in establishing a task force or other joint planning or coordination agreement in carrying out our responsibilities under this part.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21621, Apr. 17, 2014]

§ 585.103 When may BOEM prescribe or approve departures from these regulations?

(a) BOEM may prescribe or approve departures from these regulations when departures are necessary to:

(1) Facilitate the appropriate activities on a lease or grant under this part;

(2) Conserve natural resources;

(3) Protect life (including human and wildlife), property, or the marine, coastal, or human environment; or

(4) Protect sites, structures, or objects of historical or archaeological significance.

(b) Any departure approved under this section and its rationale must:

(1) Be consistent with subsection 8(p) of the OCS Lands Act;

(2) Protect the environment and the public health and safety to the same degree as if there was no approved departure from the regulations;

(3) Not impair the rights of third parties; and

(4) Be documented in writing.

§ 585.104 Do I need a BOEM lease or other authorization to produce or support the production of electricity or other energy product from a renewable energy resource on the OCS?

Except as otherwise authorized by law, it will be unlawful for any person to construct, operate, or maintain any facility to produce, transport, or support generation of electricity or other energy product derived from a renewable energy resource on any part of the OCS, except under and in accordance with the terms of a lease, easement, or ROW issued pursuant to the OCS Lands Act.

§ 585.105 What are my responsibilities under this part?

As a lessee, applicant, operator, or holder of a ROW grant, RUE grant, or Alternate Use RUE grant, you must:

(a) Design your projects and conduct all activities in a manner that ensures safety and will not cause undue harm or damage to natural resources, including their physical, atmospheric, and biological components to the extent practicable; and take measures to prevent unauthorized discharge of pollutants including marine trash and debris into the offshore environment.

(b) Submit requests, applications, plans, notices, modifications, and supplemental information to BOEM as required by this part;

(c) Follow up, in writing, any oral request or notification you made, within 3 business days;

(d) Comply with the terms, conditions, and provisions of all reports and notices submitted to BOEM, and of all plans, revisions, and other BOEM approvals, as provided in this part;

(e) Make all applicable payments on time;

(f) Comply with the DOI's nonprocurement debarment regulations at 2 CFR part 1400;

(g) Include the requirement to comply with 2 CFR part 1400 in all contracts and transactions related to a lease or grant under this part;

(h) Conduct all activities authorized by the lease or grant in a manner consistent with the provisions of subsection 8(p) of the OCS Lands Act;

(i) Compile, retain, and make available to BOEM representatives, within the time specified by BOEM, any data and information related to the site assessment, design, and operations of your project; and

(j) Respond to requests from the Director in a timely manner.

§ 585.106 Who can hold a lease or grant under this part?

(a) You may hold a lease or grant under this part if you can demonstrate that you have the technical and financial capabilities to conduct the activities authorized by the lease or grant and you are a(n):

(1) Citizen or national of the United States;

(2) Alien 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 any State of the United States, the District of Columbia, or any territory or insular possession subject to U.S. jurisdiction;

(4) Association of such citizens, nationals, resident aliens, or corporations;

(5) Executive Agency of the United States as defined in section 105 of Title 5 of the U.S. Code;

(6) State of the United States; and

(7) Political subdivision of States of the United States.

(b) You may not hold a lease or grant under this part or acquire an interest in a lease or grant under this part if:

(1) You or your principals are excluded or disqualified from participating in transactions covered by the Federal nonprocurement debarment and suspension system (2 CFR part 1400), unless BOEM explicitly has approved an exception for this transaction;

(2) BOEM determines or has previously determined after notice and opportunity for a hearing that you or your principals have failed to meet or exercise due diligence under any OCS lease or grant; or

(3) BOEM determines or has previously determined after notice and opportunity for a hearing that you:

(i) Remained in violation of the terms and conditions of any lease or grant issued under the OCS Lands Act for a period extending longer than 30 days (or such other period BOEM allowed for compliance) after BOEM directed you to comply; and

(ii) You took no action to correct the noncompliance within that time period.

§ 585.107 How do I show that I am qualified to be a lessee or grant holder?

(a) You must demonstrate your technical and financial capability to construct, operate, maintain, and terminate/decommission projects for which you are requesting authorization. Documentation can include:

(1) Descriptions of international or domestic experience with renewable energy projects or other types of electric-energy-related projects; and

(2) Information establishing access to sufficient capital to carry out development.

(b) An individual must submit a written statement of citizenship status attesting to U.S. citizenship. It does not need to be notarized nor give the age of individual. A resident alien may submit a photocopy of the Immigration and Naturalization Service form evidencing legal status of the resident alien.

(c) A corporation or association must submit evidence, as specified in the table in paragraph (d) of this section, acceptable to BOEM that:

(1) It is qualified to hold leases or grants under this part;

(2) It is authorized to conduct business under the laws of its State;

(3) It is authorized to hold leases or grants on the OCS under the operating rules of its business; and

(4) The persons holding the titles listed are authorized to bind the corporation or association when conducting business with BOEM.

(d) Acceptable evidence under paragraph (c) of this section includes, but is not limited to the following:

Requirements to qualify to hold leases or grants on the OCS:	Corp.	Ltd. Prtnsp.	Gen. Prtnsp.	LLC	Trust
(1) Original certificate or certified copy from the State of incorporation stating the name of the corporation exactly as it must appear on all legal documents.	XX	.....	.....	.....	
(2) Certified statement by Secretary/Assistant Secretary over corporate seal, certifying that the corporation is authorized to hold OCS leases.	XX	.....	.....	.....	
(3) Evidence of authority of titled positions to bind corporation, certified by Secretary/Assistant Secretary over corporate seal, including the following:	XX	.....	.....	.....	
(i) Certified copy of resolution of the board of directors with titles of officers authorized to bind corporation.					
(ii) Certified copy of resolutions granting corporate officer authority to issue a power of attorney.					
(iii) Certified copy of power of attorney or certified copy of resolution granting power of attorney.					
(4) Original certificate or certified copy of partnership or organization paperwork registering with the appropriate State official.	.....	XX	XX	XX	
(5) Copy of articles of partnership or organization evidencing filing with appropriate Secretary of State, certified by Secretary/Assistant Secretary of partnership or member or manager of LLC.	.....	XX	XX	XX	
(6) Original certificate or certified copy evidencing State where partnership or LLC is registered. Statement of authority to hold OCS leases, certified by Secretary/Assistant Secretary, *OR* original paperwork registering with the appropriate State official.	.....	XX	XX	XX	
(7) Statements from each partner or LLC member indicating the following:	.....	XX	XX	XX	
(i) If a corporation or partnership, statement of State of organization and authorization to hold OCS leases, certified by Secretary/Assistant Secretary over corporate seal, if a corporation.					
(ii) If an individual, a statement of citizenship.					
(8) Statement from general partner, certified by Secretary/Assistant Secretary that:	.....	XX	.....	.....	
(i) Each individual limited partner is a U.S. citizen and;					
(ii) Each corporate limited partner or other entity is incorporated or formed and organized under the laws of a U.S. State or territory.					
(9) Evidence of authority to bind partnership or LLC, if not specified in partnership agreement, articles of organization, or LLC regulations, *i.e.,* certificates of authority from Secretary/Assistant Secretary reflecting authority of officers.	.....	XX	XX	XX	
(10) Listing of members of LLC certified by Secretary/Assistant Secretary or any member or manager of LLC.	.....	.....	.....	XX	
(11) Copy of trust agreement or document establishing the trust and all amendments, properly certified by the trustee with reference to where the original documents are filed.	.....	.....	.....	.....	XX
(12) Statement indicating the law under which the trust is established and that the trust is authorized to hold OCS leases or grants.	.....	.....	.....	.....	XX

(e) A local, State, or Federal executive entity must submit a written statement that:

(1) It is qualified to hold leases or grants under this part; and

(2) The person(s) acting on behalf of the entity is authorized to bind the entity when conducting business with us.

(f) BOEM may require you to submit additional information at any time considering your bid or request for a noncompetitive lease.

§ 585.108 When must I notify BOEM if an action has been filed alleging that I am insolvent or bankrupt?

You must notify BOEM within 3 business days after you learn of any action filed alleging that you are insolvent or bankrupt.

§ 585.109 When must I notify BOEM of mergers, name changes, or changes of business form?

You must notify BOEM in writing of any merger, name change, or change of business form. You must notify BOEM as soon as practicable following the merger, name change, or change in business form, but no later than 120 days after the earliest of either the effective date, or the date of filing the change or action with the Secretary of the State or other authorized official in the State of original registry.

§ 585.110 How do I submit plans, applications, reports, or notices required by this part?

(a) You must submit all plans, applications, reports, or notices required by this part to BOEM at the following address: Deputy Director, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

(b) Unless otherwise stated, you must submit one paper copy and one electronic copy of all plans, applications, reports, or notices required by this part.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57098, Sept. 22, 2015]

§ 585.111 When and how does BOEM charge me processing fees on a case-by-case basis?

(a) BOEM will charge a processing fee on a case-by-case basis under the procedures in this section with regard to any application or request under this part if we decide at any time that the preparation of a particular document or study is necessary for the application or request and it will have a unique processing cost, such as the preparation of an Environmental Assessment (EA) or Environmental Impact Statement (EIS).

(1) Processing costs will include contract oversight and efforts to review and approve documents prepared by contractors, whether the contractor is paid directly by the applicant or through BOEM.

(2) We may apply a standard overhead rate to direct processing costs.

(b) We will assess the ongoing processing fee for each individual application or request according to the following procedures:

(1) Before we process your application or request, we will give you a written estimate of the proposed fee based on reasonable processing costs.

(2) You may comment on the proposed fee.

(3) You may:

(i) Ask for our approval to perform, or to directly pay a contractor to perform, all or part of any document, study, or other activity according to standards we specify, thereby reducing our costs for processing your application or request; or

(ii) Ask to pay us to perform, or contract for, all or part of any document, study, or other activity.

(4) We will then give you the final estimate of the processing fee amount with payment terms and instructions after considering your comments and any BOEM-approved work you will do.

(i) If we encounter higher or lower processing costs than anticipated, we will re-estimate our reasonable processing costs following the procedures in paragraphs (b)(1) through (4) of this section, but we will not stop ongoing processing unless you do not pay in accordance with paragraph (b)(5) of this section.

(ii) Once processing is complete, we will refund to you the amount of money that we did not spend on processing costs.

(5)(i) Consistent with the payment and billing terms provided in the final estimate, we will periodically estimate what our reasonable processing costs will be for a specific period and will bill you for that period. Payment is due to us 30 days after you receive your bill. We will stop processing your document

if you do not pay the bill by the date payment is due.

(ii) If a periodic payment turns out to be more or less than our reasonable processing costs for the period, we will adjust the next billing accordingly or make a refund. Do not deduct any amount from a payment without our prior written approval.

(6) You must pay the entire fee before we will issue the final document or take final action on your application or request.

(7) You may appeal our estimated processing costs in accordance with the regulations in 43 CFR part 4. We will not process the document further until the appeal is resolved, unless you pay the fee under protest while the appeal is pending. If the appeal results in a decision changing the proposed fee, we will adjust the fee in accordance with paragraph (b)(5)(ii) of this section. If we adjust the fee downward, we will not pay interest.

§ 585.112 Definitions.

Terms used in this part have the meanings as defined in this section:

Affected local government means with respect to any activities proposed, conducted, or approved under this part, any locality—

(1) That is, or is proposed to be, the site of gathering, transmitting, or distributing electricity or other energy product, or is otherwise receiving, processing, refining, or transshipping product, or services derived from activities approved under this part;

(2) That is used, or is proposed to be used, as a support base for activities approved under this part; or

(3) In which there is a reasonable probability of significant effect on land or water uses from activities approved under this part.

Affected State means with respect to any activities proposed, conducted, or approved under this part, any coastal State—

(1) That is, or is proposed to be, the site of gathering, transmitting, or distributing energy or is otherwise receiving, processing, refining, or transshipping products, or services derived from activities approved under this part;

(2) That is used, or is scheduled to be used, as a support base for activities approved under this part; or

(3) In which there is a reasonable probability of significant effect on land or water uses from activities approved under this part.

Alternate Use refers to the energy- or marine-related use of an existing OCS facility for activities not otherwise authorized by this subchapter or other applicable law.

Alternate Use RUE means a right-of-use and easement issued for activities authorized under subpart J of this part.

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 (*i.e.*, which are 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).

Best available and safest technology means the best available and safest technologies that BOEM determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.

Best management practices mean practices recognized within their respective industry, or by Government, as one of the best for achieving the desired output while reducing undesirable outcomes.

BOEM means Bureau of Ocean Energy Management of the Department of the Interior.

Certified Verification Agent (CVA) means an individual or organization, experienced in the design, fabrication, and installation of offshore marine facilities or structures, who will conduct specified third-party reviews, inspections, and verifications in accordance with this part.

Coastline means the same as the term ''coast line'' in section 2 of the Submerged Lands Act (43 U.S.C. 1301(c)).

Commercial activities mean, for renewable energy leases and grants, all activities associated with the generation, storage, or transmission of electricity

or other energy product from a renewable energy project on the OCS, and for which such electricity or other energy product is intended for distribution, sale, or other commercial use, except for electricity or other energy product distributed or sold pursuant to technology-testing activities on a limited lease. This term also includes activities associated with all stages of development, including initial site characterization and assessment, facility construction, and project decommissioning.

Commercial lease means a lease issued under this part that specifies the terms and conditions under which a person can conduct commercial activities.

Commercial operations mean the generation of electricity or other energy product for commercial use, sale, or distribution on a commercial lease.

Decommissioning means removing BOEM-approved facilities and returning the site of the lease or grant to a condition that meets the requirements under subpart I of this part.

Director means the Director of the Bureau of Ocean Energy Management (BOEM), of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

Distance means the minimum great circle distance.

Eligible State means a coastal State having a coastline (measured from the nearest point) no more than 15 miles from the geographic center of a qualified project area.

Facility means an installation that is permanently or temporarily attached to the seabed of the OCS. Facilities include any structures; devices; appurtenances; gathering, transmission, and distribution cables; pipelines; and permanently moored vessels. Any group of OCS installations interconnected with walkways, or any group of installations that includes a central or primary installation with one or more satellite or secondary installations, is a single facility. BOEM may decide that the complexity of the installations justifies their classification as separate facilities.

Geographic center of a project means the centroid (geometric center point) of a qualified project area. The centroid represents the point that is the weighted average of coordinates of the same dimension within the mapping system, with the weights determined by the density function of the system. For example, in the case of a project area shaped as a rectangle or other parallelogram, the geographic center would be that point where lines between opposing corners intersect. The geographic center of a project could be outside the project area itself if that area is irregularly shaped.

Governor means the Governor of a State or the person or entity lawfully designated by or under State law to exercise the powers granted to a Governor.

Grant means a right-of-way, right-of-use and easement, or alternate use right-of-use and easement issued under the provisions of this part.

Human environment means the physical, social, and economic components, conditions, and factors that 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.

Income, unless clearly specified to the contrary, refers to the money received by the project owner or holder of the lease or grant issued under this part. The term does not mean that project receipts exceed project expenses.

Lease means an agreement authorizing the use of a designated portion of the OCS for activities allowed under this part. The term also means the area covered by that agreement, when the context requires.

Lessee means the holder of a lease, a BOEM-approved assignee, and, when describing the conduct required of parties engaged in activities on the lease, it also refers to the operator and all persons authorized by the holder of the lease or operator to conduct activities on the lease.

Limited lease means a lease issued under this part that specifies the terms and conditions under which a person may conduct activities on the OCS that support the production of energy, but do not result in the production of electricity or other energy product for sale, distribution, or other commercial use exceeding a limit specified in the lease.

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the productivity, state, condition, and quality of the marine ecosystem. These include 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.

Miles mean nautical miles, as opposed to statute miles.

Natural resources include, without limiting the generality thereof, renewable energy, oil, gas, and all other minerals (as defined in section 2(q) of the OCS Lands Act), and marine animal and marine plant life.

Operator means the individual, corporation, or association having control or management of activities on the lease or grant under this part. The operator may be a lessee, grant holder, or a contractor designated by the lessee or holder of a grant under this part.

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), whose subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means, in addition to a natural person, an association (including partnerships and joint ventures); a Federal agency; a State; a political subdivision of a State; a Native American Tribal government; or a private, public, or municipal corporation.

Project, for the purposes of defining the source of revenues to be shared, means a lease ROW, RUE, or Alternate Use RUE on which the activities authorized under this part are conducted on the OCS. The term ''project'' may be used elsewhere in this rule to refer to these same authorized activities, the facilities used to conduct these activities, or to the geographic area of the project, *i.e.*, the project area.

Project area means the geographic surface leased, or granted, for the purpose of a specific project. If OCS acreage is granted for a project under some form of agreement other than a lease (*i.e.*, a ROW, RUE, or Alternate Use RUE issued under this part), the Federal acreage granted would be considered the project area. To avoid distortions in the calculation of the geometric center of the project area, project easements issued under this part are not considered part of the qualified project's area.

Project easement means an easement to which, upon approval of your Construction and Operations Plan (COP) or General Activities Plan (GAP), you are entitled as part of the lease for the purpose of installing, gathering, transmission, and distribution cables, pipelines, and appurtenances on the OCS as necessary for the full enjoyment of the lease.

Renewable Energy means energy resources other than oil and gas and minerals as defined in 30 CFR part 580. Such resources include, but are not limited to, wind, solar, and ocean waves, tides, and current.

Revenues mean bonuses, rents, operating fees, and similar payments made in connection with a project or project area. It does not include administrative fees such as those assessed for cost recovery, civil penalties, and forfeiture of financial assurance.

Right-of-use and easement (RUE) grant means an easement issued by BOEM under this part that authorizes use of a designated portion of the OCS to support activities on a lease or other use authorization for renewable energy activities. The term also means the area covered by the authorization.

Right-of-way (ROW) grant means an authorization issued by BOEM under this part to use a portion of the OCS for the construction and use of a cable or pipeline for the purpose of gathering, transmitting, distributing, or otherwise transporting electricity or other energy product generated or produced from renewable energy, but does not constitute a project easement under this part. The term also means the area covered by the authorization.

Secretary means the Secretary of the Interior or an official authorized to act on the Secretary's behalf.

Significant archaeological resource means an archaeological resource that meets the criteria of significance for eligibility for listing in the National Register of Historic Places, as defined in 36 CFR 60.4 or its successor.

Site assessment activities mean those initial activities conducted to characterize a site on the OCS, such as resource assessment surveys (e.g., meteorological and oceanographic) or technology testing, involving the installation of bottom-founded facilities.

You and *your* means an applicant, lessee, the operator, or designated operator, ROW grant holder, RUE grant holder, or Alternate Use RUE grant holder under this part, or the designated agent of any of these, or the possessive of each, depending on the context. The terms *You* and *your* also include contractors and subcontractors of the entities specified in the preceding sentence.

We, *us*, and *our* refer to the Bureau of Ocean Energy Management of the Department of the Interior, or its possessive, depending on the context.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21621, Apr. 17, 2014]

§ 585.113 How will data and information obtained by BOEM under this part be disclosed to the public?

(a) BOEM will make data and information available in accordance with the requirements and subject to the limitations of the Freedom of Information Act (FOIA) (5 U.S.C. 552), the regulations contained in 43 CFR part 2 (Records and Testimony).

(b) BOEM will not release such data and information that we have determined is exempt from disclosure under exemption 4 of FOIA. We will review such data and information and objections of the submitter by the following schedule to determine whether release at that time will result in substantial competitive harm or disclosure of trade secrets.

If you have a . . .	Then BOEM will review data and information for possible release:
(1) Commercial lease	At the earlier of: (i) 3 years after the initiation of commercial generation or (ii) 3 years after the lease terminates.
(2) Limited lease	At 3 years after the lease terminates.
(3) ROW or RUE grant	At the earliest of: (i) 10 years after the approval of the grant; (ii) Grant termination; or (iii) 3 years after the completion of construction activities.

(c) After considering any objections from the submitter, if we determine that release of such data and information will result in:

(1) No substantial competitive harm or disclosure of trade secrets, then the data and information will be released.

(2) Substantial competitive harm or disclosure of trade secrets, then the data and information will not be released at that time but will be subject to further review every 3 years thereafter.

§ 585.114 Paperwork Reduction Act statements—information collection.

(a) The Office of Management and Budget (OMB) has approved the information collection requirements in 30 CFR part 585 under 44 U.S.C. 3501, *et seq.*, and assigned OMB Control Number 1010–0176. The table in paragraph (e) of this section lists the subpart in the rule requiring the information and its title, summarizes the reasons for collecting the information, and summarizes how BOEM uses the information.

(b) Respondents are primarily renewable energy applicants, lessees, ROW grant holders, RUE grant holders, Alternate Use RUE grant holders, and operators. The requirement to respond to the information collection in this part is mandated under subsection 8(p) of the OCS Lands Act. Some responses are also required to obtain or retain a benefit, or may be voluntary.

(c) The Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) requires us to inform the public that 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.

(d) Comments regarding any aspect of the collections of information under

this part, including suggestions for reducing the burden, should be sent to the Information Collection Clearance Officer, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166.

(e) BOEM is collecting this information for the reasons given in the following table:

30 CFR 585 subpart, title, and/or BOEM Form (OMB Control No.)	Reasons for collecting information and how used
(1) Subpart A—General Provisions	To inform BOEM of actions taken to comply with general operational requirements on the OCS. To ensure that operations on the OCS meet statutory and regulatory requirements, are safe and protect the environment, and result in diligent development on OCS leases.
(2) Subpart B—Issuance of OCS Renewable Energy Leases	To provide BOEM with information needed to determine when to use a competitive process for issuing a renewable energy lease, to identify auction formats and bidding systems and variables that we may use when that determination is affirmative, and to determine the terms under which we will issue renewable energy leases.
(3) Subpart C—ROW Grants and RUE Grants for Renewable Energy Activities.	To issue ROW grants and RUE grants for OCS renewable energy activities that are not associated with a BOEM-issued renewable energy lease.
(4) Subpart D—Lease and Grant Administration	To ensure compliance with regulations pertaining to a lease or grant; assignment and designation of operator; and suspension, renewal, termination, relinquishment, and cancellation of leases and grants.
(5) Subpart E—Payments and Financial Assurance Requirements.	To ensure that payments and financial assurance payments for renewable energy leases comply with subpart E.
(6) Subpart F—Plans and Information Requirements	To enable BOEM to comply with the National Environmental Policy Act (NEPA), the Coastal Zone Management Act (CZMA), and other Federal laws and to ensure the safety of the environment on the OCS.
(7) Subpart G—Facility Design, Fabrication, and Installation	To enable BOEM to review the final design, fabrication, and installation of facilities on a lease or grant to ensure that these facilities are designed, fabricated, and installed according to appropriate standards in compliance with BOEM regulations, and where applicable, the approved plan.
(8) Subpart H—Environmental and Safety Management, Inspections, and Facility Assessments.	To ensure that lease and grant operations are conducted in a manner that is safe and protects the environment. To ensure compliance with other Federal laws, these regulations, the lease or grant, and approved plans.
(9) Subpart I—Decommissioning	To determine that decommissioning activities comply with regulatory requirements and approvals. To ensure that site clearance and platform or pipeline removal are properly performed to protect marine life and the environment and do not conflict with other users of the OCS.
(10) Subpart J—RUEs for Energy and Marine-Related Activities Using Existing OCS Facilities.	To enable BOEM to review information regarding the design, installation, and operation of RUEs on the OCS, to ensure that RUE operations are safe and protect the human, marine, and coastal environment. To ensure compliance with other Federal laws, these regulations, the RUE grant, and, where applicable, the approved plan.

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57098, Sept. 22, 2015]

§ 585.115 Documents incorporated by reference.

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

(1) BOEM will publish, as a rule, any changes in the documents incorporated by reference in the FEDERAL REGISTER.

(2) BOEM may amend by rule the list of industry standards incorporated by reference of the document effective without prior opportunity for public comment when BOEM determines that the revisions to a document result in safety improvements or represent new industry standard technology and do not impose undue costs on the affected parties; and

(3) BOEM may make a rule, effective immediately, amending the list of industry standards incorporated by reference if it determines good cause exists for doing so under 5 U.S.C. 553.

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

(c) You may comply with a later edition of a specific document incorporated by reference, only if:

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

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

(d) You may inspect these documents at the Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, VA 20166, 703–787–1605; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*. You may obtain the documents from the publishing organizations at the addresses given in the following table:

For . . .	Write to . . .
API Recommended Practices	American Petroleum Institute, 1220 L Street, NW., Washington, DC 20005–4070. *http://www.api.org/publications/*

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

Title of documents	Incorporated by reference at . . .
API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design; Twenty-first Edition, December 2000; Errata and Supplement 1, December 2002; Errata and Supplement 2, September 2005; Errata and Supplement 3, October 2007; Product No. G2AWSD.	30 CFR 585.825

[76 FR 64623, Oct. 18, 2011, as amended at 80 FR 57098, Sept. 22, 2015]

§ 585.116 Requests for information on the state of the offshore renewable energy industry.

(a) The Director may, from time to time, and at his discretion, solicit information from industry and other relevant stakeholders (including State and local agencies), as necessary, to evaluate the state of the offshore renewable energy industry, including the identification of potential challenges or obstacles to its continued development. Such requests for information may relate to the identification of environmental, technical, regulatory, or economic matters that promote or detract from continued development of renewable energy technologies on the OCS. From the information received, the Director may evaluate potential refinements to the OCS Alternative Energy Program that promote development of the industry in a safe and environmentally responsible manner, and that ensure fair value for use of the Nation's OCS.

(b) BOEM may make such requests for information on a regional basis, and may tailor the requests to specific types of renewable energy technologies.

(c) BOEM will publish such requests for information by the Director in the FEDERAL REGISTER.

§ 585.117 [Reserved]

§ 585.118 What are my appeal rights?

(a) Any party adversely affected by a BOEM official's final decision or order issued under the regulations of this part may appeal that decision or order to the Interior Board of Land Appeals. The appeal must conform with the procedures found in 30 CFR part 590 and 43 CFR part 4, subpart E. Appeal of a final decision for bid acceptance is covered under paragraph (c) of this section.

(b) A decision will remain in full force and effect during the period in which an appeal may be filed and during an appeal, unless a stay is granted pursuant to 43 CFR part 4.

(c) Our decision on a bid is the final action of the Department, except that an unsuccessful bidder may apply for reconsideration by the Director.

(1) A bidder whose bid we reject may file a written request for reconsideration with the Director within 15 days of the date of the receipt of the notice of rejection, accompanied by a statement of reasons, with one copy to us. The Director will respond in writing either affirming or reversing the decision.

(2) The delegation of review authority given to the Office of Hearings and Appeals does not apply to decisions on high bids for leases or grants under this part.

Subpart B—Issuance of OCS Renewable Energy Leases

GENERAL LEASE INFORMATION

§ 585.200 What rights are granted with a lease issued under this part?

(a) A lease issued under this part grants the lessee the right, subject to obtaining the necessary approvals, including but not limited to those required under the FERC hydrokinetic licensing process, and complying with all provisions of this part, to occupy, and install and operate facilities on, a designated portion of the OCS for the purpose of conducting:

(1) Commercial activities; or

(2) Other limited activities that support, result from, or relate to the production of energy from a renewable energy source.

(b) A lease issued under this part confers on the lessee the right to one or more project easements without further competition for the purpose of installing gathering, transmission, and distribution cables; pipelines; and appurtenances on the OCS as necessary for the full enjoyment of the lease.

(1) You must apply for the project easement as part of your COP or GAP, as provided under subpart F of this part; and

(2) BOEM will incorporate your approved project easement in your lease as an addendum.

(c) A commercial lease issued under this part may be developed in phases, with BOEM approval as provided in § 585.629.

§ 585.201 How will BOEM issue leases?

BOEM will issue leases on a competitive basis, as provided under §§ 585.210 through 585.225. However, if we determine after public notice of a proposed lease that there is no competitive interest, we will issue leases noncompetitively, as provided under §§ 585.230 and 585.232. We will issue leases on forms approved by BOEM and will include terms, conditions, and stipulations identified and developed through the process set forth in §§ 585.211 and 585.231.

§ 585.202 What types of leases will BOEM issue?

BOEM may issue leases on the OCS for the assessment and production of renewable energy and may authorize a combination of specific activities. We may issue commercial leases or limited leases.

§ 585.203 With whom will BOEM consult before issuance of a lease?

For leases issued under this part, through either the competitive or noncompetitive process, BOEM, prior to issuing the lease, will coordinate and consult with relevant Federal agencies (including, in particular, those agencies involved in planning activities

that are undertaken to avoid or minimize conflicts among users and maximize the economic and ecological benefits of the OCS, including multifaceted spatial planning efforts), the Governor of any affected State, the executive of any affected local government, and any affected Indian Tribe, as directed by subsections 8(p)(4) and (7) of the OCS Lands Act or other relevant Federal laws. Federal statutes that require BOEM to consult with interested parties or Federal agencies or to respond to findings of those agencies, including the Endangered Species Act (ESA) and the Magnuson-Stevens Fishery Conservation and Management Act (MSA). BOEM also engages in consultation with state and tribal historic preservation officers pursuant to the National Historic Preservation Act (NHPA).

[79 FR 21621, Apr. 17, 2014]

§ 585.204 What areas are available for leasing consideration?

BOEM may offer any appropriately platted area of the OCS, as provided in § 585.205, for a renewable energy lease, except any area within the exterior boundaries of any unit of the National Park System, National Wildlife Refuge System, National Marine Sanctuary System, or any National Monument.

§ 585.205 How will leases be mapped?

BOEM will prepare leasing maps and official protraction diagrams of areas of the OCS. The areas included in each lease will be in accordance with the appropriate leasing map or official protraction diagram.

§ 585.206 What is the lease size?

(a) BOEM will determine the size for each lease based on the area required to accommodate the anticipated activities. The processes leading to both competitive and noncompetitive issuance of leases will provide public notice of the lease size adopted. We will delineate leases by using mapped OCS blocks or portions, or aggregations of blocks.

(b) The lease size includes the minimum area that will allow the lessee sufficient space to develop the project and manage activities in a manner that is consistent with the provisions of this part. The lease may include whole lease blocks or portions of a lease block.

§§ 585.207–585.209 [Reserved]

COMPETITIVE LEASE PROCESS

§ 585.210 How does BOEM initiate the competitive leasing process?

BOEM may publish in the FEDERAL REGISTER a public notice of Request for Interest to assess interest in leasing all or part of the OCS for activities authorized in this part. BOEM will consider information received in response to a Request for Interest to determine whether there is competitive interest for scheduling sales and issuing leases. We may prepare and issue a national, regional, or more specific schedule of lease sales pertaining to one or more types of renewable energy.

§ 585.211 What is the process for competitive issuance of leases?

BOEM will use auctions to award leases on a competitive basis. We will publish details of the process to be employed for each lease sale auction in the FEDERAL REGISTER. For each lease sale, we will publish a Proposed Sale Notice and a Final Sale Notice. Individual lease sales will include steps such as:

(a) *Call for Information and Nominations (Call).* BOEM will publish in the FEDERAL REGISTER Calls for Information and Nominations for leasing in specified areas. The comment period following issuance of a Call will be 45 days. In this document, we may:

(1) Request comments on areas which should receive special consideration and analysis;

(2) 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; and

(3) Suggest areas to be considered by the respondents for leasing.

(b) *Area Identification.* BOEM will identify areas for environmental analysis and consideration for leasing. We will do this in consultation with appropriate Federal agencies, States, local

governments, affected Indian Tribes, and other interested parties.

(1) We may consider for lease those areas nominated in response to the Call for Information and Nominations, together with other areas that BOEM determines are appropriate for leasing.

(2) We will evaluate the potential effect of leasing on the human, marine, and coastal environments, and develop measures to mitigate adverse impacts, including lease stipulations.

(3) We will consult to develop measures, including lease stipulations and conditions, to mitigate adverse impacts on the environment; and

(4) We may hold public hearings on the environmental analysis after appropriate notice.

(c) *Proposed Sale Notice*. BOEM will publish the Proposed Sale Notice in the FEDERAL REGISTER and send it to the Governor of any affected State, any Indian Tribe that might be affected, and the executive of any local government that might be affected. The comment period following issuance of a Proposed Sale Notice will be 60 days.

(d) *Final Sale Notice*. BOEM will publish the Final Sale Notice in the FEDERAL REGISTER at least 30 days before the date of the sale.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21621, Apr. 17, 2014]

§ 585.212 What is the process BOEM will follow if there is reason to believe that competitors have withdrawn before the Final Sale Notice is issued?

BOEM may decide to end the competitive process before the Final Sale Notice if we have reason to believe that competitors have withdrawn and competition no longer exists. We will issue a second public notice of Request for Interest and consider comments received to confirm that there is no competitive interest.

(a) If, after reviewing comments in response to the notice of Request for Interest, BOEM determines that there is no competitive interest in the lease area, and one party wishes to acquire a lease, we will discontinue the competitive process and will proceed with the noncompetitive process set forth in § 585.231(d) through (i) following receipt of the acquisition fee specified in § 585.502(a).

(b) If, after reviewing comments in response to the notice of Request for Interest, BOEM determines that competitive interest in the lease area continues to exist, we will continue with the competitive process set forth in §§ 585.211 through 585.225.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21621, Apr. 17, 2014]

§ 585.213 What must I submit in response to a Request for Interest or a Call for Information and Nominations?

If you are a potential lessee, when you respond to a Request for Interest or a Call, your response must include the following items:

(a) The area of interest for a possible lease.

(b) A general description of your objectives and the facilities that you would use to achieve those objectives.

(c) A general schedule of proposed activities, including those leading to commercial operations.

(d) Available and pertinent data and information concerning renewable energy and environmental conditions in the area of interest, including energy and resource data and information used to evaluate the area of interest. BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and as provided in § 585.113.

(e) Documentation showing that you are qualified to hold a lease, as specified in § 585.107.

(f) Any other information requested by BOEM in the FEDERAL REGISTER notice.

§ 585.214 What will BOEM do with information from the Requests for Information or Calls for Information and Nominations?

BOEM will use the information received in response to the Requests or Calls to:

(a) Identify the lease area;

(b) Develop options for the environmental analysis and leasing provisions (stipulations, payments, terms, and conditions); and

(c) Prepare appropriate documentation to satisfy applicable Federal requirements, such as NEPA, CZMA, the ESA, and the MMPA.

§ 585.215 What areas will BOEM offer in a lease sale?

BOEM will offer the areas for leasing determined through the process set forth in § 585.211 of this part. We will not accept nominations after the Call for Information and Nominations closes.

§ 585.216 What information will BOEM publish in the Proposed Sale Notice and Final Sale Notice?

For each competitive lease sale, BOEM will publish a Proposed Sale Notice and a Final Sale Notice in the FEDERAL REGISTER. In the Proposed Sale Notice, we will request public comment on the items listed in this section. We will consider all public comments received in developing the final lease sale terms and conditions. We will publish the final terms and conditions in the Final Sale Notice. The Proposed Sale Notice and Final Sale Notice will include, or describe the availability of, information pertaining to:

(a) The area available for leasing.

(b) Proposed and final lease provisions and conditions, including, but not limited to:

(1) Lease size;

(2) Lease term;

(3) Payment requirements;

(4) Performance requirements; and

(5) Site-specific lease stipulations.

(c) Auction details, including:

(1) Bidding procedures and systems;

(2) Minimum bid;

(3) Deposit amount;

(4) The place and time for filing bids and the place, date, and hour for opening bids;

(5) Lease award method; and

(6) Bidding or application instructions.

(d) The official BOEM lease form to be used or a reference to that form.

(e) Criteria BOEM will use to evaluate competing bids or applications and how the criteria will be used in decision-making for awarding a lease.

(f) Award procedures, including how and when BOEM will award leases and how BOEM will handle unsuccessful bids or applications.

(g) Procedures for appealing the lease issuance decision.

(h) Execution of the lease instrument.

§§ 585.217–585.219 [Reserved]

COMPETITIVE LEASE AWARD PROCESS

§ 585.220 What auction format may BOEM use in a lease sale?

(a) Except as provided in § 585.231, we will hold competitive auctions to award renewable energy leases and will use one of the following auction formats, as determined through the lease sale process and specified in the Proposed Sale Notice and in the Final Sale Notice:

Type of auction	Bid variable	Bidding process
(1) Sealed bidding	A cash bonus or an operating fee rate	One sealed bid per company per lease or packaged bidding unit.
(2) Ascending bidding	A cash bonus or an operating fee rate	Continuous bidding per lease.
(3) Two-stage bidding (combination of ascending and sealed bidding).	An operating fee rate in one, both, or neither stage and a cash bonus in one, both, or neither stage.	Ascending or sealed bidding until: (i) Only two bidders remain, or (ii) More than one bidder offers to pay the maximum bid amount. Stage-two sealed or ascending bidding commences at some predetermined time after the end of stage-one bidding.
(4) Multiple-factor bidding	Factors may include, but are not limited to: technical merit, timeliness, financing and economics, environmental considerations, public benefits, compatibility with State and local needs, cash bonus, rental rate, and an operating fee rate.	One proposal per company per lease or packaged bidding unit.

(b) You must submit your bid and a deposit as specified in §§ 585.500 and 585.501 to cover the bid for each lease area, according to the terms specified in the Final Sale Notice.

§ 585.221 What bidding systems may BOEM use for commercial leases and limited leases?

(a) For commercial leases, we will specify minimum bids in the Final Sale Notice and use one of the following bidding systems, as specified in the Proposed Sale Notice and in the Final Sale Notice:

Bid system	Bid variable
(1) Cash bonus with a constant fee rate (decimal)	Cash bonus.
(2) Constant operating fee rate with fixed cash bonus	A fee rate used in the formula found in § 585.506 to set the operating fee per year during the operations term of your lease.
(3) Sliding operating fee rate with a fixed cash bonus	A fee rate used in the formula in § 585.506 to set the operating fee for the first year of the operations term of your lease. The fee rate for subsequent years changes by a mathematical function we specify in the Final Sale Notice.
(4) Cash bonus *and* constant operating fee rate	Cash bonus and operating fee rate as stated in paragraph (2) of this section (two-stage auction format only).
(5) Cash bonus *and* sliding operating fee rate	Cash bonus and operating fee rate as stated in paragraph (3) of this section (two-stage auction format only).
(6) Multiple-factor combination of nonmonetary and monetary factors.	BOEM will identify bidding variables in the Final Sale Notice. Variables may include: (i) Nonmonetary (e.g., technical merit) factors and (ii) Monetary (e.g., cash bonus, rental rate, fee rate) factors.

(b) For limited leases, the bid variable will be a cash bonus, with a minimum bid as we specify in the Final Sale Notice.

§ 585.222 What does BOEM do with my bid?

(a) If sealed bidding is used:

(1) We open the sealed bids at the place, date, and hour specified in the Final Sale Notice for the sole purpose of publicly announcing and recording the bids. We do not accept or reject any bids at that time.

(2) We reserve the right to reject any and all high bids, including a bid for any proposal submitted under the multiple-factor bidding format, regardless of the amount offered or bidding system used. The reasons for the rejection of a winning bid may include, but are not necessarily limited to, insufficiency, illegality, anti-competitive behavior, administrative error, and the presence of unusual bidding patterns. We intend to accept or reject all high bids within 90 days, but we may extend that time if necessary.

(b) If we use ascending bidding, we may, in the Final Sale Notice, reserve the right to accept the winning bid solely based on its being the highest bid submitted by a qualified bidder (qualified to be an OCS lessee under § 585.107).

(c) If we use two-stage bidding and the auction concludes with

(i) An ascending bidding stage, the winning bid will be determined as stated in paragraph (b) of this section; or

(ii) A sealed bidding stage, the winning bid will be determined as stated in paragraph (a) of this section.

(d) If we use multiple-factor bidding, determination of the winning bid for any proposal submitted will be made by a panel composed of members selected by BOEM. The details of the process will be described in the Final Sale Notice.

(e) We will send a written notice of our decision to accept or reject bids to all bidders whose deposits we hold.

§ 585.223 What does BOEM do if there is a tie for the highest bid?

(a) Unless otherwise specified in the Final Sale Notice, except in the first stage of a two-stage bidding auction, if more than one bidder on a lease submits the same high bid amount, the winning bidder will be determined by a further round or stage of bidding as described in the Final Sale Notice.

(b) The winning bidder will be subject to final confirmation following determination of bid adequacy.

§ 585.224 What happens if BOEM accepts my bid?

If we accept your bid, we will send you a notice with three copies of the lease form.

(a) Within 10 business days after you receive the lease copies, you must:

(1) Execute the lease;

(2) File financial assurance as required under §§ 585.515 through 585.537; and

(3) Pay the balance of the bonus bid as specified in the lease sale notice.

(b) Within 45 days after you receive the lease copies, you must pay the first 12-months' rent as required in § 585.503.

(c) When you execute three copies of the lease and return the copies to us, we will execute the lease on behalf of the United States and send you one fully executed copy.

(d) You will forfeit your deposit if you do not execute and return the lease within 10 business days of receipt, or otherwise fail to comply with applicable regulations or terms of the Final Sale Notice.

(e) We may extend the 10 business day time period for executing and returning the lease if we determine the delay to be caused by events beyond your control.

(f) We reserve the right to withdraw an OCS area in which we have held a lease sale before you and BOEM execute the lease in that area. If we exercise this right, we will refund your bid deposit, without interest.

(g) If the awarded lease is executed by an agent acting on behalf of the bidder, the bidder must submit, along with the executed lease, written evidence that the agent is authorized to act on behalf of the bidder.

(h) BOEM will consider the highest submitted qualified bid to be the winning bid when bidding occurs under the systems described in § 585.221(a)(1) through (5). We will determine the winning bid for proposals submitted under the multiple-factor bidding format on the basis of selection by the panel as specified in § 585.222(d) when the bidding system under § 585.221(a)(6) is used. We will refund the deposit on all other bids.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21621, Apr. 17, 2014]

§ 585.225 What happens if my bid is rejected, and what are my appeal rights?

(a) If we reject your bid, we will provide a written statement of the reasons and refund any money deposited with your bid, without interest.

(b) You may ask the BOEM Director for reconsideration, in writing, within 15 business days of bid rejection, under § 585.118(c)(1). We will send you a written response either affirming or reversing the rejection.

§§ 585.226–585.229 [Reserved]

NONCOMPETITIVE LEASE AWARD PROCESS

§ 585.230 May I request a lease if there is no Call?

You may submit an unsolicited request for a commercial lease or a limited lease under this part. Your unsolicited request must contain the following information:

(a) The area you are requesting for lease.

(b) A general description of your objectives and the facilities that you would use to achieve those objectives.

(c) A general schedule of proposed activities including those leading to commercial operations.

(d) Available and pertinent data and information concerning renewable energy and environmental conditions in the area of interest, including energy and resource data and information used to evaluate the area of interest. BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and as provided in § 585.113.

(e) If available from the appropriate State or local government authority, a statement that the proposed activity conforms with State and local energy planning requirements, initiatives, or guidance.

(f) Documentation showing that you meet the qualifications to become a lessee, as specified in § 585.107.

(g) An acquisition fee, as specified in § 585.502(a).

§ 585.231 How will BOEM process my unsolicited request for a noncompetitive lease?

(a) BOEM will consider unsolicited requests for a lease on a case-by-case basis and may issue a lease noncompetitively in accordance with this part. We will not consider an unsolicited request for a lease under this part that is proposed in an area of the OCS that is scheduled for a lease sale under this part.

(b) BOEM will issue a public notice of a request for interest relating to your proposal and consider comments received to determine if competitive interest exists.

(c) If BOEM determines that competitive interest exists in the lease area:

(1) BOEM will proceed with the competitive process set forth in §§ 585.210 through 585.225;

(2) If you submit a bid for the lease area in a competitive lease sale, your acquisition fee will be applied to the deposit for your bonus bid; and

(3) If you do not submit a bid for the lease area in a competitive lease sale, BOEM will not refund your acquisition fee.

(d) If BOEM determines that there is no competitive interest in a lease, we will publish in the FEDERAL REGISTER a notice of Determination of No Competitive Interest. After BOEM publishes this notice, you will be responsible for submitting any required consistency certification and necessary data and information pursuant to 15 CFR part 930, subpart D to the applicable State CZMA agency or agencies and BOEM.

(e) BOEM will coordinate and consult with affected Federal agencies, State, and local governments, and affected Indian tribes in the review of noncompetitive lease requests.

(f) After completing the review of your lease request, BOEM may offer you a noncompetitive lease.

(g) If you accept the terms and conditions of the lease, then we will issue the lease, and you must comply with all terms and conditions of your lease and all applicable provisions of this part. If we issue you a lease, we will send you a notice with 3 copies of the lease form.

(1) Within 10 business days after you receive the lease copies you must:

(i) Execute the lease;

(ii) File financial assurance as required under §§ 585.515 through 585.537; and

(2) Within 45 days after you receive the lease copies, you must pay the first 12-months' rent, as required in § 585.503.

(h) BOEM will publish in the FEDERAL REGISTER a notice announcing the issuance of your lease.

(i) If you do not accept the terms and conditions, BOEM will not issue a lease, and we will not refund your acquisition fee.

[76 FR 64623, Oct. 18, 2011, as amended at 77 FR 1019, Jan. 9, 2012; 79 FR 21622, Apr. 17, 2014]

§ 585.232 May I acquire a lease noncompetitively after responding to a Request for Interest or Call for Information and Nominations?

(a) If you submit an area of interest for a possible lease and BOEM receives no competing submissions in response to the RFI or Call, we may inform you that there does not appear to be competitive interest, and ask if you wish to proceed with acquiring a lease.

(b) If you wish to proceed with acquiring a lease, you must submit your acquisition fee as specified in § 585.502(a).

(c) After receiving the acquisition fee, BOEM will follow the process outlined in § 585.231(d) through (i).

[76 FR 64623, Oct. 18, 2011, as amended at 77 FR 1019, Jan. 9, 2012]

§§ 585.233–585.234 [Reserved]

COMMERCIAL AND LIMITED LEASE TERMS

§ 585.235 If I have a commercial lease, how long will my lease remain in effect?

(a) For commercial leases, the lease terms and applicable automatic extensions are as shown in the following table:

Lease term	Automatic extensions	Requirements
(1) Each commercial lease will have a preliminary term of 12 months, within which the lessee must submit: (i) a SAP; or (ii) a combined SAP and Construction and Operations Plan (COP). The preliminary term begins on the effective date of the lease.	If BOEM receives a SAP that satisfies the requirements of §§ 585.605 through 585.613 or a SAP/COP that satisfies the requirements of §§ 585.605 through 585.613 and §§ 585.620 through 585.629, the preliminary term will be extended for the time necessary for us to conduct technical and environmental reviews of the SAP or SAP/COP.	The SAP must meet the requirements of §§ 585.605 through 585.613. The SAP/COP must meet the requirements of §§ 585.605 through 585.613 and §§ 585.620 through 585.629.
(2) A commercial lease will have a site assessment term of five years to conduct site assessment activities and to submit a COP, if a SAP/COP has not been submitted. Your site assessment term begins when BOEM approves your SAP or SAP/COP.	If we receive a COP that satisfies the requirements of §§ 585.620 through 585.629, the site assessment term will be automatically extended for the period of time necessary for us to conduct technical and environmental reviews of the COP.	The COP must meet the requirements of §§ 585.620 through 585.629 of this part.
(3) A commercial lease will have an operations term of 25 years, unless a longer term is negotiated by the parties. A request for lease renewal must be submitted two years before the end of the operations term. If you submit a COP, your operations term begins on the date that BOEM approves the COP. If you submit a SAP/COP, your operations term begins on the earliest of the following dates: five years after BOEM approves the SAP/COP; when fabrication begins; or, when installation commences.	.....	The lease renewal request must meet the requirements in §§ 585.425 through 585.429.
(4) A commercial lease may have additional time added to the operations term through a lease renewal. The term of the lease renewal will not exceed the original term of the lease, unless a longer term is negotiated by the parties. The lease renewal term begins upon expiration of the original operations term.	.....	NOTE: BOEM may also order or grant a suspension of the operations term, as provided in §§ 585.415 through 585.421 thereby effectively extending the term of the lease.

(b) If you do not timely submit a SAP, COP, or SAP/COP, as appropriate, you may request additional time to extend the preliminary or site assessment term of your commercial lease that includes a revised schedule for submission of the plan, as appropriate.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21622, Apr. 17, 2014]

§ 585.236 If I have a limited lease, how long will my lease remain in effect?

(a) For limited leases, the lease terms are as shown in the following table:

Lease term	Extension or suspension	Requirements
(1) Each limited lease has a preliminary term of 12 months to submit a GAP. The preliminary term begins on the effective date of the lease.	If we receive a GAP that satisfies the requirements of §§ 585.640 through 585.648 of this part, the preliminary term will be automatically extended for the period of time necessary for us to conduct a technical and environmental review of the plans.	The GAP must meet the requirements of §§ 585.640 through 585.648.
(2) Each limited lease has an operations term of five years for conducting site assessment, technology testing, or other activities. The operations term begins on the date that we approve your GAP.	We may order or grant a suspension of the operations term as provided in §§ 585.415 through 585.421.	

(b) If you do not timely submit a GAP, you may request additional time to extend the preliminary term of your limited lease that includes a revised schedule for submission of a GAP.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21622, Apr. 17, 2014]

§ 585.237 What is the effective date of a lease?

(a) A lease issued under this part must be dated and becomes effective as of the first day of the month following the date a lease is signed by the lessor.

(b) If the lessee submits a written request and BOEM approves, a lease may be dated and become effective the first day of the month in which it is signed by the lessor.

§ 585.238 Are there any other renewable energy research activities that will be allowed on the OCS?

(a) The Director may issue OCS leases, ROW grants, and RUE grants to a Federal agency or a State for renewable energy research activities that support the future production, transportation, or transmission of renewable energy.

(b) In issuing leases, ROW grants, and RUE grants to a Federal agency or a State on the OCS for renewable energy research activities under this provision, BOEM will coordinate and consult with other relevant Federal agencies, any other affected State(s), affected local government executives, and affected Indian Tribes.

(c) BOEM may issue leases, RUEs, and ROWs for research activities managed by a Federal agency or a State only in areas for which the Director has determined, after public notice and opportunity to comment, that no competitive interest exists.

(d) The Director and the head of the Federal agency or the Governor of a requesting State, or their authorized representatives, will negotiate the terms and conditions of such renewable energy leases, RUEs, or ROWs under this provision on a case-by-case basis. The framework for such negotiations, and standard terms and conditions of such leases, RUEs, or ROWs may be set forth in a memorandum of agreement (MOA) or other agreement between BOEM and a Federal agency or a State. The MOA must include the agreement of the head of the Federal agency or the Governor to assure that all subcontractors comply with these regulations, other applicable laws, and terms and conditions of such leases or grants.

(e) Any lease, RUE, or ROW that BOEM issues to a Federal agency or to a State that authorizes access to an area of the OCS for research activities managed by a Federal agency or a State must include:

(1) Requirements to comply with all applicable Federal laws; and

(2) Requirements to comply with these regulations, except as otherwise provided in the lease or grant.

(f) BOEM will issue a public notice of any lease, RUE, ROW issued to a Federal agency or to a State, or an approved MOA for such research activities.

(g) BOEM will not charge any fees for the purpose of ensuring a fair return for the use of such research areas on the OCS.

Subpart C—Rights-of-Way Grants and Rights-of-Use and Easement Grants for Renewable Energy Activities

ROW GRANTS AND RUE GRANTS

§ 585.300 What types of activities are authorized by ROW grants and RUE grants issued under this part?

(a) An ROW grant authorizes the holder to install on the OCS cables, pipelines, and associated facilities that involve the transportation or transmission of electricity or other energy product from renewable energy projects.

(b) An RUE grant authorizes the holder to construct and maintain facilities or other installations on the OCS that support the production, transportation, or transmission of electricity or other energy product from any renewable energy resource.

(c) You do not need an ROW grant or RUE grant for a project easement authorized under § 585.200(b) to serve your lease.

§ 585.301 What do ROW grants and RUE grants include?

(a) An ROW grant:

(1) Includes the full length of the corridor on which a cable, pipeline, or associated facility is located;

(2) Is 200 feet (61 meters) in width, centered on the cable or pipeline, unless safety and environmental factors during construction and maintenance of the associated cable or pipeline require a greater width; and

(3) For the associated facility, is limited to the area reasonably necessary for a power or pumping station or other accessory facility.

(b) An RUE grant includes the site on which a facility or other structure is located and the areal extent of anchors, chains, and other equipment associated with a facility or other structure. The specific boundaries of an RUE will be determined by BOEM on a case-by-case basis and set forth in each RUE grant.

§ 585.302 What are the general requirements for ROW grant and RUE grant holders?

(a) To acquire an ROW grant or RUE grant you must provide evidence that you meet the qualifications as required in § 585.107.

(b) An ROW grant or RUE grant is subject to the following conditions:

(1) The rights granted will not prevent the granting of other rights by the United States, either before or after the granting of the ROW or RUE, provided that any subsequent authorization issued by BOEM in the area of a previously issued ROW grant or RUE grant may not unreasonably interfere with activities approved or impede existing operations under such a grant; and

(2) The holder agrees that the United States, its lessees, or other ROW grant or RUE grant holders may use or occupy any part of the ROW grant or RUE grant not actually occupied or necessarily incident to its use for any necessary activities.

§ 585.303 How long will my ROW grant or RUE grant remain in effect?

(a) Each ROW or RUE grant will have a preliminary term of 12 months from the date of issuance of the ROW or RUE grant within which to submit a GAP. The preliminary term begins on the effective date of the grant. You must submit a GAP no later than the end of the preliminary term for your grant to remain in effect. However, you may submit a GAP prior to the issuance of your ROW or RUE grant.

(b) Except as described in paragraph (a) of this section, your ROW grant or RUE grant will remain in effect for as long as the associated activities are properly maintained and used for the purpose for which the grant was made, unless otherwise expressly stated in the grant.

[79 FR 21623, Apr. 17, 2014]

§ 585.304 [Reserved]

OBTAINING ROW GRANTS AND RUE GRANTS

§ 585.305 How do I request an ROW grant or RUE grant?

You must submit to BOEM one paper copy and one electronic copy of a request for a new or modified ROW grant or RUE grant. You must submit a separate request for each ROW grant or RUE grant you are requesting. The request must contain the following information:

(a) The area you are requesting for a ROW grant or RUE grant.

(b) A general description of your objectives and the facilities that you would use to achieve those objectives.

(c) A general schedule of proposed activities.

(d) Pertinent information concerning environmental conditions in the area of interest.

§ 585.306 What action will BOEM take on my request?

BOEM will consider requests for ROW grants and RUE grants on a case-by-case basis and may issue a grant competitively, as provided in § 585.308, or noncompetitively if we determine after public notice that there is no competitive interest. BOEM will coordinate and consult with relevant Federal agencies, with the Governor of any affected State, and the executive of any affected local government.

(a) In response to an unsolicited request for a ROW grant or RUE grant, the BOEM will first determine if there is competitive interest, as provided in § 585.307.

(b) If BOEM determines that there is no competitive interest in a ROW grant or RUE grant, we will publish a notice in the FEDERAL REGISTER of such determination. After BOEM publishes this notice, you will be responsible for submitting any required consistency certification and necessary data and information pursuant to 15 CFR part 930, subpart D to the applicable State CZMA agency or agencies and BOEM. We will establish terms and conditions for the grant in consultation with you.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21623, Apr. 17, 2014]

§ 585.307 How will BOEM determine whether competitive interest exists for ROW grants and RUE grants?

To determine whether or not there is competitive interest:

(a) We will publish a public notice, describing the parameters of the project, to give affected and interested parties an opportunity to comment on the proposed ROW grant or RUE grant area.

(b) We will evaluate any comments received on the notice and make a determination of the level of competitive interest.

§ 585.308 How will BOEM conduct an auction for ROW grants and RUE grants?

(a) If BOEM determines that there is competitive interest, we will:

(1) Publish a notice of each grant auction in the FEDERAL REGISTER describing auction procedures, allowing interested persons 30 days to comment; and

(2) Conduct a competitive auction for issuing the ROW grant or RUE grant. The auction process for ROW grants and RUE grants will be conducted following the same process for leases set forth in §§ 585.211 through 585.225.

(b) If you are the successful bidder in an auction, you must pay the first year's rent, as provided in § 585.316.

§ 585.309 When will BOEM issue a noncompetitive ROW grant or RUE grant?

After completing the review of your grant request, BOEM may offer you a noncompetitive grant.

(a) If you accept the terms and conditions of the grant, then we will issue the grant, and you must comply with all terms and conditions of your grant and all applicable provisions of this part.

(b) If you do not accept the terms and conditions, BOEM will not issue a grant.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21623, Apr. 17, 2014]

§ 585.310 What is the effective date of an ROW grant or RUE grant?

Your ROW grant or RUE grant becomes effective on the date established by BOEM on the ROW grant or RUE grant instrument.

§§ 585.311–585.314 [Reserved]

FINANCIAL REQUIREMENTS FOR ROW GRANTS AND RUE GRANTS

§ 585.315 What deposits are required for a competitive ROW grant or RUE grant?

(a) You must make a deposit, as required in § 585.501(a), regardless of whether the auction is a sealed-bid, oral, electronic, or other auction format. BOEM will specify in the sale notice the official to whom you must submit the payment, the time by which the official must receive the payment, and the forms of acceptable payment.

(b) If your high bid is rejected, we will provide a written statement of reasons.

(c) For all rejected bids, we will refund, without interest, any money deposited with your bid.

§ 585.316 What payments are required for ROW grants or RUE grants?

Before we issue the ROW grant or RUE grant, you must pay:

(a) Any balance on accepted high bids to BOEM, as provided in the sale notice.

(b) An annual rent for the first year of the grant, as specified in § 585.508.

Subpart D—Lease and Grant Administration

NONCOMPLIANCE AND CESSATION ORDERS

§ 585.400 What happens if I fail to comply with this part?

(a) BOEM may take appropriate corrective action under this part if you fail to comply with applicable provisions of Federal law, the regulations in this part, other applicable regulations, any order of the Director, the provisions of a lease or grant issued under this part, or the requirements of an approved plan or other approval under this part.

(b) BOEM may issue to you a notice of noncompliance if we determine that there has been a violation of the regulations in this part, any order of the Director, or any provision of your lease, grant or other approval issued under this part. When issuing a notice of noncompliance, BOEM will serve you at your last known address.

(c) A notice of noncompliance will tell you how you failed to comply with this part, any order of the Director, and/or the provisions of your lease, grant or other approval, and will specify what you must do to correct the noncompliance and the time limits within which you must act.

(d) Failure of a lessee, operator, or grant holder under this part to take the actions specified in a notice of noncompliance within the time limit specified provides the basis for BOEM to issue a cessation order as provided in § 585.401, and/or a cancellation of the lease or grant as provided in § 585.437.

(e) If BOEM determines that any incident of noncompliance poses an imminent threat of serious or irreparable damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance, BOEM may include with its notice of noncompliance an order directing you to take immediate remedial action to alleviate threats and to abate the violation and, when appropriate, a cessation order.

(f) The BOEM may assess civil penalties, as authorized by section 24 of the OCS Lands Act, if you fail to comply with any provision of this part or any term of a lease, grant, or order issued under the authority of this part, after notice of such failure and expiration of any reasonable period allowed for corrective action. Civil penalties will be determined and assessed in accordance with the procedures set forth in 30 CFR part 550, subpart N.

(g) You may be subject to criminal penalties as authorized by section 24 of the OCS Lands Act.

§ 585.401 When may BOEM issue a cessation order?

(a) BOEM may issue a cessation order during the term of your lease or grant when you fail to comply with an applicable law; regulation; order; or provision of a lease, grant, plan, or other BOEM approval under this part. Except as provided in § 585.400(e), BOEM will allow you a period of time to correct any noncompliance before issuing an order to cease activities.

(b) A cessation order will set forth what measures you are required to take, including reports you are required to prepare and submit to BOEM, to receive approval to resume activities on your lease or grant.

§ 585.402 What is the effect of a cessation order?

(a) Upon receiving a cessation order, you must cease all activities on your lease or grant, as specified in the order. BOEM may authorize certain activities during the period of the cessation order.

(b) A cessation order will last for the period specified in the order or as otherwise specified by BOEM. If BOEM determines that the circumstances giving rise to the cessation order cannot be resolved within a reasonable time period, the Secretary may initiate cancellation of your lease or grant, as provided in § 585.437.

(c) A cessation order does not extend the term of your lease or grant for the period you are prohibited from conducting activities.

(d) You must continue to make all required payments on your lease or grant during the period a cessation order is in effect.

§§ 585.403–585.404 [Reserved]

DESIGNATION OF OPERATOR

§ 585.405 How do I designate an operator?

(a) If you intend to designate an operator who is not the lessee or grant holder, you must identify the proposed operator in your SAP (under § 585.610(a)(3)), COP (under § 585.626(b)(2)), or GAP (under § 585.645(b)(3)), as applicable. If no operator is designated in a SAP, COP, or GAP, BOEM will deem the lessee or grant holder to be the operator.

(b) An operator must be designated in any SAP, COP, or GAP if there is more than one lessee or grant holder for any individual lease or grant.

(c) Once approved in your plan, the designated operator is authorized to act on your behalf and required to perform activities necessary to comply with the OCS Lands Act, the lease or grant, and the regulations in this part.

(d) You, or your designated operator, must immediately provide BOEM with a written notification of change of address of the lessee or operator.

(e) If there is a change in the designated operator, you must provide written notice to BOEM and identify the new designated operator within 72 hours on a form approved by BOEM. The lessee(s) or grantee(s) is the operator and responsible for compliance until BOEM approves designation of the new operator.

(f) Designation of an operator under any lease or grant issued under this part does not relieve the lessee or grant holder of its obligations under this part or its lease or grant.

(g) A designated operator performing activities on the lease must comply with all regulations governing those activities and may be held liable or penalized for any noncompliance during the time it was operator, notwithstanding its subsequent resignation.

§ 585.406 Who is responsible for fulfilling lease and grant obligations?

(a) When you are not the sole lessee or grantee, you and your co-lessee(s) or co-grantee(s) are jointly and severally responsible for fulfilling your obligations under the lease or grant and the provisions of this part, unless otherwise provided in these regulations.

(b) If your designated operator fails to fulfill any of your obligations under the lease or grant and this part, BOEM may require you or any or all of your co-lessees or co-grantees to fulfill those obligations or other operational obligations under the OCS Lands Act, the lease, grant, or the regulations.

(c) Whenever the regulations in this part require the lessee or grantee to conduct an activity in a prescribed manner, the lessee or grantee and operator (if one has been designated) are jointly and severally responsible for complying with the regulations.

§ 585.407 [Reserved]

LEASE OR GRANT ASSIGNMENT

§ 585.408 May I assign my lease or grant interest?

(a) You may assign all or part of your lease or grant interest, including record title, subject to BOEM approval under this subpart. Each instrument that creates or transfers an interest must describe the entire tract or describe by officially designated subdivisions the interest you propose to create or transfer.

(b) You may assign a lease or grant interest by submitting one paper copy and one electronic copy of an assignment application to BOEM. The assignment application must include:

(1) BOEM-assigned lease or grant number;

(2) A description of the geographic area or undivided interest you are assigning;

(3) The names of both the assignor and the assignee, if applicable;

(4) The names and telephone numbers of the contacts for both the assignor and the assignee;

(5) The names, titles, and signatures of the authorizing officials for both the assignor and the assignee;

(6) A statement that the assignee agrees to comply with and to be bound by the terms and conditions of the lease or grant;

(7) The qualifications of the assignee to hold a lease or grant under § 585.107; and

(8) A statement on how the assignee will comply with the financial assurance requirements of §§ 585.515 through 585.537. No assignment will be approved until the assignee provides the required financial assurance.

(c) If you submit an application to assign a lease or grant, you will continue to be responsible for payments that are or become due on the lease or grant until the date BOEM approves the assignment.

(d) The assignment takes effect on the date BOEM approves your application.

(e) You do not need to request an assignment for mergers, name changes, or changes of business form. You must notify BOEM of these events under § 585.109.

§ 585.409 How do I request approval of a lease or grant assignment?

(a) You must request approval of each assignment on a form approved by BOEM, and submit originals of each instrument that creates or transfers ownership of record title or certified copies thereof within 90 days after the last party executes the transfer agreement.

(b) Any assignee will be subject to all the terms and conditions of your original lease or grant, including the requirement to furnish financial assurance in the amount required in §§ 585.515 through 585.537.

(c) The assignee must submit proof of eligibility and other qualifications specified in § 585.107.

(d) Persons executing on behalf of the assignor and assignee must furnish evidence of authority to execute the assignment.

§ 585.410 How does an assignment affect the assignor's liability?

As assignor, you are liable for all obligations, monetary and nonmonetary, that accrued under your lease or grant before BOEM approves your assignment. Our approval of the assignment does not relieve you of these accrued obligations. BOEM may require you to bring the lease or grant into compliance to the extent the obligation accrued before the effective date of your assignment if your assignee or subsequent assignees fail to perform any obligation under the lease or grant.

§ 585.411 How does an assignment affect the assignee's liability?

(a) As assignee, you are liable for all lease or grant obligations that accrue after BOEM approves the assignment. As assignee, you must comply with all the terms and conditions of the lease or grant and all applicable regulations, remedy all existing environmental and operational problems on the lease or grant, and comply with all decommissioning requirements under subpart I of this part.

(b) Assignees are bound to comply with each term or condition of the lease or grant and the regulations in this subchapter. You are jointly and severally liable for the performance of all obligations under the lease or grant and under the regulations in this part with each prior and subsequent lessee who held an interest from the time the obligation accrued until it is satisfied, unless this part provides otherwise.

§§ 585.412–585.414 [Reserved]

LEASE OR GRANT SUSPENSION

§ 585.415 What is a lease or grant suspension?

(a) A suspension is an interruption of the term of your lease or grant that may occur:

(1) As approved by BOEM at your request, as provided in § 585.416; or

(2) As ordered by BOEM, as provided in § 585.417.

(b) A suspension extends the term of your lease or grant for the length of time the suspension is in effect.

(c) Activities may not be conducted on your lease or grant during the period of a suspension except as expressly authorized by BOEM under the terms of the suspension.

§ 585.416 How do I request a lease or grant suspension?

You must submit a written request to BOEM that includes the following information no later than 90 days prior to the expiration of your appropriate lease or grant term:

(a) The reasons you are requesting suspension of your lease or grant term,

and the length of additional time requested.

(b) An explanation of why the suspension is necessary in order to ensure full enjoyment of your lease or grant and why it is in the lessor's or grantor's interest to approve the suspension.

(c) If you do not timely submit a SAP, COP, or GAP, as required, you may request a suspension to extend the preliminary or site assessment term of your lease or grant that includes a revised schedule for submission of a SAP, COP, or GAP, as appropriate.

(d) Any other information BOEM may require.

§ 585.417 When may BOEM order a suspension?

(a) BOEM may order a suspension under the following circumstances:

(1) When necessary to comply with judicial decrees prohibiting some or all activities under your lease;

(2) When continued activities pose an imminent threat of serious or irreparable harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance; or

(3) When the suspension is necessary for reasons of National security or defense.

(b) If BOEM orders a suspension under paragraph (a)(2) of this section, and if you wish to resume activities, we may require you to conduct a site-specific study that evaluates the cause of the harm, the potential damage, and the available mitigation measures. Other requirements and actions may occur:

(1) You may be required to pay for the study;

(2) You must furnish one paper copy and one electronic copy of the study and results to us;

(3) We will make the results available to other interested parties and to the public; and

(4) We will use the results of the study and any other information that become available:

(i) To decide if the suspension order can be lifted; and

(ii) To determine any actions that you must take to mitigate or avoid any damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance.

§ 585.418 How will BOEM issue a suspension?

(a) BOEM will issue a suspension order orally or in writing.

(b) BOEM will send you a written suspension order as soon as practicable after issuing an oral suspension order.

(c) The written order will explain the reasons for its issuance and describe the effect of the suspension order on your lease or grant and any associated activities. BOEM may authorize certain activities during the period of the suspension, as set forth in the suspension order.

§ 585.419 What are my immediate responsibilities if I receive a suspension order?

You must comply with the terms of a suspension order upon receipt and take any action prescribed within the time set forth therein.

§ 585.420 What effect does a suspension order have on my payments?

(a) While BOEM evaluates your request for a suspension under § 585.416, you must continue to fulfill your payment obligation until the end of the original term of your lease or grant. If our evaluation goes beyond the end of the original term of your lease or grant, the term of your lease or grant will be extended for the period of time necessary for BOEM to complete its evaluation of your request, but you will not be required to make payments during the time of the extension.

(b) If BOEM approves your request for a suspension, as provided in § 585.416, we may suspend your payment obligation, as appropriate for the term that is suspended, depending on the reasons for the requested suspension.

(c) If BOEM orders a suspension, as provided in § 585.417, your payments, as appropriate for the term that is suspended, will be waived during the suspension period.

§ 585.421 How long will a suspension be in effect?

A suspension will be in effect for the period specified by BOEM.

(a) BOEM will not approve a suspension request pursuant to § 585.416 for a period longer than 2 years.

(b) If BOEM determines that the circumstances giving rise to a suspension ordered under § 585.417 cannot be resolved within 5 years, the Secretary may initiate cancellation of the lease or grant, as provided in § 585.437.

§§ 585.422–585.424 [Reserved]

LEASE OR GRANT RENEWAL

§ 585.425 May I obtain a renewal of my lease or grant before it terminates?

You may request renewal of the operations term of your lease or the original authorized term of your grant. BOEM, at its discretion, may approve a renewal request to conduct substantially similar activities as were originally authorized under the lease or grant. BOEM will not approve a renewal request that involves development of a type of renewable energy not originally authorized in the lease or grant. BOEM may revise or adjust payment terms of the original lease, as a condition of lease renewal.

§ 585.426 When must I submit my request for renewal?

(a) You must request a renewal from BOEM:

(1) No later than 180 days before the termination date of your limited lease or grant.

(2) No later than 2 years before the termination date of the operations term of your commercial lease.

(b) You must submit to BOEM all information we request pertaining to your lease or grant and your renewal request.

§ 585.427 How long is a renewal?

BOEM will set the term of a renewal at the time of renewal on a case-by-case basis.

(a) For commercial leases, a renewal term will not exceed the original operations term unless a longer term is negotiated by the applicable parties.

(b) For limited leases, a renewal term will not exceed the original operations term.

(c) For RUE and ROW grants, a renewal will continue for as long as the associated activities are conducted and facilities properly maintained and used for the purpose for which the grant was made, unless otherwise expressly stated.

§ 585.428 What effect does applying for a renewal have on my activities and payments?

If you timely request a renewal:

(a) You may continue to conduct activities approved under your lease or grant under the original terms and conditions for as long as your request is pending decision by BOEM.

(b) You may request a suspension of your lease or grant, as provided in § 585.416, while we consider your request.

(c) For the period BOEM considers your request for renewal, you must continue to make all payments in accordance with the original terms and conditions of your lease or grant.

§ 585.429 What criteria will BOEM consider in deciding whether to renew a lease or grant?

BOEM will consider the following criteria in deciding whether to renew a lease or grant:

(a) Design life of existing technology.

(b) Availability and feasibility of new technology.

(c) Environmental and safety record of the lessee or grantee.

(d) Operational and financial compliance record of the lessee or grantee.

(e) Competitive interest and fair return considerations.

(f) Effects of the lease or grant on generation capacity and reliability within the regional electrical distribution and transmission system.

§§ 585.430–585.431 [Reserved]

LEASE OR GRANT TERMINATION

§ 585.432 When does my lease or grant terminate?

Your lease or grant terminates on whichever of the following dates occurs first:

(a) The expiration of the applicable term of your lease or grant, unless your term is automatically extended under § 585.235 or § 585.236, a request for renewal of your lease or grant is pending a decision by BOEM, or your lease or grant is suspended or renewed as provided in this subpart;

(b) A cancellation, as set forth in § 585.437; or

(c) Relinquishment, as set forth in § 585.435.

§ 585.433 What must I do after my lease or grant terminates?

(a) After your lease or grant terminates, you must:

(1) Make all payments due, including any accrued rentals and deferred bonuses; and

(2) Perform any other outstanding obligations under the lease or grant within 6 months.

(b) Within 2 years following termination of a lease or grant, you must remove or dispose of all facilities, installations, and other devices permanently or temporarily attached to the seabed on the OCS in accordance with a plan or application approved by BOEM under subpart I of this part.

(c) If you fail to comply with your approved decommissioning plan or application:

(1) BOEM may call for the forfeiture of your financial assurance; and

(2) You remain liable for removal or disposal costs and responsible for accidents or damages that might result from such failure.

§ 585.434 [Reserved]

LEASE OR GRANT RELINQUISHMENT

§ 585.435 How can I relinquish a lease or a grant or parts of a lease or grant?

(a) You may surrender the lease or grant, or an officially designated subdivision thereof, by filing one paper copy and one electronic copy of a relinquishment application with BOEM. A relinquishment takes effect on the date we approve your application, subject to the continued obligation of the lessee and the surety to:

(1) Make all payments due on the lease or grant, including any accrued rent and deferred bonuses;

(2) Decommission all facilities on the lease or grant to be relinquished to the satisfaction of BOEM; and

(3) Perform any other outstanding obligations under the lease or grant.

(b) Your relinquishment application must include:

(1) Name;

(2) Contact name;

(3) Telephone number;

(4) Fax number;

(5) E-mail address;

(6) BOEM-assigned lease or grant number, and, if applicable, the name of any facility;

(7) A description of the geographic area you are relinquishing;

(8) The name, title, and signature of your authorizing official (the name, title, and signature must match exactly the name, title, and signature in BOEM qualification records); and

(9) A statement that you will adhere to the requirements of subpart I of this part.

(c) If you have submitted an application to relinquish a lease or grant, you will be billed for any outstanding payments that are due before the relinquishment takes effect, as provided in paragraph (a) of this section.

LEASE OR GRANT CONTRACTION

§ 585.436 Can BOEM require lease or grant contraction?

At an interval no more frequent than every 5 years, the BOEM may review your lease or grant area to determine whether the lease or grant area is larger than needed to develop the project and manage activities in a manner that is consistent with the provisions of this part. BOEM will notify you of our proposal to contract the lease or grant area.

(a) BOEM will give you the opportunity to present orally or in writing information demonstrating that you need the area in question to manage lease or grant activities consistent with these regulations.

(b) Prior to taking action to contract the lease or grant area, BOEM will issue a decision addressing your contentions that the area is needed.

(c) You may appeal this decision under § 585.118 of this part.

LEASE OR GRANT CANCELLATION

§ 585.437 When can my lease or grant be canceled?

(a) The Secretary will cancel any lease or grant issued under this part upon proof that it was obtained by fraud or misrepresentation, and after notice and opportunity to be heard has been afforded to the lessee or grant holder.

(b) The Secretary may cancel any lease or grant issued under this part when:

(1) The Secretary determines after notice and opportunity for a hearing that, with respect to the lease or grant that would be canceled, the lessee or grantee has failed to comply with any applicable provision of the OCS Lands Act or these regulations; any order of the Director; or any term, condition or stipulation contained in the lease or grant, and that the failure to comply continued 30 days (or other period BOEM specifies) after you receive notice from BOEM. The Secretary will mail a notice by registered or certified letter to the lessee or grantee at its record post office address;

(2) The Secretary determines after notice and opportunity for a hearing that you have terminated commercial operations under your COP, as provided in § 585.635, or other approved activities under your GAP, as provided in § 585.656;

(3) Required by National security or defense; or

(4) The Secretary determines after notice and opportunity for a hearing that continued activity under the lease or grant:

(i) Would cause serious harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance; and

(ii) That the threat of harm or damage would 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 the lease or grant in force.

Subpart E—Payments and Financial Assurance Requirements

PAYMENTS

§ 585.500 How do I make payments under this part?

(a) For acquisition fees or the initial 12-months' rent paid for the preliminary term of your lease, you must make your electronic payments through the *Fees for Services* page on the BOEM Web site at *http://www.boem.gov*, and you must include one copy of the *Pay.gov* confirmation receipt page with your unsolicited request.

(b) For all other required rent payments and for operating fee payments, you must make your payments as required in 30 CFR 1218.51.

(c) This table summarizes payments you must make for leases and grants, unless otherwise specified in the Final Sale Notice:

	Payment	Amount	Due date	Payment mechanism	Section reference
Initial payments for leases					
(1) If your lease is issued competitively,	Bid Deposit	As set in Final Sale Notice/depends on bid.	With bid	Pay.Gov	§ 585.501.
	Bonus Balance		Lease issuance	30 CFR 1218.51.	
(2) If your lease is issued non-competitively.	Acquisition Fee	$0.25 per acre, unless otherwise set by the Director.	With application	Pay.gov	§ 585.502.
(3) All leases	Initial Rent	$3 per acre per year.	45 days after lease issuance.	Pay.gov	§ 585.503.
Subsequent payments for leases and project easements					
(4) All leases	Subsequent Rent	$3 per acre per year.	Annually	30 CFR 1218.51	§§ 585.503 and 585.504.

	Payment	Amount	Due date	Payment mechanism	Section reference
(5) If you have a project easement.	Rent	Greater of $5 per acre per year or $450 per year.	When operations term for associated lease starts, then annually.	30 CFR 1218.51	§ 585.507.
(7) If your commercial lease is producing,	Operating Fee	Determined by the formula in § 585.506.	Annually	30 CFR 1218.51	§ 585.506.
Payments for ROW grants and RUE grants*					
(8) All ROW grants and RUE grants.	Initial Rent	$70 per statute mile, and the greater of $5 per acre per year or $450 per year.	Grant Issuance	Pay.gov	§ 585.508.
	Subsequent Rent		Annually or in 5-year batches.	30 CFR 1218.51.	

*There is no acquisition fee for ROW grants or RUE grants.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21623, Apr. 17, 2014]

§ 585.501 What deposits must I submit for a competitively issued lease, ROW grant, or RUE grant?

(a) For a competitive lease or grant that we offer through sealed bidding, you must submit a deposit of 20 percent of the total bid amount, unless some other amount is specified in the Final Sale Notice.

(b) For a competitive lease that we offer through ascending bidding, you must submit a deposit as established in the Final Sale Notice.

(c) You must pay any balances on accepted high bids in accordance with the Final Sale Notice, this part, and your lease or grant instrument.

(d) The deposit will be forfeited for any successful bidder who fails to execute the lease within the prescribed time, or otherwise does not comply with the regulations concerning acquisition of a lease or grant or stipulations in the Final Sale Notice.

§ 585.502 What initial payment requirements must I meet to obtain a noncompetitive lease, ROW grant, or RUE grant?

When requesting a noncompetitive lease, you must meet the initial payment (acquisition fee) requirements of this section, unless specified otherwise in your lease instrument. No initial payment is required when requesting noncompetitive ROW grants and RUE grants.

(a) If you request a noncompetitive lease, you must submit an acquisition fee of $0.25 per acre, unless otherwise set by the Director, as provided in § 585.500.

(b) If BOEM determines there is no competitive interest, we will then:

(1) Retain your acquisition fee if we issue you a lease; or

(2) Refund your acquisition fee, without interest, if we do not issue your requested lease.

(c) If we determine that there is a competitive interest in an area you requested, then we will proceed with a competitive lease sale process provided for in subpart B of this part, and we will:

(1) Apply your acquisition fee to the required deposit for your bid amount if you submit a bid;

(2) Apply your acquisition fee to your bonus bid if you acquire the lease; or

(3) Retain your acquisition fee if you do not bid for or acquire the lease.

§ 585.503 What are the rent and operating fee requirements for a commercial lease?

(a) The rent for a commercial lease is $3 per acre per year, unless otherwise established in the Final Sale Notice or lease.

(1) You must pay ONRR the initial 12-months' rent 45 days after you receive the lease copies from BOEM in

accordance with the requirements provided in § 585.500(a).

(2) You must pay ONRR, under the regulations at 30 CFR part 1218, rent at the beginning of each subsequent 1-year period in accordance with the regulations at 30 CFR 1218.51 for the entire lease area until the facility begins to generate commercially, as specified in § 585.506 or as otherwise specified in the Final Sale Notice or lease instrument:

(i) For leases issued competitively, the BOEM will specify in the Final Sale Notice and lease any adjustment to the rent fee to take effect during the operations term and prior to the commercial generation.

(ii) For leases issued noncompetitively, the BOEM will specify in the lease any adjustment to the rent fee to take effect during the operations term and prior to the commercial generation.

(3) You must pay ONRR, under the regulations at 30 CFR part 1218, the rent for a project easement in addition to the lease rent, as provided in § 585.507. You must commence rent payments for your project easement upon our approval of your COP or GAP.

(b) After your lease begins commercial generation of electricity or on the date specified by BOEM, you must pay operating fees in the amount specified in § 585.506:

(1) For leases issued competitively, BOEM will specify in the Final Sale Notice and lease the date when operating fees commence; and

(2) For leases issued noncompetitively, BOEM will specify in the lease the date when operating fee commences.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21623, Apr. 17, 2014]

§ 585.504 How are my payments affected if I develop my lease in phases?

If you develop your commercial lease in phases, as approved by us in your COP under § 585.629, you must pay ONRR, under the regulations at 30 CFR part 1218:

(a) Rent on the portion of the lease that is not authorized for commercial operations.

(b) Operating fees on the portion of the lease that is authorized for commercial operations, in the amount specified in § 585.506 and as described in § 585.503(b).

(c) Rent for a project easement in addition to lease rent, as provided in § 585.507. You must commence rent payments for your project easement upon our approval of your COP.

§ 585.505 What are the rent and operating fee requirements for a limited lease?

(a) The rent for a limited lease is $3 per acre per year, unless otherwise established in the Final Sale Notice and your lease instrument.

(b) You must pay ONRR the initial 12-months' rent 45 days after you receive the lease copies from BOEM in accordance with the requirements provided in § 585.500(a).

(c) You must pay ONRR, under the regulations at 30 CFR part 1218, rent at the beginning of each subsequent 1-year period on the entire lease area for the duration of your operations term in accordance with the regulations at 30 CFR 1218.51.

(d) BOEM will not charge an operating fee for the authorized sale of power from a limited lease.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21623, Apr. 17, 2014]

§ 585.506 What operating fees must I pay on a commercial lease?

If you are generating electricity, you must pay ONRR, under the regulations at 30 CFR part 1218, operating fees on your commercial lease when you begin commercial generation, as described in § 585.503.

(a) BOEM will determine the annual operating fee for activities relating to the generation of electricity on your lease based on the following formula,

$$F = M * H * c * P * r,$$

Where:

(1) F is the dollar amount of the annual operating fee;

(2) M is the nameplate capacity expressed in megawatts;

(3) H is the number of hours in a year, equal to 8,760, used to calculate an annual payment;

(4) c is the ''capacity factor'' representing the anticipated efficiency of the facility's operation expressed as a decimal between zero and one;

(5) P is a measure of the annual average wholesale electric power price expressed in dollars per megawatt hour, as provided in paragraph (c)(2) of this section; and

(6) r is the operating fee rate expressed as a decimal between zero and one.

(b) The annual operating fee formula relating to the value of annual electricity generation is restated as:

F (annual operating fee)	=	M (nameplate capacity)	*	H (hours per year)	*	c (capacity factor)	*	P (power price)	*	r (operating fee rate)

(c) BOEM will specify operating fee parameters in the Final Sale Notice for commercial leases issued competitively and in the lease for those issued noncompetitively.

(1) Unless BOEM specifies otherwise, in the operating fee rate, ''r'' is 0.02 for each year the operating fee applies when you begin commercial generation of electricity. We may apply a different fee rate for new projects (*i.e.*, a new generation based on new technology) after considering factors such as program objectives, state of the industry, project type, and project potential. Also, we may agree to reduce or waive the fee rate under § 585.510.

(2) The power price ''P,'' for each year when the operating fee applies, will be determined annually. The process by which the power price will be determined will be specified in the Final Sale Notice and/or in the lease. BOEM:

(i) Will use the most recent annual average wholesale power price in the State in which a project's transmission cables make landfall, as published by the DOE, Energy Information Administration (EIA), or other publicly available wholesale power price indices; and

(ii) May adjust the published average wholesale power price to reflect documented variations by State or within a region and recent market conditions.

(3) BOEM will select the capacity factor ''c'' based upon applicable analogs drawn from present and future domestic and foreign projects that operate in comparable conditions and on comparable scales.

(i) Upon the completion of the first year of commercial operations on the lease, BOEM may adjust the capacity factor as necessary (to accurately represent a comparison of actual production over a given period of time with the amount of power a facility would have produced if it had run at full capacity) in a subsequent year.

(ii) After the first adjustment, BOEM may adjust the capacity factor (to accurately represent a comparison of actual generation over a given period of time with the amount of power a facility would have generated if it had run at full capacity) no earlier than in 5-year intervals from the most recent year that BOEM adjusts the capacity factor.

(iii) The process by which BOEM will adjust the capacity factor, including any calculations (incorporating an average capacity factor reflecting actual operating experience), will be specified in the lease. The operator or lessee may request review and adjustment of the capacity factor under § 585.510.

(4) Ten days after the anniversary date of when you began to commercially generate electricity, you must submit to BOEM documentation of the gross annual generation of electricity produced by the generating facility on the lease. You must use the same information collection form as authorized by the EIA for this information.

(5) For the nameplate capacity ''M,'' BOEM will use the total installed capacity of the equipment you install, as specified in your approved COP.

(d) You must submit all operating fee payments to BOEM in accordance with the provisions under 30 CFR 1218.51.

(e) BOEM will establish the operating fee in the Final Sale Notice or in the lease on a case-by-case basis for:

(1) Activities that do not relate to the generation of electricity (e.g., hydrogen production), and

(2) Leases issued for hydrokinetic activities requiring a FERC license.

§ 585.507 What rent payments must I pay on a project easement?

(a) You must pay ONRR, under the regulations at 30 CFR part 1218, a rent fee for your project easement of $5 per acre, subject to a minimum of $450 per year, unless specified otherwise in the Final Sale Notice or lease:

(1) The size of the project easement area for a cable or a pipeline is the full length of the corridor and a width of 200 feet (61 meters), centered on the cable or pipeline; and

(2) The size of a project easement area for an accessory platform is limited to the aerial extent of anchor chains and other facilities and devices associated with the accessory.

(b) You must commence rent payments for your project easement upon our approval of your COP or GAP:

(1) You must make the first rent payment when the operations term begins, as provided in § 585.500;

(2) You must submit all subsequent rent payments in accordance with the regulations at 30 CFR 1218.51; and

(3) You must continue to pay annual rent for your project easement until your lease is terminated.

§ 585.508 What rent payments must I pay on ROW grants or RUE grants associated with renewable energy projects?

(a) For each ROW grant BOEM approves under subpart C of this part, you must pay ONRR, under the regulations at 30 CFR part 1218, an annual rent as follows, unless specified otherwise in the Final Sale Notice:

(1) A fee of $70 for each nautical mile or part of a nautical mile of the OCS that your ROW crosses; and

(2) An additional $5 per acre, subject to a minimum of $450 for use of the entire affected area, if you hold a ROW grant that includes a site outside the corridor of a 200-foot width (61 meters), centered on the cable or pipeline. The affected area includes the areal extent of anchor chains, risers, and other devices associated with a site outside the corridor.

(b) For each RUE grant BOEM approves under subpart C of this part, you must pay ONRR, under the regulations at 30 CFR part 1218, a rent of:

(1) $5 per acre per year; or

(2) A minimum of $450 per year.

(c) You must make the rent payments required by paragraphs (a) and (b) of this section on:

(1) An annual basis;

(2) For a 5-year period; or

(3) For multiples of 5 years.

(d) You must make the first annual rent payment upon approval of your ROW grant or RUE grant request, as provided in § 585.500, and all subsequent rent payments to ONRR in accordance with the regulations at 30 CFR 1218.51.

§ 585.509 Who is responsible for submitting lease or grant payments to BOEM?

(a) For each lease, ROW grant, or RUE grant issued under this part, you must identify one person who is responsible for all payments due and payable under the provisions of the lease or grant. The responsible person identified is designated as the payor, and you must document acceptance of such responsibilities, as provided in 30 CFR 1218.52.

(b) All payors must submit payments and maintain auditable records in accordance with guidance we issue or any applicable regulations in subchapter A of this chapter. In addition, the lessee or grant holder must also maintain such auditable records.

§ 585.510 May BOEM reduce or waive my lease or grant payments?

(a) BOEM Director may reduce or waive the rent or operating fee or components of the operating fee, such as the fee rate or capacity factor, when the Director determines that it is necessary to encourage continued or additional activities.

(b) When requesting a reduction or waiver, you must submit an application to us that includes all of the following:

(1) The number of the lease, ROW grant, or RUE grant involved;

(2) Name of each lessee or grant holder of record;

(3) Name of each operator;

(4) A demonstration that:

(i) Continued activities would be uneconomic without the requested reduction or waiver, or

(ii) A reduction or waiver is necessary to encourage additional activities; and

(5) Any other information required by the Director.

(c) No more than 6 years of your operations term will be subject to a full waiver of the operating fee.

§§ 585.511–585.514 [Reserved]

FINANCIAL ASSURANCE REQUIREMENTS FOR COMMERCIAL LEASES

§ 585.515 What financial assurance must I provide when I obtain my commercial lease?

(a) Before BOEM will issue your commercial lease or approve an assignment of an existing commercial lease, you (or, for an assignment, the proposed assignee) must guarantee compliance with all terms and conditions of the lease by providing either:

(1) A $100,000 minimum, lease-specific bond; or

(2) Another approved financial assurance instrument guaranteeing performance up to $100,000, as specified in §§ 585.526 through 585.529.

(b) You meet the financial assurance requirements under this subpart if your designated lease operator provides a $100,000 minimum, lease-specific bond or other approved financial assurance that guarantees compliance with all terms and conditions of the lease.

(1) The dollar amount of the minimum, lease-specific financial assurance in paragraphs (a)(1) and (b) of this section will be adjusted to reflect changes in the Consumer Price Index-All Urban Consumers (CPI–U) or a substantially equivalent index if the CPI–U is discontinued; and

(2) The first CPI–U-based adjustment can be made no earlier than the 5-year anniversary of the adoption of this rule. Subsequent CPI–U-based adjustments may be made every 5 years thereafter.

§ 585.516 What are the financial assurance requirements for each stage of my commercial lease?

(a) The basic financial assurance requirements for each stage of your commercial lease are as follows:

Before BOEM will . . .	You must provide . . .
(1) Issue a commercial lease or approve an assignment of an existing commercial lease.	A $100,000 minimum, lease-specific financial assurance.
(2) Approve your SAP	A supplemental bond or other financial assurance, in an amount determined by BOEM, if upon reviewing your SAP, BOEM determines that a supplemental bond is required in addition to your minimum lease-specific bond, due to the complexity, number, and location of any facilities involved in your site assessment activities.
(3) Approve your COP	A supplemental bond or other financial assurance, in an amount determined by BOEM based on the complexity, number, and location of all facilities involved in your planned activities and commercial operation. The supplemental financial assurance requirement is in addition to your lease-specific bond and, if applicable, the previous supplement associated with SAP approval.
(4) Allow you to install facilities approved in your COP	A decommissioning bond or other financial assurance, in an amount determined by BOEM based on anticipated decommissioning costs. BOEM will allow you to provide your financial assurance for decommissioning in accordance with the number of facilities installed or being installed. BOEM must approve the schedule for providing the appropriate financial assurance coverage.

(b) Each bond or other financial assurance must guarantee compliance with all terms and conditions of the lease. You may provide a new bond or increase the amount of your existing bond, to satisfy any additional financial assurance requirements.

(c) For hydrokinetic commercial leases, supplemental financial assurance may be required in an amount determined by BOEM before FERC issues a license.

§ 585.517 How will BOEM determine the amounts of the supplemental and decommissioning financial assurance requirements associated with commercial leases?

(a) BOEM will base the determination for the amounts of the SAP, COP, and decommissioning financial assurance requirements on estimates of the cost to meet all accrued lease obligations.

(b) We determine the amount of the supplemental and decommissioning financial assurance requirements on a case-by-case basis. The amount of the financial assurance must be no less than the amount required to meet all lease obligations, including:

(1) The projected amount of rent and other payments due the Government over the next 12 months;

(2) Any past due rent and other payments;

(3) Other monetary obligations; and

(4) The estimated cost of facility decommissioning, as required by subpart I of this part.

(c) If your cumulative potential obligations and liabilities increase or decrease, we may adjust the amount of supplemental or the decommissioning financial assurance.

(1) If we propose adjusting your financial assurance amount, we will notify you of the proposed adjustment and give you an opportunity to comment; and

(2) We may approve a reduced financial assurance amount if you request it and if the reduced amount that you request continues to be greater than the sum of:

(i) The projected amount of rent and other payments due the Government over the next 12 months;

(ii) Any past due rent and other payments;

(iii) Other monetary obligations; and

(iv) The estimated cost of facility decommissioning.

§§ 585.518–585.519 [Reserved]

FINANCIAL ASSURANCE FOR LIMITED LEASES, ROW GRANTS, AND RUE GRANTS

§ 585.520 What financial assurance must I provide when I obtain my limited lease, ROW grant, or RUE grant?

(a) Before BOEM will issue your limited lease, ROW grant, or RUE grant, you or a proposed assignee must guarantee compliance with all terms and conditions of the lease or grant by providing either:

(1) A $300,000 minimum, lease- or grant-specific bond; or

(2) Another approved financial assurance instrument of such minimum level as specified in §§ 585.526 through 585.529.

(b) You meet the financial assurance requirements under this subpart if your designated lease or grant operator provides a minimum limited lease-specific or grant-specific bond in an amount sufficient to guarantee compliance with all terms and conditions of the limited lease or grant.

(1) The dollar amount of the minimum, lease- or grant-specific financial assurance in paragraph (a)(1) of this section will be adjusted to reflect changes in the CPI–U or a substantially equivalent index if the CPI–U is discontinued; and

(2) The first CPI–U-based adjustment can be made no earlier than the 5-year anniversary of the adoption of this rule. Subsequent CPI–U-based adjustments may be made every 5 years thereafter.

§ 585.521 Do my financial assurance requirements change as activities progress on my limited lease or grant?

(a) BOEM may require you to increase the level of your financial assurance as activities progress on your limited lease or grant. We will base the determination for the amount of financial assurance requirements on our estimate of the cost to meet all accrued lease or grant obligations, including:

(1) The projected amount of rent and other payments due the Government over the next 12 months;

(2) Any past due rent and other payments;

(3) Other monetary obligations; and

(4) The estimated cost of facility decommissioning.

(b) You may satisfy the requirement for increased financial assurance levels for the limited lease or grant by increasing the amount of your existing bond or replacing your existing bond.

(c) BOEM will authorize you to establish a separate decommissioning bond or other financial assurance for your limited lease or grant.

(1) The separate decommissioning bond or other financial assurance instrument must meet the requirements specified in §§ 585.525 through 585.529.

(2) BOEM will allow you to provide your financial assurance for decommissioning in accordance with the number of facilities installed or being installed. BOEM must approve the schedule for providing the appropriate financial assurance coverage.

§§ 585.522–585.524 [Reserved]

REQUIREMENTS FOR FINANCIAL ASSURANCE INSTRUMENTS

§ 585.525 What general requirements must a financial assurance instrument meet?

(a) Any bond or other acceptable financial assurance instrument that you provide must:

(1) Be payable to BOEM upon demand; and

(2) Guarantee compliance of all lessees, grant holders, operators, and payors with all terms and conditions of the lease or grant, any subsequent approvals and authorizations, and all applicable regulations.

(b) All bonds and other forms of financial assurance must be on or in a form approved by BOEM. You may submit this on an approved form that you have reproduced or generated by use of a computer. If the document you submit omits any terms and conditions that are included on the BOEM-approved form, your bond is deemed to contain the omitted terms and conditions.

(c) Surety bonds must be issued by an approved surety listed in the current Treasury Circular 570, as required by 31 CFR 223.16. You may obtain a copy of Circular 570 from the Treasury Web site at *http://www.fms.treas.gov/c570/*.

(d) Your surety bond cannot exceed the underwriting limit listed in the current Treasury Circular 570, except as permitted therein.

(e) You and a qualified surety must execute your bond. When the surety is a corporation, an authorized corporate officer must sign the bond and attest to it over the corporate seal.

(f) You may not terminate the period of liability of your bond or cancel your bond, except as provided in this subpart. Bonds must continue in full force and effect even though an event has occurred that could diminish or terminate a surety's obligation under State law.

(g) Your surety must notify you and BOEM within 5 business days after:

(1) It initiates any judicial or administrative proceeding alleging its insolvency or bankruptcy; or

(2) The Treasury decertifies the surety.

§ 585.526 What instruments other than a surety bond may I use to meet the financial assurance requirement?

(a) You may use other types of security instruments, if BOEM determines that such security protects BOEM to the same extent as the surety bond. BOEM will consider pledges of the following:

(1) U.S. Department of Treasury securities identified in 31 CFR part 225;

(2) Cash in an amount equal to the required dollar amount of the financial assurance, to be deposited and maintained in a Federal depository account of the U.S. Treasury by BOEM;

(3) Certificates of deposit or savings accounts in a bank or financial institution organized or authorized to transact business in the United States with:

(i) Minimum net assets of $500,000,000; and

(ii) Minimum Bankrate.com Safe & Sound rating of 3 Stars, and Capitalization, Assets, Equity and Liquidity (CAEL) rating of 3 or less;

(4) Negotiable U.S. Government, State, and municipal securities or bonds having a market value of not less than the required dollar amount of the financial assurance and maintained in a Securities Investors Protection

Corporation insured trust account by a licensed securities brokerage firm for the benefit of the BOEM;

(5) Investment-grade rated securities having a Standard and Poor's rating of AAA or an equivalent rating from a nationally recognized securities rating service having a market value of not less than the required dollar amount of the financial assurance and maintained in a Securities Investors Protection Corporation insured trust account by a licensed securities brokerage firm for the benefit of BOEM; and

(6) Insurance, if its form and function is such that the funding or enforceable pledges of funding are used to guarantee performance of regulatory obligations in the event of default on such obligations by the lessee. Insurance must have an A.M. Best rating of ''superior'' or an equivalent rating from a nationally recognized insurance rating service.

(b) If you use a Treasury security:

(1) You must post 115 percent of your financial assurance amount;

(2) You must monitor the collateral value of your security. If the collateral value of your security as determined in accordance with the 31 CFR part 203 Collateral Margins Table (which can be found at *http://www.treasurydirect.gov*) falls below the required level of coverage, you must pledge additional security to provide 115 percent of the required amount; and

(3) You must include with your pledge authority for us to sell the security and use the proceeds if we determine that you have failed to comply with any of the terms and conditions of your lease or grant, any subsequent approval or authorization, or applicable regulations.

(c) If you use the instruments described in paragraphs (a)(4) or (a)(5) of this section, you must provide BOEM by the end of each calendar year a certified statement describing the nature and market value of the instruments maintained in that account, and including any current statements or reports furnished by the brokerage firm to the lessee concerning the asset value of the account.

§ 585.527 May I demonstrate financial strength and reliability to meet the financial assurance requirement for lease or grant activities?

BOEM may allow you to use your financial strength and reliability to meet financial assurance requirements. We will make this determination based on audited financial statements, business stability, reliability, and compliance with regulations.

(a) You must provide the following information if you want to demonstrate financial strength and reliability to meet your financial assurance requirements:

(1) Audited financial statements (including auditor's certificate, balance sheet, and profit and loss sheet) that show you have financial capacity substantially in excess of existing and anticipated lease and other obligations;

(2) Evidence that shows business stability based on 5 years of continuous operation and generation of renewable energy on the OCS or onshore;

(3) Evidence that shows reliability in meeting obligations based on credit ratings or trade references, including names and addresses of other lessees, contractors, and suppliers with whom you have dealt; and

(4) Evidence that shows a record of compliance with laws, regulations, and lease, ROW, or RUE terms.

(b) If we approve your request to use your financial strength and reliability to meet your financial assurance requirements, you must submit annual updates to the information required by paragraph (a) of this section. You must submit this information no later than March 31 of each year.

(c) If the annual updates to the information required by paragraph (a) of this section do not continue to demonstrate financial strength and reliability or BOEM has reason to believe that you are unable to meet the financial assurance requirements of this section, after notice and opportunity for a hearing, BOEM will terminate your ability to use financial strength and reliability for financial assurance and require you to provide another type of financial assurance. You must provide this new financial assurance instrument within 90 days after we terminate

your use of financial strength and reliability.

§ 585.528 May I use a third-party guaranty to meet the financial assurance requirement for lease or grant activities?

(a) You may use a third-party guaranty if the guarantor meets the criteria prescribed in paragraph (b) of this section and submits an agreement meeting the criteria prescribed in paragraph (c) of this section. The agreement must guarantee compliance with the obligations of all lessees and operators and grant holders.

(b) BOEM will consider the following factors in deciding whether to accept an agreement:

(1) The length of time that your guarantor has been in continuous operation as a business entity. You may exclude periods of interruption that are beyond the guarantor's control by demonstrating, to the satisfaction of the Director, that the interruptions do not affect the likelihood of your guarantor remaining in business during the SAP, COP, and decommissioning stages of activities covered by the indemnity agreement.

(2) Financial information available in the public record or submitted by your guarantor in sufficient detail to show us that your guarantor meets the criterion stated in paragraph (b)(4) of this section. Such detail includes:

(i) The current rating for your guarantor's most recent bond issuance by a generally recognized bond rating service such as Moody's Investor Service or Standard and Poor's Corporation;

(ii) Your guarantor's net worth, taking into account liabilities for compliance with all terms and conditions of your lease, regulations, and other guarantees;

(iii) Your guarantor's ratio of current assets to current liabilities, taking into account liabilities for compliance with all terms and conditions of your lease, regulations, and other guarantees; and

(iv) Your guarantor's unencumbered domestic fixed assets.

(3) If the information in paragraph (b)(2) of this section is not publicly available, your guarantor must submit the information in the following table, to be updated annually within 90 days of the end of the fiscal year (FY) or as otherwise prescribed.

Your guarantor must submit . . .	That . . .
(i) Financial statements for the most recently completed FY	Include a report by an independent certified public accountant containing the accountant's audit 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 statement for completed quarter in the current FY	Your guarantor's financial officer certifies to be correct.
(iii) Additional information related to bonds, if requested by the Director.	Your guarantor's financial officer certifies to be correct.

(4) Your guarantor's total outstanding and proposed guarantees must not exceed 25 percent of its unencumbered domestic net worth.

(c) Your guarantor must submit an agreement executed by the guarantor and all parties bound by the agreement. All parties are bound jointly and severally and must meet the qualifications set forth in § 585.107.

(1) When any party is a corporation, two corporate officers authorized to execute the guaranty agreement on behalf of the corporation must sign the agreement.

(2) When any party is a partnership, joint venture, or syndicate, the guaranty agreement must bind each party who has a beneficial interest in your guarantor and provide that, upon BOEM demand under your guaranty, each party is jointly and severally liable for compliance with all terms and conditions of your lease(s) or grant(s) covered by the agreement.

(3) When forfeiture of the guaranty is called for, the agreement must provide that your guarantor will either bring your lease(s) or grant(s) into compliance or provide, within 7 days, sufficient funds to permit BOEM to complete corrective action.

(4) The guaranty agreement must contain a confession of judgment, providing that, if we determine that you are, or your operator or operating rights owner is, in default, the guarantor must not challenge the determination and must remedy the default.

(5) If you fail, or your operator or operating rights owner fails, to comply with any law, term, or regulation, your guarantor must either take corrective action or provide, within 7 days or other agreed upon time period, sufficient funds for BOEM to complete corrective action. Such compliance must not reduce your guarantor's liability.

(6) If your guarantor wants to terminate the period of liability, your guarantor must notify you and us at least 90 days before the proposed termination date, obtain our approval for termination of all or a specified portion of the guarantee for liabilities arising after that date, and remain liable for all your work performed during the period the agreement is in effect.

(7) Each guaranty submitted pursuant to this section is deemed to contain all the above terms, even if they are not actually in the agreement.

(d) Before the termination of your guaranty, you must provide an acceptable replacement in the form of a bond or other security.

§ 585.529 Can I use a lease- or grant-specific decommissioning account to meet the financial assurance requirements related to decommissioning?

(a) In lieu of a surety bond, BOEM may authorize you to establish a lease-, ROW grant-, or RUE grant-specific decommissioning account in a federally-insured institution. The funds may not be withdrawn from the account without our written approval.

(1) The funds must be payable to BOEM and pledged to meet your lease or grant decommissioning and site clearance obligations; and

(2) You must fully fund the account within the time BOEM prescribes to cover all costs of decommissioning including site clearance. BOEM will estimate the cost of decommissioning, including site clearance.

(b) Any interest paid on the account will be treated as account funds unless we authorize in writing that any interest be paid to the depositor.

(c) We may allow you to pledge Treasury securities, payable to BOEM on demand, to satisfy your obligation to make payments into the account. Acceptable Treasury securities and their collateral value are determined in accordance with 31 CFR part 203, Collateral Margins Table (which can be found at *http://www.treasurydirect.gov*).

(d) We may require you to commit a specified stream of revenues as payment into the account so that the account will be fully funded, as prescribed in paragraph (a)(2) of this section. The commitment may include revenue from other operations.

CHANGES IN FINANCIAL ASSURANCE

§ 585.530 What must I do if my financial assurance lapses?

(a) If your surety is decertified by the Treasury, becomes bankrupt or insolvent, or if your surety's charter or license is suspended or revoked, or if any other approved financial assurance expires for any reason, you must:

(1) Inform BOEM within 3 business days about the financial assurance lapse; and

(2) Provide new financial assurance in the amount set by BOEM, as provided in this subpart.

(b) You must notify BOEM within 3 business days after you learn of any action filed alleging that you, your surety, or third-party guarantor, is insolvent or bankrupt.

§ 585.531 What happens if the value of my financial assurance is reduced?

If the value of your financial assurance is reduced below the required financial assurance amount because of a default or any other reason, you must provide additional financial assurance sufficient to meet the requirements of this subpart within 45 days or within a different period as specified by BOEM.

§ 585.532 What happens if my surety wants to terminate the period of liability of my bond?

(a) Terminating the period of liability of a bond ends the period during which surety liability continues to accrue. The surety continues to be responsible for obligations and liabilities

that accrued during the period of liability and before the date on which BOEM terminates the period of liability under paragraph (b) of this section. The liabilities that accrue during a period of liability include:

(1) Obligations that started to accrue before the beginning of the period of liability and have not been met; and

(2) Obligations that began accruing during the period of liability.

(b) Your surety must submit to BOEM its request to terminate the period of liability under its bond and notify you of that request. If you intend to continue activities, or have not met all obligations of your lease or grant, you must provide a replacement bond or alternative form of financial assurance of equivalent or greater value. BOEM will terminate that period of liability within 90 days after BOEM receives the request.

§ 585.533 How does my surety obtain cancellation of my bond?

(a) BOEM will release a bond or allow a surety to cancel a bond, and will relieve the surety from accrued obligations only if:

(1) BOEM determines that there are no outstanding obligations covered by the bond; or

(2) The following occurs:

(i) BOEM accepts a replacement bond or an alternative form of financial assurance in an amount equal to or greater than the bond to be cancelled to cover the terminated period of liability;

(ii) The surety issuing the new bond has expressly agreed to assume all outstanding liabilities under the original bond that accrued during the period of liability that was terminated; and

(iii) The surety issuing the new bond has agreed to assume that portion of the outstanding liabilities that accrued during the terminated period of liability that exceeds the coverage of the bond prescribed under §§ 585.515, 585.516, 585.520, or 585.521, and of which you were notified.

(b) When your lease or grant ends, your surety(ies) remain(s) responsible, and BOEM will retain any financial assurance as follows:

(1) The period of liability ends when you cease all operations and activities under the lease or grant, including decommissioning and site clearance;

(2) Your surety or collateral financial assurance will not be released until 7 years after the lease ends, or a longer period as necessary to complete any appeals or judicial litigation related to your bonded obligation, or for BOEM to determine that all of your obligations under the lease or grant have been satisfied; and

(3) BOEM will reduce the amount of your bond or return a portion of your financial assurance if we determine that we need less than the full amount of the bond or financial assurance to meet any possible future obligations.

§ 585.534 When may BOEM cancel my bond?

When your lease or grant ends, your surety(ies) remain(s) responsible, and BOEM will retain any pledged security as shown in the following table:

Bond	The period of liability ends . . .	Your bond will not be released until . . .
(a) Bonds for commercial leases submitted under § 585.515.	When BOEM determines that you have met all of your obligations under the lease.	Seven years after the lease ends, or a longer period as necessary to complete any appeals or judicial litigation related to your bond obligation. BOEM will reduce the amount of your bond or return a portion of your security if BOEM determines that you need less than the full amount of the bond to meet any possible future obligations.
(b) Supplemental or decommissioning bonds submitted under § 585.516.	When BOEM determines that you have met all your decommissioning, site clearance, and other obligations.	(1) Seven years after the lease ends, or a longer period as necessary to complete any appeals or judicial litigation related to your bond obligation. BOEM will reduce the amount of your bond or return a portion of your security if BOEM determines that you need less than the full amount of the bond to meet any possible future obligations; and

Bond	The period of liability ends . . .	Your bond will not be released until . . .
		(2) BOEM determines that the potential liability resulting from any undetected noncompliance is not greater than the amount of the lease base bond.
(c) Bonds submitted under §§ 585.520 and 585.521 for limited leases, ROW grants, or RUE grants.	When BOEM determines that you have met all of your obligations under the limited lease or grant.	Seven years after the limited lease, ROW, or RUE grant or a longer period as necessary to complete any appeals or judicial litigation related to your bond obligation. BOEM will reduce the amount of your bond or return a portion of your security if BOEM determines that you need less than the full amount of the bond to meet any possible future obligations.

§ 585.535 Why might BOEM call for forfeiture of my bond?

(a) BOEM may call for forfeiture of all or part of the bond, pledged security, or other form of guaranty if:

(1) After notice and demand for performance by BOEM, you refuse or fail, within the timeframe we prescribe, to comply with any term or condition of your lease or grant, other authorization or approval, or applicable regulations; or

(2) You default on one of the conditions under which we accepted your bond.

(b) We may pursue forfeiture without first making demands for performance against any co-lessee or holder of an interest in your ROW or RUE, or other person approved to perform obligations under your lease or grant.

§ 585.536 How will I be notified of a call for forfeiture?

(a) BOEM will notify you and your surety, including any provider of financial assurance, in writing of the call for forfeiture and provide the reasons for the forfeiture and the amount to be forfeited. We will base the amount upon an estimate of the total cost of corrective action to bring your lease or grant into compliance.

(b) We will advise you and your surety that you may avoid forfeiture if, within 10 business days:

(1) You agree to and demonstrate in writing to BOEM that you will bring your lease or grant into compliance within the timeframe we prescribe, and you do so; or

(2) Your surety agrees to and demonstrates that it will bring your lease or grant into compliance within the timeframe we prescribe, even if the cost of compliance exceeds the face amount of the bond.

§ 585.537 How will BOEM proceed once my bond or other security is forfeited?

(a) If BOEM determines that your bond or other security is forfeited, we will collect the forfeited amount and use the funds to bring your lease or grant(s) into compliance and correct any default.

(b) If the amount collected under your bond or other security is insufficient to pay the full cost of corrective action, BOEM may take or direct action to obtain full compliance and recover all costs in excess of the forfeited bond from you or any co-lessee or co-grantee.

(c) If the amount collected under your bond or other security exceeds the full cost of corrective action to bring your lease or grant(s) into compliance, we will return the excess funds to the party from whom the excess was collected.

§§ 585.538–585.539 [Reserved]

Revenue Sharing With States

§ 585.540 How will BOEM equitably distribute revenues to States?

(a) BOEM will distribute among the eligible coastal States 27 percent of the following revenues derived from qualified projects, where a qualified project and qualified project area is determined in § 585.541 and an eligible State is determined in § 585.542, with each term defined in § 585.112. Revenues subject to distribution to eligible States include all bonuses, acquisition fees,

rentals, and operating fees derived from the entire qualified project area and associated project easements not limited to revenues attributable to the portion of the project area within 3 miles of the seaward boundary of a coastal State. The revenues to be shared do not include administrative fees such as service fees and those assessed for civil penalties and forfeiture of bond or other surety obligations.

(b) The project area is the area included within a single lease or grant. For each qualified project, BOEM will determine and announce the project area and its geographic center at the time it grants or issues a lease, easement, or right-of-way on the OCS. If a qualified project lease or grant's boundaries change significantly due to actions pursuant to §§ 585.435 or 585.436, BOEM will re-evaluate the project area to determine whether the geographic center has changed. If it has, BOEM will re-determine State eligibility and shares accordingly.

(c) To determine each eligible State's share of the 27 percent of the revenues for a qualified project, BOEM will use the inverse distance formula, which apportions shares according to the relative proximity of the nearest point on the coastline of each eligible State to the geographic center of the qualified project area. If S_i is equal to the nearest distance from the geographic center of the project area to the i = 1, 2, * * * nth eligible State's coastline, then eligible State i would be entitled to the fraction F_i of the 27-percent aggregate revenue share due to all the eligible States according to the formula:

$F_i = (1/S_i) \div (\Sigma_{i=}1 * * *_n(1/S_i))$.

§ 585.541 What is a qualified project for revenue sharing purposes?

A qualified project for the purpose of revenue sharing with eligible coastal States is one authorized under subsection 8(p) of the OCS Lands Act, which includes acreage within the area extending 3 nautical miles seaward of State submerged lands. A qualified project is subject to revenue sharing with those States that are eligible for revenue sharing under § 585.542. The entire area within a lease or grant for the qualified project, excluding project easements, is considered the qualified project area.

§ 585.542 What makes a State eligible for payment of revenues?

A State is eligible for payment of revenues if any part of the State's coastline is located within 15 miles of the announced geographic center of the project area of a qualified project. A State is not eligible for revenue sharing if all parts of that State's coastline are more than 15 miles from the announced geographic center of the qualified project area. This is the case even if the qualified project area is located wholly or partially within an area extending 3 nautical miles seaward of the submerged lands of that State or if there are no States with a coastline less than 15 miles from the announced geographic center of the qualified project area.

§ 585.543 Example of how the inverse distance formula works.

(a) Assume that the geographic center of the project area lies 12 miles from the closest coastline point of State A and 4 miles from the closest coastline point of State B. BOEM will round dollar shares to the nearest whole dollar. The proportional share due each State would be calculated as follows:

(1) State A's share = $[(1/12) \div (1/12 + 1/4)] = 1/4$.

(2) State B's share = $[(1/4) \div (1/12 + 1/4)] = 3/4$.

(b) Therefore, State B would receive a share of revenues that is three times as large as that awarded to State A, based on the finding that State B's nearest coastline is one-third the distance to the geographic center of the qualified project area as compared to State A's nearest coastline. Eligible States share the 27 percent of the total revenues from the qualified project as mandated under the OCS Lands Act. Hence, if the qualified project generates $1,000,000 of Federal revenues in a given year, the Federal Government would distribute the States' 27-percent share as follows:

(1) State A's share = $270,000 × 1/4 = $67,500.

(2) State B's share = $270,000 × 3/4 = $202,500.

Subpart F—Plans and Information Requirements

§ 585.600 What plans and information must I submit to BOEM before I conduct activities on my lease or grant?

You must submit a SAP, COP, or GAP and receive BOEM approval as set forth in the following table:

Before you:	you must:
(a) conduct any site assessment activities on your commercial lease,	submit and obtain approval for your SAP according to §§ 585.605 through 585.613.
(b) conduct any activities pertaining to construction of facilities for commercial operations on your commercial lease,	submit and obtain approval for your COP, according to §§ 585.620 through 585.629.
(c) conduct any activities on your limited lease, ROW grant, or RUE grant in any OCS area,	submit and obtain approval for your GAP according to §§ 585.640 through 585.648.

§ 585.601 When am I required to submit my plans to BOEM?

You must submit your plans as follows:

(a) You may submit your SAP or GAP prior to lease or grant issuance, but must submit your SAP or your GAP no later than 12 months from the date of lease or grant issuance.

(b) If you intend to continue your commercial lease with an operations term, you must submit a COP, or a FERC license application, at least 6 months before the end of your site assessment term.

(c) You may submit your COP or FERC license application with your SAP.

(1) You must provide sufficient data and information with your COP for BOEM to complete the needed reviews and NEPA analysis; and

(2) BOEM may need to conduct additional reviews, including NEPA analysis, if significant new information becomes available after you complete your site assessment activities or you revise your COP. As a result of the additional reviews, we may require modification of your COP.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21623, Apr. 17, 2014]

§ 585.602 What records must I maintain?

Until BOEM releases your financial assurance under § 585.534, you must maintain and provide to BOEM, upon request, all data and information related to compliance with required terms and conditions of your SAP, COP, or GAP.

§§ 585.603–585.604 [Reserved]

SITE ASSESSMENT PLAN AND INFORMATION REQUIREMENTS FOR COMMERCIAL LEASES

§ 585.605 What is a Site Assessment Plan (SAP)?

(a) A SAP describes the activities (e.g., installation of meteorological towers, meteorological buoys) you plan to perform for the characterization of your commercial lease, including your project easement, or to test technology devices.

(1) Your SAP must describe how you will conduct your resource assessment (e.g., meteorological and oceanographic data collection) or technology testing activities; and

(2) BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and as provided in § 585.113.

(b) Your SAP must include data from:

(1) Physical characterization surveys (e.g., geological and geophysical surveys or hazards surveys); and

(2) Baseline environmental surveys (e.g., biological or archaeological surveys).

(c) You must receive BOEM approval of your SAP before you can begin any

of the approved activities on your lease, as provided in § 585.613.

(d) If you propose to construct a facility or combination of facilities deemed by BOEM to be complex or significant, as provided in § 585.613(a)(1), you must also comply with the requirements of subpart G of this part and submit your Safety Management System as required by § 585.810.

§ 585.606 What must I demonstrate in my SAP?

(a) Your SAP must demonstrate that you have planned and are prepared to conduct the proposed site assessment activities in a manner that conforms to your responsibilities listed in § 585.105(a) and:

(1) Conforms to all applicable laws, regulations, and lease provisions of your commercial lease;

(2) Is safe;

(3) Does not unreasonably interfere with other uses of the OCS, including those involved with National security or defense;

(4) Does not cause undue harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(5) Uses best available and safest technology;

(6) Uses best management practices; and

(7) Uses properly trained personnel.

(b) You must also demonstrate that your site assessment activities will collect the necessary information and data required for your COP, as provided in § 585.626(a).

§ 585.607 How do I submit my SAP?

You must submit one paper copy and one electronic version of your SAP to BOEM at the address listed in § 585.110(a).

§§ 585.608–585.609 [Reserved]

Contents of the Site Assessment Plan

§ 585.610 What must I include in my SAP?

Your SAP must include the following information, as applicable.

(a) For all activities you propose to conduct under your SAP, you must provide the following information:

Project information	Including
(1) Contact information	The name, address, e-mail address, and phone number of an authorized representative.
(2) The site assessment or technology testing concept	A discussion of the objectives; description of the proposed activities, including the technology you will use; and proposed schedule from start to completion.
(3) Designation of operator, if applicable	As provided in § 585.405.
(4) Commercial lease stipulations and compliance	A description of the measures you took, or will take, to satisfy the conditions of any lease stipulations related to your proposed activities.
(5) A location plat	The surface location and water depth for all proposed and existing structures, facilities, and appurtenances located both offshore and onshore.
(6) General structural and project design, fabrication, and installation.	Information for each type of facility associated with your project.
(7) Deployment activities	A description of the safety, prevention, and environmental protection features or measures that you will use.
(8) Your proposed measures for avoiding, minimizing, reducing, eliminating, and monitoring environmental impacts.	A description of the measures you will use to avoid or minimize adverse effects and any potential incidental take, before you conduct activities on your lease, and how you will mitigate environmental impacts from your proposed activities, including a description of the measures you will use as required by subpart H of this part.
(9) CVA nomination, if required	CVA nominations for reports in subpart G of this part, as required by § 585.706, or a request to waive the CVA requirement, as required by § 585.705(c).
(10) Reference information	A list of any document or published source that you cite as part of your plan. You may reference information and data discussed in other plans you previously submitted or that are otherwise readily available to BOEM.
(11) Decommissioning and site clearance procedures	A discussion of methodologies.
(12) Air quality information	Information as described in § 585.659 of this section.

Project information	Including
(13) A listing of all Federal, State, and local authorizations or approvals required to conduct site assessment activities on your lease.	A statement indicating whether such authorization or approval has been applied for or obtained.
(14) A list of agencies and persons with whom you have communicated, or with whom you will communicate, regarding potential impacts associated with your proposed activities.	Contact information and issues discussed.
(15) Financial assurance information	Statements attesting that the activities and facilities proposed in your SAP are or will be covered by an appropriate bond or other approved security, as required in §§ 585.515 and 585.516.
(16) Other information	Additional information as requested by BOEM.

(b) You must provide the results of geophysical and geological surveys, hazards surveys, archaeological surveys (if required), and baseline collection studies (e.g., biological) with the supporting data in your SAP:

Information	Report contents	Including
(1) Geotechnical	The results from the geotechnical survey with supporting data.	A description of all relevant seabed and engineering data and information to allow for the design of the foundation for that facility. You must provide data and information to depths below which the underlying conditions will not influence the integrity or performance of the structure. This could include a series of sampling locations (borings and in situ tests) as well as laboratory testing of soil samples, but may consist of a minimum of one deep boring with samples.
(2) Shallow hazards	The results from the shallow hazards survey with supporting data.	A description of information sufficient to determine the presence of the following features and their likely effects on your proposed facility, including: (i) Shallow faults; (ii) Gas seeps or shallow gas; (ii) Slump blocks or slump sediments; (iv) Hydrates; and (v) Ice scour of seabed sediments.
(3) Archaeological resources.	The results from the archaeological survey with supporting data, if required.	(i) A description of the results and data from the archaeological survey; (ii) A description of the historic and prehistoric archaeological resources, as required by the National Historic Preservation Act (NHPA) of 1966, as amended.
(4) Geological survey	The results from the geological survey with supporting data.	A report that describes the results of a geological survey that includes descriptions of: (i) Seismic activity at your proposed site; (ii) Fault zones; (iii) The possibility and effects of seabed subsidence; and (iv) The extent and geometry of faulting attenuation effects of geologic conditions near your site.
(5) Biological survey	The results from the biological survey with supporting data.	A description of the results of a biological survey, including descriptions of the presence of live bottoms; hard bottoms; topographic features; and surveys of other marine resources such as fish populations (including migratory populations), marine mammals, sea turtles, and sea birds.

(c) If you submit your COP or FERC license application with your SAP then:

(1) You must provide sufficient data and information with your COP or FERC license application for BOEM and/or FERC to complete the needed reviews and NEPA analysis.

(2) You may need to revise your COP or FERC license application and BOEM

and/or FERC may need to conduct additional reviews, including NEPA analysis, if new information becomes available after you complete your site assessment activities.

§ 585.611 What information and certifications must I submit with my SAP to assist BOEM in complying with NEPA and other relevant laws?

You must submit, with your SAP, detailed information to assist BOEM in complying with NEPA and other relevant laws as appropriate.

(a) A SAP submitted for an area in which BOEM has not previously reviewed site assessment activities under NEPA or other applicable Federal laws, must describe those resources, conditions, and activities listed in the following table that could be affected by your proposed activities or that could affect the activities proposed in your SAP.

(b) For a SAP submitted for an area in which BOEM has previously considered site assessment activities under applicable Federal law (e.g., a NEPA analysis and CZMA consistency determination for site assessment activities), BOEM will review the SAP to determine if its impacts are consistent with those previously considered. If the anticipated effects of your proposed SAP activities are significantly different than those previously anticipated, we may determine that additional NEPA and other relevant Federal reviews are required. In that case, BOEM will notify you of such determination, and you must submit a SAP that describes those resources, conditions, and activities listed in the following table that could be affected by your proposed activities or that could affect the activities proposed in your SAP, including:

Type of information:	Including:
(1) Hazard information	Meteorology, oceanography, sediment transport, geology, and shallow geological or manmade hazards.
(2) Water quality	Turbidity and total suspended solids from construction.
(3) Biological resources	Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, plankton, sea grasses, and other plant life.
(4) Threatened or endangered species.	As required by the Endangered Species Act (ESA) of 1973 (16 U.S.C. 1531 *et seq.*).
(5) Sensitive biological resources or habitats.	Essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, hard bottom habitat, chemosynthetic communities, calving grounds, barrier islands, beaches, dunes, and wetlands.
(6) Archaeological resources	As required by the NHPA (16 U.S.C. 470 *et seq.*), as amended.
(7) Social and economic conditions.	Employment, existing offshore and coastal infrastructure (including major sources of supplies, services, energy, and water), land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including typical fishing seasons, location, and type), minority and lower income groups, coastal zone management programs, and viewshed.
(8) Coastal and marine uses	Military activities, vessel traffic, and energy and nonenergy mineral exploration or development.
(9) Consistency Certification	If required by CZMA, as appropriate: (i) 15 CFR part 930, subpart D, if the SAP is submitted prior to lease issuance; (ii) 15 CFR part 930, subpart E, if the SAP is submitted after lease issuance.
(10) Other resources, conditions, and activities.	As identified by BOEM.

[79 FR 21623, Apr. 17, 2014]

§ 585.612 How will my SAP be processed for Federal consistency under the Coastal Zone Management Act?

Your SAP will be processed based on whether it is submitted before or after your lease is issued:

If your SAP is submitted:	Consistency review of your SAP will be handled as follows:
(a) Before lease issuance	You will furnish a copy of your SAP, consistency certification, and necessary data and information pursuant to 15 CFR part 930, subpart D, to the applicable State CZMA agency or agencies and BOEM at the same time.

If your SAP is submitted:	Consistency review of your SAP will be handled as follows:
(b) After lease issuance	You will submit a copy of your SAP, consistency certification, and necessary data and information pursuant to 15 CFR part 930, subpart E to BOEM. BOEM will forward to the applicable State CZMA agency or agencies one paper copy and one electronic copy of your SAP, consistency certification, and necessary data and information required under 15 CFR part 930, subpart E, after BOEM has determined that all information requirements for the SAP are met.

[79 FR 21624, Apr. 17, 2014]

§ 585.613 How will BOEM process my SAP?

(a) BOEM will review your submitted SAP, and additional information provided pursuant to § 585.611, to determine if it contains the information necessary to conduct our technical and environmental reviews.

(1) We will notify you if we deem your proposed facility or combination of facilities to be complex or significant;

(2) We will notify you if your submitted SAP lacks any necessary information;

(b) BOEM will prepare NEPA analysis, as appropriate.

(c) As appropriate, we will coordinate and consult with relevant Federal and State agencies, executives of relevant local governments, and affected Indian Tribes and will provide to other Federal, State, and local agencies and affected Indian Tribes relevant nonproprietary data and information pertaining to your proposed activities.

(d) During the review process, we may request additional information if we determine that the information provided is not sufficient to complete the review and approval process. If you fail to provide the requested information, BOEM may disapprove your SAP.

(e) Upon completion of our technical and environmental reviews and other reviews required by Federal laws (e.g., CZMA), BOEM may approve, disapprove, or approve with modifications your SAP.

(1) If we approve your SAP, we will specify terms and conditions to be incorporated into your SAP. You must certify compliance with those terms and conditions required under § 585.615(c); and

(2) If we disapprove your SAP, we will inform you of the reasons and allow you an opportunity to submit a revised plan making the necessary corrections, and may suspend the term of your lease, as appropriate, to allow this to occur.

ACTIVITIES UNDER AN APPROVED SAP

§ 585.614 When may I begin conducting activities under my approved SAP?

(a) You may begin conducting the activities approved in your SAP following BOEM approval of your SAP.

(b) If you are installing a facility or a combination of facilities deemed by BOEM to be complex or significant, as provided in § 585.613(a)(1), you must comply with the requirements of subpart G of this part and submit your Safety Management System required by § 585.810 before construction may begin.

§ 585.615 What other reports or notices must I submit to BOEM under my approved SAP?

(a) You must notify BOEM in writing within 30 days of completing installation activities approved in your SAP.

(b) You must prepare and submit to BOEM a report annually on November 1 of each year that summarizes your site assessment activities and the results of those activities. BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and as provided in § 585.113.

(c) You must submit a certification of compliance annually (or other frequency as determined by BOEM) with certain terms and conditions of your SAP that BOEM identifies under § 585.613(e)(1). Together with your certification, you must submit:

(1) Summary reports that show compliance with the terms and conditions which require certification; and

(2) A statement identifying and describing any mitigation measures and

monitoring methods and their effectiveness. If you identified measures that were not effective, you must include your recommendations for new mitigation measures or monitoring methods.

§ 585.616 [Reserved]

§ 585.617 What activities require a revision to my SAP, and when will BOEM approve the revision?

(a) You must notify BOEM in writing before conducting any activities not described in your approved SAP, describing in detail the type of activities you propose to conduct. We will determine whether the activities you propose are authorized by your existing SAP or require a revision to your SAP. We may request additional information from you, if necessary, to make this determination.

(b) BOEM will periodically review the activities conducted under an approved SAP. The frequency and extent of the review will be based on the significance of any changes in available information and on onshore or offshore conditions affecting, or affected by, the activities conducted under your SAP. If the review indicates that the SAP should be revised to meet the requirements of this part, we will require you to submit the needed revisions.

(c) Activities for which a proposed revision to your SAP will likely be necessary include:

(1) Activities not described in your approved SAP;

(2) Modifications to the size or type of facility or equipment you will use;

(3) Changes in the surface location of a facility or structure;

(4) Addition of a facility or structure not contemplated in your approved SAP;

(5) Changes in the location of your onshore support base from one State to another, or to a new base requiring expansion;

(6) Changes in the location of bottom disturbances (anchors, chains, *etc.*) by 500 feet (152 meters) or greater from the approved locations. If a specific anchor pattern was approved as a mitigation measure to avoid contact with bottom features, any change in the proposed bottom disturbances would likely trigger the need for a revision;

(7) Structural failure of one or more facilities; or

(8) Changes to any other activity specified by BOEM.

(d) We may begin the appropriate NEPA analysis and other relevant consultations when we determine that a proposed revision could:

(1) Result in a significant change in the impacts previously identified and evaluated;

(2) Require any additional Federal authorizations; or

(3) Involve activities not previously identified and evaluated.

(e) When you propose a revision, we may approve the revision if we determine that the revision is:

(1) Designed not to cause undue harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance; and

(2) Otherwise consistent with the provisions of subsection 8(p) of the OCS Lands Act.

§ 585.618 What must I do upon completion of approved site assessment activities?

(a) If, prior to the expiration of your site assessment term, you timely submit a COP meeting the requirements of this subpart, or a complete FERC license application, that describes the continued use of existing facilities approved in your SAP, you may keep such facilities in place on your lease during the time that BOEM reviews your COP for approval or FERC reviews your license application for approval.

(b) You are not required to initiate the decommissioning process for facilities that are authorized to remain in place under your approved COP or approved FERC license.

(c) If, following the technical and environmental review of your submitted COP, BOEM determines that such facilities may not remain in place, you must initiate the decommissioning process, as provided in subpart I of this part.

(d) If FERC determines that such facilities may not remain in place, you must initiate the decommissioning

process as provided in subpart I of this part.

(e) You must initiate the decommissioning process, as set forth in subpart I of this part, upon the termination of your lease.

§ 585.619 [Reserved]

CONSTRUCTION AND OPERATIONS PLAN FOR COMMERCIAL LEASES

§ 585.620 What is a Construction and Operations Plan (COP)?

The COP describes your construction, operations, and conceptual decommissioning plans under your commercial lease, including your project easement. BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and in accordance with the terms of § 585.113.

(a) Your COP must describe all planned facilities that you will construct and use for your project, including onshore and support facilities and all anticipated project easements.

(b) Your COP must describe all proposed activities including your proposed construction activities, commercial operations, and conceptual decommissioning plans for all planned facilities, including onshore and support facilities.

(c) You must receive BOEM approval of your COP before you can begin any of the approved activities on your lease.

§ 585.621 What must I demonstrate in my COP?

Your COP must demonstrate that you have planned and are prepared to conduct the proposed activities in a manner that conforms to your responsibilities listed in § 585.105(a) and:

(a) Conforms to all applicable laws, implementing regulations, lease provisions, and stipulations or conditions of your commercial lease;

(b) Is safe;

(c) Does not unreasonably interfere with other uses of the OCS, including those involved with National security or defense;

(d) Does not cause undue harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(e) Uses best available and safest technology;

(f) Uses best management practices; and

(g) Uses properly trained personnel.

§ 585.622 How do I submit my COP?

(a) You must submit one paper copy and one electronic version of your COP to BOEM at the address listed in § 585.110(a).

(b) You may submit information and a request for any project easement as part of your original COP submission or as a revision to your COP.

§§ 585.623–585.625 [Reserved]

CONTENTS OF THE CONSTRUCTION AND OPERATIONS PLAN

§ 585.626 What must I include in my COP?

(a) You must submit the results of the following surveys for the proposed site(s) of your facility(ies). Your COP must include the following information:

Information:	Report contents:	Including:
(1) Shallow hazards	The results of the shallow hazards survey with supporting data.	Information sufficient to determine the presence of the following features and their likely effects on your proposed facility, including: (i) Shallow faults; (ii) Gas seeps or shallow gas; (iii) Slump blocks or slump sediments; (iv) Hydrates; or (v) Ice scour of seabed sediments.

Information:	Report contents:	Including:
(2) Geological survey relevant to the design and siting of your facility.	The results of the geological survey with supporting data.	Assessment of: (i) Seismic activity at your proposed site; (ii) Fault zones; (iii) The possibility and effects of seabed subsidence; and (iv) The extent and geometry of faulting attenuation effects of geologic conditions near your site.
(3) Biological	The results of the biological survey with supporting data.	A description of the results of biological surveys used to determine the presence of live bottoms, hard bottoms, and topographic features, and surveys of other marine resources such as fish populations (including migratory populations), marine mammals, sea turtles, and sea birds.
(4) Geotechnical survey	The results of your sediment testing program with supporting data, the various field and laboratory test methods employed, and the applicability of these methods as they pertain to the quality of the samples, the type of sediment, and the anticipated design application. You must explain how the engineering properties of each sediment stratum affect the design of your facility. In your explanation, you must describe the uncertainties inherent in your overall testing program, and the reliability and applicability of each test method.	(i) The results of a testing program used to investigate the stratigraphic and engineering properties of the sediment that may affect the foundations or anchoring systems for your facility. (ii) The results of adequate *in situ* testing, boring, and sampling at each foundation location, to examine all important sediment and rock strata to determine its strength classification, deformation properties, and dynamic characteristics. (iii) The results of a minimum of one deep boring (with soil sampling and testing) at each edge of the project area and within the project area as needed to determine the vertical and lateral variation in seabed conditions and to provide the relevant geotechnical data required for design.
(5) Archaeological resources.	The results of the archaeological resource survey with supporting data.	A description of the historic and prehistoric archaeological resources, as required by the NHPA (16 U.S.C. 470 *et. seq.*), as amended.
(6) Overall site investigation.	An overall site investigation report for your facility that integrates the findings of your shallow hazards surveys and geologic surveys, and, if required, your subsurface surveys with supporting data.	An analysis of the potential for: (i) Scouring of the seabed; (ii) Hydraulic instability; (iii) The occurrence of sand waves; (iv) Instability of slopes at the facility location; (v) Liquefaction, or possible reduction of sediment strength due to increased pore pressures; (vi) Degradation of subsea permafrost layers; (vii) Cyclic loading; (viii) Lateral loading; (ix) Dynamic loading; (x) Settlements and displacements; (xi) Plastic deformation and formation collapse mechanisms; and (xii) Sediment reactions on the facility foundations or anchoring systems.

(b) Your COP must include the following project-specific information, as applicable.

Project information:	Including:
(1) Contact information	The name, address, e-mail address, and phone number of an authorized representative.
(2) Designation of operator, if applicable	As provided in § 585.405.
(3) The construction and operation concept	A discussion of the objectives, description of the proposed activities, tentative schedule from start to completion, and plans for phased development, as provided in § 585.629.
(4) Commercial lease stipulations and compliance	A description of the measures you took, or will take, to satisfy the conditions of any lease stipulations related to your proposed activities.
(5) A location plat	The surface location and water depth for all proposed and existing structures, facilities, and appurtenances located both offshore and onshore, including all anchor/mooring data.

Project information:	Including:
(6) General structural and project design, fabrication, and installation.	Information for each type of structure associated with your project and, unless BOEM provides otherwise, how you will use a CVA to review and verify each stage of the project.
(7) All cables and pipelines, including cables on project easements.	Location, design and installation methods, testing, maintenance, repair, safety devices, exterior corrosion protection, inspections, and decommissioning.
(8) A description of the deployment activities	Safety, prevention, and environmental protection features or measures that you will use.
(9) A list of solid and liquid wastes generated	Disposal methods and locations.
(10) A listing of chemical products used (if stored volume exceeds Environmental Protection Agency (EPA) Reportable Quantities).	A list of chemical products used; the volume stored on location; their treatment, discharge, or disposal methods used; and the name and location of the onshore waste receiving, treatment, and/or disposal facility. A description of how these products would be brought onsite, the number of transfers that may take place, and the quantity that that will be transferred each time.
(11) A description of any vessels, vehicles, and aircraft you will use to support your activities.	An estimate of the frequency and duration of vessel/vehicle/aircraft traffic.
(12) A general description of the operating procedures and systems.	(i) Under normal conditions. (ii) In the case of accidents or emergencies, including those that are natural or manmade.
(13) Decommissioning and site clearance procedures	A discussion of general concepts and methodologies.
(14) A listing of all Federal, State, and local authorizations, approvals, or permits that are required to conduct the proposed activities, including commercial operations.	(i) The U.S. Coast Guard, U.S. Army Corps Of Engineers, and any other applicable authorizations, approvals, or permits, including any Federal, State or local authorizations pertaining to energy gathering, transmission or distribution (e.g., interconnection authorizations). (ii) A statement indicating whether you have applied for or obtained such authorization, approval, or permit.
(15) Your proposed measures for avoiding, minimizing, reducing, eliminating, and monitoring environmental impacts.	A description of the measures you will use to avoid or minimize adverse effects and any potential incidental take before you conduct activities on your lease, and how you will mitigate environmental impacts from your proposed activities, including a description of the measures you will use as required by subpart H of this part.
(16) Information you incorporate by reference	A listing of the documents you referenced.
(17) A list of agencies and persons with whom you have communicated, or with whom you will communicate, regarding potential impacts associated with your proposed activities.	Contact information and issues discussed.
(18) Reference	A list of any document or published source that you cite as part of your plan. You may reference information and data discussed in other plans you previously submitted or that are otherwise readily available to BOEM.
(19) Financial assurance	Statements attesting that the activities and facilities proposed in your COP are or will be covered by an appropriate bond or security, as required by §§ 585.515 and 585.516.
(20) CVA nominations for reports required in subpart G of this part.	CVA nominations for reports in subpart G of this part, as required by § 585.706, or a request for a waiver under § 585.705(c).
(21) Construction schedule	A reasonable schedule of construction activity showing significant milestones leading to the commencement of commercial operations.
(22) Air quality information	As described in § 585.659 of this section.
(23) Other information	Additional information as required by BOEM.

§ 585.627 What information and certifications must I submit with my COP to assist the BOEM in complying with NEPA and other relevant laws?

(a) You must submit with your COP detailed information to assist BOEM in complying with NEPA and other relevant laws. Your COP must describe those resources, conditions, and activities listed in the following table that could be affected by your proposed activities, or that could affect the activities proposed in your COP, including:

Type of information:	Including:
(1) Hazard information	Meteorology, oceanography, sediment transport, geology, and shallow geological or manmade hazards.
(2) Water quality	Turbidity and total suspended solids from construction.

Type of information:	Including:
(3) Biological resources	Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, plankton, seagrasses, and plant life.
(4) Threatened or endangered species.	As defined by the ESA (16 U.S.C. 1531 *et seq.*).
(5) Sensitive biological resources or habitats.	Essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, hard bottom habitat, chemosynthetic communities, calving grounds, barrier islands, beaches, dunes, and wetlands.
(6) Archaeological resources	As required by the NHPA (16 U.S.C. 470 *et seq.*), as amended.
(7) Social and economic resources.	Employment, existing offshore and coastal infrastructure (including major sources of supplies, services, energy, and water), land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including typical fishing seasons, location, and type), minority and lower income groups, coastal zone management programs, and viewshed.
(8) Coastal and marine uses	Military activities, vessel traffic, and energy and nonenergy mineral exploration or development.
(9) Consistency Certification	As required by the CZMA regulations: (i) 15 CFR part 930, subpart D, if your COP is submitted before lease issuance. (ii) 15 CFR part 930, subpart E, if your COP is submitted after lease issuance.
(10) Other resources, conditions, and activities.	As identified by BOEM.

(b) You must submit one paper copy and one electronic copy of your consistency certification. Your consistency certification must include:

(1) One copy of your consistency certification under either subsection 307(c)(3)(B) of the CZMA (16 U.S.C. 1456(c)(3)(B)) and 15 CFR 930.76 or subsection 307(c)(3)(A) of the CZMA (16 U.S.C. 1456(c)(3)(A)) and 15 CFR 930.57, stating that the proposed activities described in detail in your plans comply with the State(s) approved coastal management program(s) and will be conducted in a manner that is consistent with such program(s); and

(2) ''Necessary data and information,'' as required by 15 CFR 930.58.

(c) You must submit your oil spill response plan, as required by 30 CFR part 254.

(d) You must submit your Safety Management System as required by § 585.810.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21624, Apr. 17, 2014]

§ 585.628 How will BOEM process my COP?

(a) BOEM will review your submitted COP, and the information provided pursuant to § 585.627, to determine if it contains all the required information necessary to conduct our technical and environmental reviews. We will notify you if your submitted COP lacks any necessary information.

(b) BOEM will prepare an appropriate NEPA analysis.

(c) If your COP is submitted after lease issuance, BOEM will forward one copy of your COP, consistency certification, and associated data and information under the CZMA to the applicable State CZMA agency or agencies after all information requirements for the COP are met.

(d) As appropriate, BOEM will coordinate and consult with relevant Federal, State, and local agencies and affected Indian Tribes, and provide to them relevant nonproprietary data and information pertaining to your proposed activities.

(e) During the review process, we may request additional information if we determine that the information provided is not sufficient to complete the review and approval process. If you fail to provide the requested information, BOEM may disapprove your COP.

(f) Upon completion of our technical and environmental reviews and other reviews required by Federal law (e.g., CZMA), BOEM may approve, disapprove, or approve with modifications your COP.

(1) If we approve your COP, we will specify terms and conditions to be incorporated into your COP. You must certify compliance with certain of those terms and conditions, as required under § 585.633(b); and

(2) If we disapprove your COP, we will inform you of the reasons and allow you an opportunity to resubmit a revised plan addressing the concerns identified, and may suspend the term

of your lease, as appropriate, to allow this to occur.

(g) If BOEM approves your project easement, BOEM will issue an addendum to your lease specifying the terms of the project easement. A project easement may include off-lease areas that:

(1) Contain the sites on which cable, pipeline, or associated facilities are located;

(2) Do not exceed 200 feet (61 meters) in width, unless safety and environmental factors during construction and maintenance of the associated cables or pipelines require a greater width; and

(3) For associated facilities, are limited to the area reasonably necessary for power or pumping stations or other accessory facilities.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21625, Apr. 17, 2014]

§ 585.629 May I develop my lease in phases?

In your COP, you may request development of your commercial lease in phases. In support of your request, you must provide details as to what portions of the lease will be initially developed for commercial operations and what portions of the lease will be reserved for subsequent phased development.

§ 585.630 [Reserved]

ACTIVITIES UNDER AN APPROVED COP

§ 585.631 When must I initiate activities under an approved COP?

After your COP is approved, you must commence construction by the date given in the construction schedule required by § 585.626(b)(21), and included as a part of your approved COP, unless BOEM approves a deviation from your schedule.

§ 585.632 What documents must I submit before I may construct and install facilities under my approved COP?

(a) You must submit to BOEM the documents listed in the following table:

Document:	Requirements are found in:
(1) Facility Design Report	§ 585.701
(2) Fabrication and Installation Report	§ 585.702

(b) You must submit your Safety Management System, as required by § 585.810 of this part.

(c) These activities must fall within the scope of your approved COP. If they do not fall within the scope of your approved COP, you will be required to submit a revision to your COP, under § 585.634, for BOEM approval before commencing the activity.

§ 585.633 How do I comply with my COP?

(a) Based on BOEM's environmental and technical reviews, we will specify terms and conditions to be incorporated into your COP.

(b) You must submit a certification of compliance annually (or other frequency as determined by BOEM) with certain terms and conditions of your COP that BOEM identifies. Together with your certification, you must submit:

(1) Summary reports that show compliance with the terms and conditions which require certification; and

(2) A statement identifying and describing any mitigation measures and monitoring methods, and their effectiveness. If you identified measures that were not effective, then you must make recommendations for new mitigation measures or monitoring methods.

(c) As provided at § 585.105(i), BOEM may require you to submit any supporting data and information.

§ 585.634 What activities require a revision to my COP, and when will BOEM approve the revision?

(a) You must notify BOEM in writing before conducting any activities not described in your approved COP, describing in detail the type of activities you propose to conduct. We will determine whether the activities you propose are authorized by your existing COP or require a revision to your COP. We may request additional information from you, if necessary, to make this determination.

(b) BOEM will periodically review the activities conducted under an approved

COP. The frequency and extent of the review will be based on the significance of any changes in available information, and on onshore or offshore conditions affecting, or affected by, the activities conducted under your COP. If the review indicates that the COP should be revised to meet the requirement of this part, we will require you to submit the needed revisions.

(c) Activities for which a proposed revision to your COP will likely be necessary include:

(1) Activities not described in your approved COP;

(2) Modifications to the size or type of facility or equipment you will use;

(3) Change in the surface location of a facility or structure;

(4) Addition of a facility or structure not described in your approved COP;

(5) Change in the location of your onshore support base from one State to another or to a new base requiring expansion;

(6) Changes in the location of bottom disturbances (anchors, chains, *etc.*) by 500 feet (152 meters) or greater from the approved locations (e.g., if a specific anchor pattern was approved as a mitigation measure to avoid contact with bottom features, any change in the proposed bottom disturbances would likely trigger the need for a revision);

(7) Structural failure of one or more facilities; or

(8) Change in any other activity specified by BOEM.

(d) We may begin the appropriate NEPA analysis and relevant consultations when we determine that a proposed revision could:

(1) Result in a significant change in the impacts previously identified and evaluated;

(2) Require any additional Federal authorizations; or

(3) Involve activities not previously identified and evaluated.

(e) When you propose a revision, we may approve the revision if we determine that the revision is:

(1) Designed not to cause undue harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance; and

(2) Otherwise consistent with the provisions of subsection 8(p) of the OCS Lands Act.

§ 585.635 What must I do if I cease activities approved in my COP before the end of my commercial lease?

You must notify the BOEM, within 5 business days, any time you cease commercial operations, without an approved suspension, under your approved COP. If you cease commercial operations for an indefinite period which extends longer than 6 months, we may cancel your lease under § 585.437 and, you must initiate the decommissioning process as set forth in subpart I of this part.

§ 585.636 What notices must I provide BOEM following approval of my COP?

You must notify BOEM in writing of the following events, within the time periods provided:

(a) No later than 30 days after commencing activities associated with the placement of facilities on the lease area under a Fabrication and Installation Report.

(b) No later than 30 days after completion of construction and installation activities under a Fabrication and Installation Report.

(c) At least 7 days before commencing commercial operations.

§ 585.637 When may I commence commercial operations on my commercial lease?

If you are conducting activities on your lease that:

(a) Do not require a FERC license (*i.e.*, wind), then you may commence commercial operations 30 days after the CVA or project engineer has submitted to BOEM the final Fabrication and Installation Report for the fabrication and installation review, as provided in § 585.708.

(b) Require a FERC license or exemption, then you may commence commercial operations when permitted by the terms of your license or exemption.

§ 585.638 What must I do upon completion of my commercial operations as approved in my COP or FERC license?

(a) Upon completion of your approved activities under your COP, you must initiate the decommissioning process as set forth in subpart I of this part. You must submit your decommissioning application as provided in §§ 585.905 and 585.906.

(b) Upon completion of your approved activities under your FERC license, the terms of your FERC license will govern your decommissioning activities.

§ 585.639 [Reserved]

GENERAL ACTIVITIES PLAN REQUIREMENTS FOR LIMITED LEASES, ROW GRANTS, AND RUE GRANTS

§ 585.640 What is a General Activities Plan (GAP)?

(a) A GAP describes your proposed construction, activities, and conceptual decommissioning plans for all planned facilities, including testing of technology devices and onshore and support facilities that you will construct and use for your project, including any project easements for the assessment and development of your limited lease or grant.

(b) You must receive BOEM approval of your GAP before you can begin any of the approved activities on your lease or grant. You must submit your GAP no later than 12 months from the date of the lease or grant issuance.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21625, Apr. 17, 2014]

§ 585.641 What must I demonstrate in my GAP?

Your GAP must demonstrate that you have planned and are prepared to conduct the proposed activities in a manner that:

(a) Conforms to all applicable laws, implementing regulations, lease provisions and stipulations;

(b) Is safe;

(c) Does not unreasonably interfere with other uses of the OCS, including those involved with National security or defense;

(d) Does not cause undue harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(e) Uses best available and safest technology;

(f) Uses best management practices; and

(g) Uses properly trained personnel.

§ 585.642 How do I submit my GAP?

(a) You must submit one paper copy and one electronic version of your GAP to BOEM at the address listed in § 585.110(a).

(b) If you have a limited lease, you may submit information on any project easement as part of your original GAP submission or as a revision to your GAP.

§§ 585.643–585.644 [Reserved]

CONTENTS OF THE GENERAL ACTIVITIES PLAN

§ 585.645 What must I include in my GAP?

(a) You must provide the following results of geophysical and geological surveys, hazards surveys, archaeological surveys (if required), and baseline collection studies (e.g., biological) with the supporting data in your GAP:

Information:	Report contents:	Including:
(1) Geotechnical	The results from the geotechnical survey with supporting data.	A description of all relevant seabed and engineering data and information to allow for the design of the foundation for that facility. You must provide data and information to depths below which the underlying conditions will not influence the integrity or performance of the structure. This could include a series of sampling locations (borings and in situ tests) as well as laboratory testing of soil samples, but may consist of a minimum of one deep boring with samples.

Information:	Report contents:	Including:
(2) Shallow hazards	The results from the shallow hazards survey with supporting data.	A description of information sufficient to determine the presence of the following features and their likely effects on your proposed facility, including: (i) Shallow faults; (ii) Gas seeps or shallow gas; (iii) Slump blocks or slump sediments; (iv) Hydrates; or (v) Ice scour of seabed sediments.
(3) Archaeological resources.	The results from the archaeological survey with supporting data, if required.	(i) A description of the results and data from the archaeological survey; (ii) A description of the historic and prehistoric archaeological resources, as required by NHPA (16 U.S.C. 470 *et seq.*), as amended.
(4) Geological survey	The results from the geological survey with supporting data.	A report that describes the results of a geological survey that includes descriptions of: (i) Seismic activity at your proposed site; (ii) Fault zones; (iii) The possibility and effects of seabed subsidence; and (iv) The extent and geometry of faulting attenuation effects of geologic conditions near your site.
(5) Biological survey	The results from the biological survey with supporting data.	A description of the results of a biological survey, including the presence of live bottoms, hard bottoms, and topographic features, and surveys of other marine resources such as fish populations (including migratory populations), marine mammals, sea turtles, and sea birds.

(b) For all activities you propose to conduct under your GAP, you must provide the following information:

Project information:	Including:
(1) Contact information	The name, address, e-mail address, and phone number of an authorized representative.
(2) The site assessment or technology testing concept	A discussion of the objectives; description of the proposed activities, including the technology you will use; and proposed schedule from start to completion.
(3) Designation of operator, if applicable	As provided in § 585.405.
(4) ROW, RUE or limited lease grant stipulations, if known	A description of the measures you took, or will take, to satisfy the conditions of any lease stipulations related to your proposed activities.
(5) A location plat	The surface location and water depth for all proposed and existing structures, facilities, and appurtenances located both offshore and onshore.
(6) General structural and project design, fabrication, and installation.	Information for each type of facility associated with your project.
(7) Deployment activities	A description of the safety, prevention, and environmental protection features or measures that you will use.
(8) A list of solid and liquid wastes generated	Disposal methods and locations.
(9) A listing of chemical products used (only if stored volume exceeds USEPA Reportable Quantities).	A list of chemical products used; the volume stored on location; their treatment, discharge, or disposal methods used; and the name and location of the onshore waste receiving, treatment, and/or disposal facility. A description of how these products would be brought onsite, the number of transfers that may take place, and the quantity that will be transferred each time.
(10) Reference information	A list of any document or published source that you cite as part of your plan. You may reference information and data discussed in other plans you previously submitted or that are otherwise readily available to BOEM.
(11) Decommissioning and site clearance procedures	A discussion of methodologies.
(12) Air quality information	As described in § 585.659 of this section.
(13) A listing of all Federal, State, and local authorizations or approvals required to conduct site assessment activities on your lease.	A statement indicating whether such authorization or approval has been applied for or obtained.
(14) A list of agencies and persons with whom you have communicated, or with whom you will communicate, regarding potential impacts associated with your proposed activities.	Contact information and issues discussed.

Project information:	Including:
(15) Financial assurance information	Statements attesting that the activities and facilities proposed in your GAP are or will be covered by an appropriate bond or other approved security, as required in §§ 585.520 and 585.521.
(16) Other information	Additional information as requested by BOEM.

(c) If you are applying for a project easement or constructing a facility, or a combination of facilities deemed by BOEM to be complex or significant, you must provide the following information in addition to what is required in paragraphs (a) and (b) of this section and comply with the requirements of subpart G of this part:

Project information:	Including:
(1) The construction and operation concept	A discussion of the objectives, description of the proposed activities, and tentative schedule from start to completion.
(2) All cables and pipelines, including cables on project easements.	The location, design, installation methods, testing, maintenance, repair, safety devices, exterior corrosion protection, inspections, and decommissioning.
(3) A description of the deployment activities	Safety, prevention, and environmental protection features or measures that you will use.
(4) A general description of the operating procedures and systems.	(i) Under normal conditions. (ii) In the case of accidents or emergencies, including those that are natural or manmade.
(5) CVA nominations for reports required in subpart G of this part.	CVA nominations for reports in subpart G of this part, as required by § 585.706, or a request for a waiver under § 585.705(c).
(6) Construction schedule	A reasonable schedule of construction activity showing significant milestones leading to the commencement of activities.
(7) Other information	Additional information as required by the BOEM.

(d) BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure in accordance with the terms of § 585.113.

§ 585.646 What information and certifications must I submit with my GAP to assist BOEM in complying with NEPA and other relevant laws?

You must submit, with your GAP, detailed information to assist BOEM in complying with NEPA and other relevant laws as appropriate.

(a) A GAP submitted for an area in which BOEM has not reviewed GAP activities under NEPA or other applicable Federal laws must describe those resources, conditions, and activities listed in the following table that could be affected by your proposed activities or that could affect the activities proposed in your GAP.

(b) For a GAP submitted for an area in which BOEM has considered GAP activities under applicable Federal law (e.g., a NEPA analysis and CZMA consistency determination for the GAP activities), BOEM will review the GAP to determine if its impacts are consistent with those previously considered. If the anticipated effects of your proposed GAP activities are significantly different than those previously anticipated, we may determine that additional NEPA and other relevant Federal reviews are required. In that case, BOEM will notify you of such determination, and you must submit a GAP that describes those resources, conditions, and activities listed in the following table that could be affected by your proposed activities or that could affect the activities proposed in your GAP, including:

Type of information:	Including:
(1) Hazard information	Meteorology, oceanography, sediment transport, geology, and shallow geological or manmade hazards.
(2) Water quality	Turbidity and total suspended solids from construction.
(3) Biological resources	Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, plankton, sea grasses, and other plant life.

Type of information:	Including:
(4) Threatened or endangered species.	As required by the ESA (16 U.S.C. 1531 *et seq.*).
(5) Sensitive biological resources or habitats.	Essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, hard bottom habitat, chemosynthetic communities, calving grounds, barrier islands, beaches, dunes, and wetlands.
(6) Archaeological resources	As required by NHPA (16 U.S.C. 470 *et seq.*), as amended.
(7) Social and economic conditions.	Employment, existing offshore and coastal infrastructure (including major sources of supplies, services, energy, and water), land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including typical fishing seasons, location, and type), minority and lower income groups, coastal zone management programs, and viewshed.
(8) Coastal and marine uses	Military activities, vessel traffic, and energy and non-energy mineral exploration or development.
(9) Consistency Certification	If required by CZMA, as appropriate: (A) 15 CFR part 930, subpart D, if the GAP is submitted prior to lease or grant issuance; (B) 15 CFR part 930, subpart E, if the GAP is submitted after lease or grant issuance.
(10) Other resources, conditions, and activities.	As required by BOEM.

[79 FR 21625, Apr. 17, 2014]

§ 585.647 How will my GAP be processed for Federal consistency under the Coastal Zone Management Act?

Your GAP will be processed based on whether it is submitted before or after your lease or grant is issued:

If your GAP is submitted:	Consistency review of your GAP will be handled as follows:
(a) Before lease or grant issuance.	You will furnish a copy of your GAP, consistency certification, and necessary data and information pursuant to 15 CFR part 930, subpart D, to the applicable State CZMA agency or agencies and BOEM at the same time.
(b) After lease or grant issuance.	You will submit a copy of your GAP, consistency certification, and necessary data and information pursuant to 15 CFR 930, subpart E to BOEM. BOEM will forward to the applicable State CZMA agency or agencies one paper copy and one electronic copy of your GAP, consistency certification, and necessary data and information required under 15 CFR part 930, subpart E, after BOEM has determined that all information requirements for the GAP are met.

[79 FR 21625, Apr. 17, 2014]

§ 585.648 How will BOEM process my GAP?

(a) BOEM will review your submitted GAP, along with the information and certifications provided pursuant to § 585.646, to determine if it contains all the required information necessary to conduct our technical and environmental reviews.

(1) We will notify you if we deem your proposed facility or combination of facilities to be complex or significant; and

(2) We will notify you if your submitted GAP lacks any necessary information.

(b) BOEM will prepare appropriate NEPA analysis.

(c) When appropriate, we will coordinate and consult with relevant State and Federal agencies and affected Indian Tribes and provide to other local, State, and Federal agencies and affected Indian Tribes relevant nonproprietary data and information pertaining to your proposed activities.

(d) During the review process, we may request additional information if we determine that the information provided is not sufficient to complete the review and approval process. If you fail to provide the requested information, BOEM may disapprove your GAP.

(e) Upon completion of our technical and environmental reviews and other reviews required by Federal law (e.g., CZMA), BOEM may approve, disapprove, or approve with modifications your GAP.

(1) If we approve your GAP, we will specify terms and conditions to be incorporated into your GAP. You must

certify compliance with certain of those terms and conditions, as required under § 585.653(c); and

(2) If we disapprove your GAP, we will inform you of the reasons and allow you an opportunity to resubmit a revised plan making the necessary corrections, and may suspend the term of your lease or grant, as appropriate, to allow this to occur.

§ 585.649 [Reserved]

ACTIVITIES UNDER AN APPROVED GAP

§ 585.650 When may I begin conducting activities under my GAP?

After BOEM approves your GAP, you may begin conducting the approved activities that do not involve a project easement or the construction of facilities on the OCS that BOEM has deemed to be complex or significant.

§ 585.651 When may I construct complex or significant OCS facilities on my limited lease or any facilities on my project easement proposed under my GAP?

If you are applying for a project easement, or installing a facility or a combination of facilities on your limited lease deemed by BOEM to be complex or significant, as provided in § 585.648(a)(1), you also must comply with the requirements of subpart G of this part and submit your Safety Management System description required by § 585.810 before construction may begin.

§ 585.652 How long do I have to conduct activities under an approved GAP?

After BOEM approves your GAP, you have:

(a) For a limited lease, 5 years to conduct your approved activities, unless we renew the term under §§ 585.425 through 585.429.

(b) For a ROW grant or RUE grant, the time provided in the terms of the grant.

§ 585.653 What other reports or notices must I submit to BOEM under my approved GAP?

(a) You must notify BOEM in writing within 30 days after completing installation activities approved in your GAP.

(b) You must prepare and submit to BOEM annually a report that summarizes the findings from any activities you conduct under your approved GAP and the results of those activities. We will protect the information from public disclosure as provided in § 585.113.

(c) You must annually (or other frequency as determined by BOEM) submit a certification of compliance with those terms and conditions of your GAP that BOEM identifies under § 585.648(e)(1). Together with your certification, you must submit:

(1) Summary reports that show compliance with the terms and conditions which require certification; and

(2) A statement identifying and describing any mitigation measures and monitoring methods and their effectiveness. If you identified measures that were not effective, you must include your recommendations for new mitigation measures or monitoring methods.

§ 585.654 [Reserved]

§ 585.655 What activities require a revision to my GAP, and when will BOEM approve the revision?

(a) You must notify BOEM in writing before conducting any activities not described in your approved GAP, describing in detail the type of activities you propose to conduct. We will determine whether the activities you propose are authorized by your existing GAP or require a revision to your GAP. We may request additional information from you, if necessary, to make this determination.

(b) BOEM will periodically review the activities conducted under an approved GAP. The frequency and extent of the review will be based on the significance of any changes in available information and on onshore or offshore conditions affecting, or affected by, the activities conducted under your GAP. If the review indicates that the GAP should be revised to meet the requirement of this part, we will require you to submit the needed revisions.

(c) Activities for which a proposed revision to your GAP will likely be necessary include:

(1) Activities not described in your approved GAP;

(2) Modifications to the size or type of facility or equipment you will use;

(3) Change in the surface location of a facility or structure;

(4) Addition of a facility or structure not contemplated in your approved GAP;

(5) Change in the location of your onshore support base from one State to another or to a new base requiring expansion;

(6) Changes in the locations of bottom disturbances (anchors, chains, *etc.*) by 500 feet (152 meters) or greater from the approved locations. If a specific anchor pattern was approved as a mitigation measure to avoid contact with bottom features, any change in the proposed bottom disturbances would likely trigger the need for a revision;

(7) Structural failure of one or more facilities; or

(8) Change to any other activity specified by BOEM.

(d) We may begin the appropriate NEPA analysis and any relevant consultations when we determine that a proposed revision could:

(1) Result in a significant change in the impacts previously identified and evaluated;

(2) Require any additional Federal authorizations; or

(3) Involve activities not previously identified and evaluated.

(e) When you propose a revision, we may approve the revision if we determine that the revision is:

(1) Designed not to cause undue harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance; and

(2) Otherwise consistent with the provisions of subsection 8(p) of the OCS Lands Act.

§ 585.656 What must I do if I cease activities approved in my GAP before the end of my term?

You must notify the BOEM any time you cease activities under your approved GAP without an approved suspension. If you cease activities for an indefinite period that exceeds 6 months, BOEM may cancel your lease or grant under § 585.437, as applicable, and you must initiate the decommissioning process, as set forth in subpart I of this part.

§ 585.657 What must I do upon completion of approved activities under my GAP?

Upon completion of your approved activities under your GAP, you must initiate the decommissioning process as set forth in subpart I of this part. You must submit your decommissioning application as provided in §§ 585.905 and 585.906.

CABLE AND PIPELINE DEVIATIONS

§ 585.658 Can my cable or pipeline construction deviate from my approved COP or GAP?

(a) You must make every effort to ensure that all cables and pipelines are constructed in a manner that minimizes deviations from the approved plan under your lease or grant.

(b) If BOEM determines that a significant change in conditions has occurred that would necessitate an adjustment to your ROW, RUE or lease before the commencement of construction of the cable or pipeline on the grant or lease, BOEM will consider modifications to your ROW grant, RUE grant, or your lease addendum for a project easement in connection with your COP or GAP.

(c) If, after construction, it is determined that a deviation from the approved plan has occurred, you must:

(1) Notify the operators of all leases (including mineral leases issued under this subchapter) and holders of all ROW grants or RUE grants (including all grants issued under this subchapter) which include the area where a deviation has occurred and provide BOEM with evidence of such notification;

(2) Relinquish any unused portion of your lease or grant; and

(3) Submit a revised plan for BOEM approval as necessary.

(d) Construction of a cable or pipeline that substantially deviates from the approved plan may be grounds for cancellation of the lease or grant.

§ 585.659 What requirements must I include in my SAP, COP, or GAP regarding air quality?

(a) You must comply with the Clean Air Act (42 U.S.C. 7409) and its implementing regulations, according to the following table.

If your project is located . . .	you must . . .
(1) in the Gulf of Mexico west of 87.5° west longitude (western Gulf of Mexico).	include in your plan any information required for BOEM to make the appropriate air quality determinations for your project.
(2) anywhere else on the OCS	follow the appropriate implementing regulations as promulgated by the EPA under 40 CFR part 55.

(b) For air quality modeling that you perform in support of the activities proposed in your plan, you should contact the appropriate regulatory agency to establish a modeling protocol to ensure that the agency's needs are met and that the meteorological files used are acceptable before initiating the modeling work. In the western Gulf of Mexico (west of 87.5° west longitude), you must submit to BOEM three copies of the modeling report and three sets of digital files as supporting information. The digital files must contain the formatted meteorological files used in the modeling runs, the model input file, and the model output file.

Subpart G—Facility Design, Fabrication, and Installation

REPORTS

§ 585.700 What reports must I submit to BOEM before installing facilities described in my approved SAP, COP, or GAP?

(a) You must submit the following reports to BOEM before installing facilities described in your approved COP (§ 585.632(a)) and, when required by this part, your SAP (§ 585.614(b)) or GAP (§ 585.651):

(1) A Facility Design Report; and

(2) A Fabrication and Installation Report.

(b) You may begin to fabricate and install the approved facilities after BOEM notifies you that it has received your reports and has no objections. If BOEM receives the reports, but does not respond with objections within 60 days of receipt or 60 days after we approve your SAP, COP, or GAP, if you submitted your report with the plan, BOEM is deemed not to have objections to the reports, and you may commence fabrication and installation of your facility or facilities.

(c) If BOEM has any objections, we will notify you verbally or in writing within 60 days of receipt of the report. Following initial notification of objections, BOEM may follow up with written correspondence outlining its specific objections to the report and request that certain actions be undertaken. You cannot commence activities addressed in such report until you resolve all objections to BOEM's satisfaction.

§ 585.701 What must I include in my Facility Design Report?

(a) Your Facility Design Report provides specific details of the design of any facilities, including cables and pipelines that are outlined in your approved SAP, COP, or GAP. Your Facility Design Report must demonstrate that your design conforms to your responsibilities listed in § 585.105(a). You must include the following items in your Facility Design Report:

Required documents	Required contents	Other requirements
(1) Cover letter	(i) Proposed facility designations; (ii) Lease, ROW grant or RUE grant number; (iii) Area; name and block numbers; and (iv) The type of facility.	You must submit 1 paper copy and 1 electronic copy.

Required documents	Required contents	Other requirements
(2) Location plat	(i) Latitude and longitude coordinates, Universal Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection System; (ii) Distances in feet from the nearest block lines. These coordinates must be based on the NAD (North American Datum) 83 datum plane coordinate system; and (iii) The location of any proposed project easement.	Your plat must be drawn to a scale of 1 inch equals 100 feet and include the coordinates of the lease, ROW grant, or RUE grant block boundary lines. You must submit 1 paper copy and 1 electronic copy.
(3) Front, Side, and Plan View drawings	(i) Facility dimensions and orientation; (ii) Elevations relative to Mean Lower Low Water; and (iii) Pile sizes and penetration.	Your drawing sizes must not exceed 11″ × 17″. You must submit 1 paper copy and 1 electronic copy.
(4) Complete set of structural drawings	The approved for construction fabrication drawings should be submitted including, e.g., (i) Cathodic protection systems; (ii) Jacket design; (iii) Pile foundations; (iv) Mooring and tethering systems; (v) Foundations and anchoring systems; and (vi) Associated cable and pipeline designs.	Your drawing sizes must not exceed 11″ × 17″. You must submit 1 paper copy and 1 electronic copy.
(5) Summary of environmental data used for design.	A summary of the environmental data used in the design or analysis of the facility. Examples of relevant data include information on: (i) Extreme weather; (ii) Seafloor conditions; and (iii) Waves, wind, current, tides, temperature, snow and ice effects, marine growth, and water depth..	You must submit 1 paper copy and 1 electronic copy. If you submitted these data as part of your SAP, COP, or GAP, you may reference the plan.
(6) Summary of the engineering design data.	(i) Loading information (e.g., live, dead, environmental); (ii) Structural information (e.g., design-life; material types; cathodic protection systems; design criteria; fatigue life; jacket design; deck design; production component design; foundation pilings and templates, and mooring or tethering systems; fabrication and installation guidelines); and (iii) Location of foundation boreholes and foundation piles; and (iv) Foundation information (e.g., soil stability, design criteria).	You must submit 1 paper copy and 1 electronic copy.
(7) A complete set of design calculations	Self-explanatory	You must submit 1 paper copy and 1 electronic copy.
(8) Project-specific studies used in the facility design or installation.	All studies pertinent to facility design or installation, e.g., oceanographic and soil reports including the results of the surveys required in §§ 585.610(b), 585.627(a), or 585.645(a).	You must submit 1 paper copy and 1 electronic copy.
(9) Description of the loads imposed on the facility.	(i) Loads imposed by jacket; (ii) Decks; (iii) Production components; (iv) Foundations, foundation pilings and templates, and anchoring systems; and (v) Mooring or tethering systems.	You must submit 1 paper copy and 1 electronic copy.
(10) Geotechnical Report	A list of all data from borings and recommended design parameters.	You must submit 1 paper copy and 1 electronic copy.

(b) For any floating facility, your design must meet the requirements of the U.S. Coast Guard for structural integrity and stability (e.g., verification of

center of gravity). The design must also consider:

(1) Foundations, foundation pilings and templates, and anchoring systems; and

(2) Mooring or tethering systems.

(c) You must provide the location of records, as required in § 585.714(c).

(d) If you are required to use a CVA, the Facility Design Report must include one paper copy of the following certification statement: ''The design of this structure has been certified by a BOEM approved CVA to be in accordance with accepted engineering practices and the approved SAP, GAP, or COP as appropriate. The certified design and as-built plans and specifications will be on file at (given location).''

(e) BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and in accordance with the terms of § 585.113.

§ 585.702 What must I include in my Fabrication and Installation Report?

(a) Your Fabrication and Installation Report must describe how your facilities will be fabricated and installed in accordance with the design criteria identified in the Facility Design Report; your approved SAP, COP, or GAP; and generally accepted industry standards and practices. Your Fabrication and Installation Report must demonstrate how your facilities will be fabricated and installed in a manner that conforms to your responsibilities listed in § 585.105(a). You must include the following items in your Fabrication and Installation Report:

Required documents	Required contents	Other requirements
(1) Cover letter	(i) Proposed facility designation, lease, ROW grant, or RUE grant number; (ii) Area, name, and block number; and (iii) The type of facility.	You must submit 1 paper copy and 1 electronic copy.
(2) Schedule	Fabrication and installation	You must submit 1 paper copy and 1 electronic copy.
(3) Fabrication information	The industry standards you will use to ensure the facilities are fabricated to the design criteria identified in your Facility Design Report.	You must submit 1 paper copy and 1 electronic copy.
(4) Installation process information	Details associated with the deployment activities, equipment, and materials, including onshore and offshore equipment and support, and anchoring and mooring patterns.	You must submit 1 paper copy and 1 electronic copy.
(5) Federal, State, and local permits (e.g., EPA, Army Corps of Engineers).	Either 1 copy of the permit or information on the status of the application.	You must submit 1 paper copy and 1 electronic copy.
(6) Environmental information	(i) Water discharge; (ii) Waste disposal; (iii) Vessel information; and (iv) Onshore waste receiving treatment or disposal facilities.	You must submit 1 paper copy and 1 electronic copy. If you submitted these data as part of your SAP, COP, or GAP, you may reference the plan.
(7) Project easement	Design of any cables, pipelines, or facilities. Information on burial methods and vessels.	You must submit 1 paper copy and 1 electronic copy.

(b) You must provide the location of records, as required in § 585.714(c).

(c) If you are required to use a CVA, the Fabrication and Installation Report must include one paper copy of the following certification statement: ''The fabrication and installation of this structure has been certified by a BOEM approved CVA to be in accordance with accepted engineering practices and the approved SAP, GAP, or COP as appropriate. The certified design and as-built plans and specifications will be on file at (given location).''

(d) BOEM will withhold trade secrets and commercial or financial information that is privileged or confidential from public disclosure under exemption 4 of the FOIA and in accordance with the terms of § 585.113.

§ 585.703 What reports must I submit for project modifications and repairs?

(a) You must verify and, in a report to us, certify that major repairs and major modifications to the project conform to accepted engineering practices.

(1) A major repair is a corrective action involving structural members affecting the structural integrity of a portion of or all the facility.

(2) A major modification is an alteration involving structural members affecting the structural integrity of a portion of or all the facility.

(b) The report must also identify the location of all records pertaining to the major repairs or major modifications, as required in § 585.714(c).

(c) BOEM may require you to use a CVA for project modifications and repairs.

§ 585.704 [Reserved]

CERTIFIED VERIFICATION AGENT

§ 585.705 When must I use a Certified Verification Agent (CVA)?

You must use a CVA to review and certify the Facility Design Report, the Fabrication and Installation Report, and the Project Modifications and Repairs Report.

(a) You must use a CVA to:

(1) Ensure that your facilities are designed, fabricated, and installed in conformance with accepted engineering practices and the Facility Design Report and Fabrication and Installation Report;

(2) Ensure that repairs and major modifications are completed in conformance with accepted engineering practices; and

(3) Provide BOEM immediate reports of all incidents that affect the design, fabrication, and installation of the project and its components.

(b) BOEM may waive the requirement that you use a CVA if you can demonstrate the following:

If you demonstrate that . . .	Then BOEM may waive the requirement for a CVA for the following:
(1) The facility design conforms to a standard design that has been used successfully in a similar environment, and the installation design conforms to accepted engineering practices.	The design of your structure(s).
(2) The manufacturer has successfully manufactured similar facilities, and the facility will be fabricated in conformance with accepted engineering practices.	The fabrication of your structure(s).
(3) The installation company has successfully installed similar facilities in a similar offshore environment, and your structure(s) will be installed in conformance with accepted engineering practices.	The installation of your structure(s).
(4) Repairs and major modifications will be completed in conformance with accepted engineering practices.	The repair or major modification of your structure(s).

(c) You must submit a request to waive the requirement to use a CVA to BOEM in writing, along with your SAP under § 585.610(a)(9), COP under § 585.626(b)(20), or GAP under § 585.645(c)(5).

(1) BOEM will review your request to waive the use of the CVA and notify you of our decision along with our decision on your SAP, COP, or GAP.

(2) If BOEM does not waive the requirement for a CVA, you may file an appeal under § 585.118.

(3) If BOEM waives the requirement that you use a CVA, your project engineer must perform the same duties and responsibilities as the CVA, except as otherwise provided.

§ 585.706 How do I nominate a CVA for BOEM approval?

(a) As part of your COP (as provided in § 585.626(b)(20) and, when required by this part, your SAP (§ 585.610(a)(9)) or GAP (§ 585.645(c)(5)), you must nominate a CVA for BOEM approval. You must specify whether the nomination

is for the Facility Design Report, Fabrication and Installation Report, Modification and Repair Report, or for any combination of these.

(b) For each CVA that you nominate, you must submit to BOEM a list of documents used in your design that you will forward to the CVA and a qualification statement that includes the following:

(1) Previous experience in third-party verification or experience in the design, fabrication, installation, or major modification of offshore energy facilities;

(2) Technical capabilities of the individual or the primary staff for the specific project;

(3) Size and type of organization or corporation;

(4) In-house availability of, or access to, appropriate technology (including computer programs, hardware, and testing materials and equipment);

(5) Ability to perform the CVA functions for the specific project considering current commitments;

(6) Previous experience with BOEM requirements and procedures, if any; and

(7) The level of work to be performed by the CVA.

(c) Individuals or organizations acting as CVAs must not function in any capacity that will create a conflict of interest, or the appearance of a conflict of interest.

(d) The verification must be conducted by or under the direct supervision of registered professional engineers.

(e) BOEM will approve or disapprove your CVA as part of its review of the COP or, when required, of your SAP or GAP.

(f) You must nominate a new CVA for BOEM approval if the previously approved CVA:

(1) Is no longer able to serve in a CVA capacity for the project; or

(2) No longer meets the requirements for a CVA set forth in this subpart.

§ 585.707 What are the CVA's primary duties for facility design review?

If you are required to use a CVA:

(a) The CVA must use good engineering judgment and practices in conducting an independent assessment of the design of the facility. The CVA must certify in the Facility Design Report to BOEM that the facility is designed to withstand the environmental and functional load conditions appropriate for the intended service life at the proposed location.

(b) The CVA must conduct an independent assessment of all proposed:

(1) Planning criteria;

(2) Operational requirements;

(3) Environmental loading data;

(4) Load determinations;

(5) Stress analyses;

(6) Material designations;

(7) Soil and foundation conditions;

(8) Safety factors; and

(9) Other pertinent parameters of the proposed design.

(c) For any floating facility, the CVA must ensure that any requirements of the U.S. Coast Guard for structural integrity and stability (e.g., verification of center of gravity), have been met. The CVA must also consider:

(1) Foundations, foundation pilings and templates, and anchoring systems; and

(2) Mooring or tethering systems.

§ 585.708 What are the CVA's or project engineer's primary duties for fabrication and installation review?

(a) The CVA or project engineer must do all of the following:

(1) Use good engineering judgment and practice in conducting an independent assessment of the fabrication and installation activities;

(2) Monitor the fabrication and installation of the facility as required by paragraph (b) of this section;

(3) Make periodic onsite inspections while fabrication is in progress and verify the items required by § 585.709;

(4) Make periodic onsite inspections while installation is in progress and satisfy the requirements of § 585.710; and

(5) Certify in a report that project components are fabricated and installed in accordance with accepted engineering practices; your approved COP, SAP, or GAP (as applicable); and the Fabrication and Installation Report.

(i) The report must also identify the location of all records pertaining to

fabrication and installation, as required in § 585.714(c); and

(ii) You may commence commercial operations or other approved activities 30 days after BOEM receives that certification report, unless BOEM notifies you within that time period of its objections to the certification report.

(b) To comply with paragraph (a)(5) of this section, the CVA or project engineer must monitor the fabrication and installation of the facility to ensure that it has been built and installed according to the Facility Design Report and Fabrication and Installation Report.

(1) If the CVA or project engineer finds that fabrication and installation procedures have been changed or design specifications have been modified, the CVA or project engineer must inform you; and

(2) If you accept the modifications, then you must also inform BOEM.

§ 585.709 When conducting onsite fabrication inspections, what must the CVA or project engineer verify?

(a) To comply with § 585.708(a)(3), the CVA or project engineer must make periodic onsite inspections while fabrication is in progress and must verify the following fabrication items, as appropriate:

(1) Quality control by lessee (or grant holder) and builder;

(2) Fabrication site facilities;

(3) Material quality and identification methods;

(4) Fabrication procedures specified in the Fabrication and Installation Report, and adherence to such procedures;

(5) Welder and welding procedure qualification and identification;

(6) Structural tolerances specified, and adherence to those tolerances;

(7) Nondestructive examination requirements and evaluation results of the specified examinations;

(8) Destructive testing requirements and results;

(9) Repair procedures;

(10) Installation of corrosion-protection systems and splash-zone protection;

(11) Erection procedures to ensure that overstressing of structural members does not occur;

(12) Alignment procedures;

(13) Dimensional check of the overall structure, including any turrets, turret-and-hull interfaces, any mooring line and chain and riser tensioning line segments; and

(14) Status of quality-control records at various stages of fabrication.

(b) For any floating facilities, the CVA or project engineer must ensure that any requirements of the U.S. Coast Guard for structural integrity and stability (e.g., verification of center of gravity) have been met. The CVA or project engineer must also consider:

(1) Foundations, foundation pilings and templates, and anchoring systems; and

(2) Mooring or tethering systems.

§ 585.710 When conducting onsite installation inspections, what must the CVA or project engineer do?

To comply with § 585.708(a)(4), the CVA or project engineer must make periodic onsite inspections while installation is in progress and must, as appropriate, verify, witness, survey, or check, the installation items required by this section.

(a) The CVA or project engineer must verify, as appropriate, all of the following:

(1) Loadout and initial flotation procedures;

(2) Towing operation procedures to the specified location, and review the towing records;

(3) Launching and uprighting activities;

(4) Submergence activities;

(5) Pile or anchor installations;

(6) Installation of mooring and tethering systems;

(7) Final deck and component installations; and

(8) Installation at the approved location according to the Facility Design Report and the Fabrication and Installation Report.

(b) For a fixed or floating facility, the CVA or project engineer must verify that proper procedures were used during the following:

(1) The loadout of the jacket, decks, piles, or structures from each fabrication site; and

(2) The actual installation of the facility or major modification and the related installation activities.

(c) For a floating facility, the CVA or project engineer must verify that proper procedures were used during the following:

(1) The loadout of the facility;

(2) The installation of foundation pilings and templates, and anchoring systems; and

(3) The installation of the mooring and tethering systems.

(d) The CVA or project engineer must conduct an onsite survey of the facility after transportation to the approved location.

(e) The CVA or project engineer must spot-check the equipment, procedures, and recordkeeping as necessary to determine compliance with the applicable documents incorporated by reference and the regulations under this part.

§ 585.711 [Reserved]

§ 585.712 What are the CVA's or project engineer's reporting requirements?

(a) The CVA or project engineer must prepare and submit to you and BOEM all reports required by this subpart. The CVA or project engineer must also submit interim reports to you and BOEM, as requested by the BOEM.

(b) For each report required by this subpart, the CVA or project engineer must submit one electronic copy and one paper copy of each final report to BOEM. In each report, the CVA or project engineer must:

(1) Give details of how, by whom, and when the CVA or project engineer activities were conducted;

(2) Describe the CVA's or project engineer's activities during the verification process;

(3) Summarize the CVA's or project engineer's findings; and

(4) Provide any additional comments that the CVA or project engineer deems necessary.

§ 585.713 What must I do after the CVA or project engineer confirms conformance with the Fabrication and Installation Report on my commercial lease?

After the CVA or project engineer files the certification report, you must notify BOEM within 10 business days after commencing commercial operations.

§ 585.714 What records relating to SAPs, COPs, and GAPs must I keep?

(a) Until BOEM releases your financial assurance under § 585.534, you must compile, retain, and make available to BOEM representatives, within the time specified by BOEM, all of the following:

(1) The as-built drawings;

(2) The design assumptions and analyses;

(3) A summary of the fabrication and installation examination records;

(4) The inspection results from the inspections and assessments required by §§ 585.820 through 585.825; and

(5) Records of repairs not covered in the inspection report submitted under § 585.824(b)(3).

(b) You must record and retain the original material test results of all primary structural materials during all stages of construction until BOEM releases your financial assurance under § 585.534. Primary material is material that, should it fail, would lead to a significant reduction in facility safety, structural reliability, or operating capabilities. Items such as steel brackets, deck stiffeners and secondary braces or beams would not generally be considered primary structural members (or materials).

(c) You must provide BOEM with the location of these records in the certification statement, as required in §§ 585.701(c), 585.703(b), and 585.708(a)(5)(i).

Subpart H—Environmental and Safety Management, Inspections, and Facility Assessments for Activities Conducted Under SAPs, COPs and GAPs

§ 585.800 How must I conduct my activities to comply with safety and environmental requirements?

(a) You must conduct all activities on your lease or grant under this part in a manner that conforms with your responsibilities in § 585.105(a), and using:

(1) Trained personnel; and

(2) Technologies, precautions, and techniques that will not cause undue harm or damage to natural resources,

including their physical, atmospheric, and biological components.

(b) You must certify compliance with those terms and conditions identified in your approved SAP, COP, or GAP, as required under § 585.615(c), § 585.633(b), or § 585.653(c).

§ 585.801 How must I conduct my approved activities to protect marine mammals, threatened and endangered species, and designated critical habitat?

(a) You must not conduct any activity under your lease or grant that may affect threatened or endangered species or that may affect designated critical habitat of such species until the appropriate level of consultation is conducted, as required under the ESA, as amended (16 U.S.C. 1531 *et seq.*), to ensure that your actions are not likely to jeopardize a threatened or endangered species and are not likely to destroy or adversely modify designated critical habitat.

(b) You must not conduct any activity under your lease or grant that may result in an incidental taking of marine mammals until the appropriate authorization has been issued under the Marine Mammal Protection Act of 1972 (MMPA) as amended (16 U.S.C. 1361 *et seq.*).

(c) If there is reason to believe that a threatened or endangered species may be present while you conduct your BOEM approved activities or may be affected by the direct or indirect effects of your actions:

(1) You must notify us that endangered or threatened species may be present in the vicinity of the lease or grant or may be affected by your actions; and

(2) We will consult with appropriate State and Federal fish and wildlife agencies and, after consultation, shall identify whether, and under what conditions, you may proceed.

(d) If there is reason to believe that designated critical habitat of a threatened or endangered species may be affected by the direct or indirect effects of your BOEM approved activities:

(1) You must notify us that designated critical habitat of a threatened or endangered species in the vicinity of the lease or grant may be affected by your actions; and

(2) We will consult with appropriate State and Federal fish and wildlife agencies and, after consultation, shall identify whether, and under what conditions, you may proceed.

(e) If there is reason to believe that marine mammals may be incidentally taken as a result of your proposed activities:

(1) You must agree to secure an authorization from National Oceanic and Atmospheric Administration (NOAA) or the U.S. Fish and Wildlife Service (FWS) for incidental taking, including taking by harassment, that may result from your actions; and

(2) You must comply with all measures required by the NOAA or FWS, including measures to affect the least practicable impact on such species and its habitat and to ensure no immitigable adverse impact on the availability of the species for subsistence use.

(f) Submit to us:

(1) Measures designed to avoid or minimize adverse effects and any potential incidental take of the endangered or threatened species or marine mammals;

(2) Measures designed to avoid likely adverse modification or destruction of designated critical habitat of such endangered or threatened species; and

(3) Your agreement to monitor for the incidental take of the species and adverse effects on the critical habitat, and provide the results of the monitoring to BOEM as required; and

(4) Your agreement to perform any relevant terms and conditions of the Incidental Take Statement that may result from the ESA consultation.

(5) Your agreement to perform any relevant mitigation measures under an MMPA incidental take authorization.

§ 585.802 What must I do if I discover a potential archaeological resource while conducting my approved activities?

(a) If you, your subcontractors, or any agent acting on your behalf discovers a potential archaeological resource while conducting construction activities, or any other activity related to your project, you must:

(1) Immediately halt all seafloor-disturbing activities within the area of the discovery;

(2) Notify BOEM of the discovery within 72 hours; and

(3) Keep the location of the discovery confidential and not take any action that may adversely affect the archaeological resource until we have made an evaluation and instructed you on how to proceed.

(b) We may require you to conduct additional investigations to determine if the resource is eligible for listing in the National Register of Historic Places under 36 CFR 60.4. We will do this if:

(1) The site has been impacted by your project activities; or

(2) Impacts to the site or to the area of potential effect cannot be avoided.

(c) If investigations under paragraph (b) of this section indicate that the resource is potentially eligible for listing in the National Register of Historic Places, we will tell you how to protect the resource, or how to mitigate adverse effects to the site.

(d) If we incur costs in protecting the resource, under section 110(g) of the NHPA, we may charge you reasonable costs for carrying out preservation responsibilities under the OCS Lands Act.

§ 585.803 How must I conduct my approved activities to protect essential fish habitats identified and described under the Magnuson-Stevens Fishery Conservation and Management Act?

(a) If, during the conduct of your approved activities, BOEM finds that essential fish habitat or habitat areas of particular concern may be adversely affected by your activities, BOEM must consult with National Marine Fisheries Service.

(b) Any conservation recommendations adopted by BOEM to avoid or minimize adverse affects on Essential Fish Habitat will be incorporated as terms and conditions in the lease and must be adhered to by the applicant. BOEM may require additional surveys to define boundaries and avoidance distances.

(c) If required, BOEM will specify the survey methods and instrumentations for conducting the biological survey and will specify the contents of the biological report.

§§ 585.804–585.809 [Reserved]

SAFETY MANAGEMENT SYSTEMS

§ 585.810 What must I include in my Safety Management System?

You must submit a description of the Safety Management System you will use with your COP (provided under § 585.627(d)) and, when required by this part, your SAP (as provided in § 585.614(b)) or GAP (as provided in § 585.651). You must describe:

(a) How you will ensure the safety of personnel or anyone on or near your facilities;

(b) Remote monitoring, control, and shut down capabilities;

(c) Emergency response procedures;

(d) Fire suppression equipment, if needed;

(e) How and when you will test your Safety Management System; and

(f) How you will ensure personnel who operate your facilities are properly trained.

§ 585.811 When must I follow my Safety Management System?

Your Safety Management System must be fully functional when you begin activities described in your approved COP, SAP, or GAP. You must conduct all activities described in your approved COP, SAP, or GAP in accordance with the Safety Management System you described, as required by § 585.810.

§ 585.812 [Reserved]

MAINTENANCE AND SHUTDOWNS

§ 585.813 When do I have to report removing equipment from service?

(a) The removal of any equipment from service may result in BOEM applying remedies, as provided in this part, when such equipment is necessary for implementing your approved plan. Such remedies may include an order from BOEM requiring you to replace or remove such equipment or facilities.

(b)(1) You must report within 24 hours when equipment necessary for implementing your approved plan is removed from service for more than 12

hours. If you provide an oral notification, you must submit a written confirmation of this notice within 3 business days, as required by § 585.105(c);

(2) You do not have to report removing equipment necessary for implementing your plan if the removal is part of planned maintenance or repair activities; and

(3) You must notify BOEM when you return the equipment to service.

§ 585.814 [Reserved]

EQUIPMENT FAILURE AND ADVERSE ENVIRONMENTAL EFFECTS

§ 585.815 What must I do if I have facility damage or an equipment failure?

(a) If you have facility damage or the failure of a pipeline, cable, or other equipment necessary for you to implement your approved plan, you must make repairs as soon as practicable. If you have a major repair, you must submit a report of the repairs to BOEM, as required in § 585.711.

(b) If you are required to report any facility damage or failure under § 585.831, BOEM may require you to revise your SAP, COP, or GAP to describe how you will address the facility damage or failure as required by § 585.634 (COP), § 585.617 (SAP), § 585.655 (GAP). You must submit a report of the repairs to BOEM, as required in § 585.703.

(c) BOEM may require that you analyze cable, pipeline, or facility damage or failure to determine the cause. If requested by BOEM, you must submit a comprehensive written report of the failure or damage to BOEM as soon as available.

§ 585.816 What must I do if environmental or other conditions adversely affect a cable, pipeline, or facility?

If environmental or other conditions adversely affect a cable, pipeline, or facility so as to endanger the safety or the environment, you must:

(a) Submit a plan of corrective action to BOEM within 30 days of the discovery of the adverse effect.

(b) Take remedial action as described in your corrective action plan.

(c) Submit to the BOEM a report of the remedial action taken within 30 days after completion.

§§ 585.817–585.819 [Reserved]

INSPECTIONS AND ASSESSMENT

§ 585.820 Will BOEM conduct inspections?

BOEM will inspect OCS facilities and any vessels engaged in activities authorized under this part. We conduct these inspections:

(a) To verify that you are conducting activities in compliance with subsection 8(p) of the OCS Lands Act; the regulations in this part; the terms, conditions, and stipulations of your lease or grant; approved plans; and other applicable laws and regulations.

(b) To determine whether proper safety equipment has been installed and is operating properly according to your Safety Management System, as required in § 585.810.

§ 585.821 Will BOEM conduct scheduled and unscheduled inspections?

BOEM will conduct both scheduled and unscheduled inspections.

§ 585.822 What must I do when BOEM conducts an inspection?

(a) When BOEM conducts an inspection, you must:

(1) Provide access to all facilities on your lease (including your project easement) or grant; and

(2) Make the following available for BOEM to inspect:

(i) The area covered under a lease, ROW grant, or RUE grant;

(ii) All improvements, structures, and fixtures on these areas; and

(iii) All records of design, construction, operation, maintenance, repairs, or investigations on or related to the area.

(b) You must retain these records in paragraph (a)(2)(iii) of this section until BOEM releases your financial assurance under § 585.534 and provide them to BOEM upon request, within the time period specified by BOEM.

(c) You must demonstrate to the inspector how you are in compliance with your Safety Management System.

§ 585.823 Will BOEM reimburse me for my expenses related to inspections?

Upon request, BOEM will reimburse you for food, quarters, and transportation that you provide for our representatives while they inspect your lease or grant facilities and associated activities. You must send us your reimbursement request within 90 days of the inspection.

§ 585.824 How must I conduct self-inspections?

(a) You must develop a comprehensive annual self-inspection plan covering all of your facilities. You must keep this plan wherever you keep your records and make it available to BOEM inspectors upon request. Your plan must specify:

(1) The type, extent, and frequency of in-place inspections that you will conduct for both the above-water and the below-water structures of all facilities and pertinent components of the mooring systems for any floating facilities; and

(2) How you are monitoring the corrosion protection for both the above-water and below-water structures.

(b) You must submit a report annually to us no later than November 1 that must include:

(1) A list of facilities inspected in the preceding 12 months;

(2) The type of inspection employed, (*i.e.*, visual, magnetic particle, ultrasonic testing); and

(3) A summary of the inspection indicating what repairs, if any, were needed and the overall structural condition of the facility.

§ 585.825 When must I assess my facilities?

(a) You must perform an assessment of the structure, when needed, based on the platform assessment initiators listed in sections 17.2.1–17.2.5 of API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design (as incorporated by reference in § 585.115).

(b) You must initiate mitigation actions for structures that do not pass the assessment process of API RP 2A–WSD.

(c) You must perform other assessments as required by BOEM.

§§ 585.826–585.829 [Reserved]

INCIDENT REPORTING AND INVESTIGATION

§ 585.830 What are my incident reporting requirements?

(a) You must report all incidents listed in § 585.831 to BOEM, according to the reporting requirements for these incidents in §§ 585.832 and 585.833.

(b) These reporting requirements apply to incidents that occur on the area covered by your lease or grant under this part and that are related to activities resulting from the exercise of your rights under your lease or grant under this part.

(c) Nothing in this subpart relieves you from providing notices and reports of incidents that may be required by other regulatory agencies.

(d) You must report all spills of oil or other liquid pollutants in accordance with 30 CFR 254.46.

§ 585.831 What incidents must I report, and when must I report them?

(a) You must report the following incidents to us immediately via oral communication, and provide a written follow-up report (paper copy or electronically transmitted) within 15 business days after the incident:

(1) Fatalities;

(2) Incidents that require the evacuation of person(s) from the facility to shore or to another offshore facility;

(3) Fires and explosions;

(4) Collisions that result in property or equipment damage greater than $25,000 (Collision means the act of a moving vessel (including an aircraft) striking another vessel, or striking a stationary vessel or object. Property or equipment damage means the cost of labor and material to restore all affected items to their condition before the damage, including, but not limited to, the OCS facility, a vessel, a helicopter, or the equipment. It does not include the cost of salvage, cleaning, dry docking, or demurrage);

(5) Incidents involving structural damage to an OCS facility that is severe enough so that activities on the facility cannot continue until repairs are made;

(6) Incidents involving crane or personnel/material handling activities, if they result in a fatality, injury, structural damage, or significant environmental damage;

(7) Incidents that damage or disable safety systems or equipment (including firefighting systems);

(8) Other incidents resulting in property or equipment damage greater than $25,000; and

(9) Any other incidents involving significant environmental damage, or harm.

(b) You must provide a written report of the following incidents to us within 15 days after the incident:

(1) Any injuries that result in the injured person not being able to return to work or to all of their normal duties the day after the injury occurred; and

(2) All incidents that require personnel on the facility to muster for evacuation for reasons not related to weather or drills.

§ 585.832 How do I report incidents requiring immediate notification?

For an incident requiring immediate notification under § 585.831(a), you must notify BOEM verbally after aiding the injured and stabilizing the situation. Your verbal communication must provide the following information:

(a) Date and time of occurrence;

(b) Identification and contact information for the lessee, grant holder, or operator;

(c) Contractor, and contractor representative's name and telephone number (if a contractor is involved in the incident or injury/fatality);

(d) Lease number, OCS area, and block;

(e) Platform/facility name and number, or cable or pipeline segment number;

(f) Type of incident or injury/fatality;

(g) Activity at time of incident; and

(h) Description of the incident, damage, or injury/fatality.

§ 585.833 What are the reporting requirements for incidents requiring written notification?

(a) For any incident covered under § 585.831, you must submit a written report within 15 days after the incident to BOEM. The report must contain the following information:

(1) Date and time of occurrence;

(2) Identification and contact information for each lessee, grant holder, or operator;

(3) Name and telephone number of the contractor and the contractor's representative, if a contractor is involved in the incident or injury;

(4) Lease number, OCS area, and block;

(5) Platform/facility name and number, or cable or pipeline segment number;

(6) Type of incident or injury;

(7) Activity at time of incident;

(8) Description of incident, damage, or injury (including days away from work, restricted work, or job transfer), and any corrective action taken; and

(9) Property or equipment damage estimate (in U.S. dollars).

(b) You may submit a report or form prepared for another agency in lieu of the written report required by paragraph (a) of this section if the report or form contains all required information.

(c) BOEM may require you to submit additional information about an incident on a case-by-case basis.

Subpart I—Decommissioning

DECOMMISSIONING OBLIGATIONS AND REQUIREMENTS

§ 585.900 Who must meet the decommissioning obligations in this subpart?

(a) Lessees are jointly and severally responsible for meeting decommissioning obligations for facilities on their leases, including all obstructions, as the obligations accrue and until each obligation is met.

(b) Grant holders are jointly and severally liable for meeting decommissioning obligations for facilities on their grant, including all obstructions, as the obligations accrue and until each obligation is met.

§ 585.901 When do I accrue decommissioning obligations?

You accrue decommissioning obligations when you are or become a lessee or grant holder, and you either install,

construct, or acquire by a BOEM-approved assignment a facility, cable, or pipeline, or you create an obstruction to other uses of the OCS.

§ 585.902 What are the general requirements for decommissioning for facilities authorized under my SAP, COP, or GAP?

(a) Except as otherwise authorized by BOEM under § 585.909, within 2 years following termination of a lease or grant, you must:

(1) Remove or decommission all facilities, projects, cables, pipelines, and obstructions;

(2) Clear the seafloor of all obstructions created by activities on your lease, including your project easement, or grant, as required by the BOEM.

(b) Before decommissioning the facilities under your SAP, COP, or GAP, you must submit a decommissioning application and receive approval from the BOEM.

(c) The approval of the decommissioning concept in the SAP, COP, or GAP is not an approval of a decommissioning application. However, you may submit your complete decommissioning application simultaneously with the SAP, COP, or GAP so that it may undergo appropriate technical and regulatory reviews at that time.

(d) Following approval of your decommissioning application, you must submit a decommissioning notice under § 585.908 to BOEM at least 60 days before commencing decommissioning activities.

(e) If you, your subcontractors, or any agent acting on your behalf discover any archaeological resource while conducting decommissioning activities, you must immediately halt bottom-disturbing activities within 1,000 feet of the discovery and report the discovery to us within 72 hours. We will inform you how to conduct investigations to determine if the resource is significant and how to protect it. You, your subcontractors, or any agent acting on your behalf must keep the location of the discovery confidential and must not take any action that may adversely affect the archaeological resource until we have made an evaluation and told you how to proceed.

(f) Provide BOEM with documentation of any coordination efforts you have made with the affected States, local, and Tribal governments.

§ 585.903 What are the requirements for decommissioning FERC-licensed hydrokinetic facilities?

You must comply with the decommissioning requirements in your BOEM-issued lease. If you fail to comply with the decommissioning requirements of your lease then:

(a) BOEM may call for the forfeiture of your bond or other financial assurance;

(b) You remain liable for removal or disposal costs and responsible for accidents or damages that might result from such failure; and

(c) BOEM may take enforcement action under § 585.400 of this part.

§ 585.904 Can I request a departure from the decommissioning requirements?

You may request a departure from the decommissioning requirements under § 585.103.

DECOMMISSIONING APPLICATIONS

§ 585.905 When must I submit my decommissioning application?

You must submit your decommissioning application upon the earliest of the following dates:

(a) 2 years before the expiration of your lease.

(b) 90 days after completion of your commercial activities on a commercial lease.

(c) 90 days after completion of your approved activities under a limited lease on a ROW grant or RUE grant.

(d) 90 days after cancellation, relinquishment, or other termination of your lease or grant.

§ 585.906 What must my decommissioning application include?

You must provide one paper copy and one electronic copy of the application. Include the following information in the application, as applicable.

(a) Identification of the applicant including:

(1) Lease operator, ROW grant holder, or RUE grant holder;

(2) Address;

(3) Contact person and telephone number; and

(4) Shore base.

(b) Identification and description of the facilities, cables, or pipelines you plan to remove or propose to leave in place, as provided in § 585.909.

(c) A proposed decommissioning schedule for your lease, ROW grant, or RUE grant, including the expiration or relinquishment date and proposed month and year of removal.

(d) A description of the removal methods and procedures, including the types of equipment, vessels, and moorings (*i.e.*, anchors, chains, lines, *etc.*) you will use.

(e) A description of your site clearance activities.

(f) Your plans for transportation and disposal (including as an artificial reef) or salvage of the removed facilities, cables, or pipelines and any required approvals.

(g) A description of those resources, conditions, and activities that could be affected by or could affect your proposed decommissioning activities. The description must be as detailed as necessary to assist BOEM in complying with the NEPA and other relevant Federal laws.

(h) The results of any recent biological surveys conducted in the vicinity of the structure and recent observations of turtles or marine mammals at the structure site.

(i) Mitigation measures you will use to protect archaeological and sensitive biological features during removal activities.

(j) A description of measures you will take to prevent unauthorized discharge of pollutants, including marine trash and debris, into the offshore waters.

(k) A statement of whether or not you will use divers to survey the area after removal to determine any effects on marine life.

§ 585.907 How will BOEM process my decommissioning application?

(a) Based upon your inclusion of all the information required by § 585.906, BOEM will compare your decommissioning application with the decommissioning general concept in your approved SAP, COP, or GAP to determine what technical and environmental reviews are needed.

(b) You will likely have to revise your SAP, COP, or GAP, and BOEM will begin the appropriate NEPA analysis and other regulatory reviews as required, if BOEM determines that your decommissioning application would:

(1) Result in a significant change in the impacts previously identified and evaluated in your SAP, COP, or GAP;

(2) Require any additional Federal permits; or

(3) Propose activities not previously identified and evaluated in your SAP, COP, or GAP.

(c) During the review process, we may request additional information if we determine that the information provided is not sufficient to complete the review and approval process.

(d) Upon completion of the technical and environmental reviews, we may approve, approve with conditions, or disapprove your decommissioning application.

(e) If BOEM disapproves your decommissioning application, you must resubmit your application to address the concerns identified by BOEM.

§ 585.908 What must I include in my decommissioning notice?

(a) The decommissioning notice is distinct from your decommissioning application and may only be submitted following approval of your decommissioning application, as described in §§ 585.905 through 585.907. You must submit a decommissioning notice at least 60 days before you plan to begin decommissioning activities.

(b) Your decommissioning notice must include:

(1) A description of any changes to the approved removal methods and procedures in your approved decommissioning application, including changes to the types of vessels and equipment you will use; and

(2) An updated decommissioning schedule.

(c) We will review your decommissioning notice and may require you to resubmit a decommissioning application if BOEM determines that your decommissioning activities would:

(1) Result in a significant change in the impacts previously identified and evaluated;

(2) Require any additional Federal permits; or

(3) Propose activities not previously identified and evaluated.

FACILITY REMOVAL

§ 585.909 When may BOEM authorize facilities to remain in place following termination of a lease or grant?

(a) In your decommissioning application, you may request that certain facilities authorized in your lease or grant remain in place for other activities authorized in this part, elsewhere in this subchapter, or by other applicable Federal laws.

(b) BOEM may approve such requests on a case-by-case basis considering the following:

(1) Potential impacts to the marine environment;

(2) Competing uses of the OCS;

(3) Impacts on marine safety and National defense;

(4) Maintenance of adequate financial assurance; and

(5) Other factors determined by the Director.

(c) Except as provided in paragraph (d) of this section, if BOEM authorizes facilities to remain in place, the former lessee or grantee under this part remains jointly and severally liable for decommissioning the facility unless satisfactory evidence is provided to BOEM showing that another party has assumed that responsibility and has secured adequate financial assurances.

(d) In your decommissioning application, you may request that certain facilities authorized in your lease or grant be converted to an artificial reef or otherwise toppled in place. BOEM will evaluate all such requests.

§ 585.910 What must I do when I remove my facility?

(a) You must remove all facilities to a depth of 15 feet below the mudline, unless otherwise authorized by BOEM.

(b) Within 60 days after you remove a facility, you must verify to BOEM that you have cleared the site.

§ 585.911 [Reserved]

DECOMMISSIONING REPORT

§ 585.912 After I remove a facility, cable, or pipeline, what information must I submit?

Within 60 days after you remove a facility, cable, or pipeline, you must submit a written report to BOEM that includes the following:

(a) A summary of the removal activities, including the date they were completed;

(b) A description of any mitigation measures you took; and

(c) If you used explosives, a statement signed by your authorized representative that certifies that the types and amount of explosives you used in removing the facility were consistent with those in the approved decommissioning application.

COMPLIANCE WITH AN APPROVED DECOMMISSIONING APPLICATION

§ 585.913 What happens if I fail to comply with my approved decommissioning application?

If you fail to comply with your approved decommissioning plan or application:

(a) BOEM may call for the forfeiture of your bond or other financial assurance;

(b) You remain liable for removal or disposal costs and responsible for accidents or damages that might result from such failure; and

(c) BOEM may take enforcement action under § 585.400.

Subpart J—Rights of Use and Easement for Energy- and Marine-Related Activities Using Existing OCS Facilities

REGULATED ACTIVITIES

§ 585.1000 What activities does this subpart regulate?

(a) This subpart provides the general provisions for authorizing and regulating activities that use (or propose to use) an existing OCS facility for energy- or marine-related purposes, that are not otherwise authorized under any other part of this subchapter

or any other applicable Federal statute. Activities authorized under any other part of this subchapter or under any other Federal law that use (or propose to use) an existing OCS facility are not subject to this subpart.

(b) BOEM will issue an Alternate Use RUE for activities authorized under this subpart.

(c) At the discretion of the Director, an Alternate Use RUE may:

(1) Permit alternate use activities to occur at an existing facility that is currently in use under an approved OCS lease; or

(2) Limit alternate use activities at the existing facility until after previously authorized activities at the facility have ceased and the OCS lease terminates.

§§ 585.1001–585.1003 [Reserved]

REQUESTING AN ALTERNATE USE RUE

§ 585.1004 What must I do before I request an Alternate Use RUE?

If you are not the owner of the existing facility on the OCS and the lessee of the area in which the facility is located, you must contact the lessee and owner of the facility and reach a preliminary agreement as to the proposed activity for the use of the existing facility.

§ 585.1005 How do I request an Alternate Use RUE?

To request an Alternate Use RUE, you must submit to BOEM all of the following:

(a) The name, address, e-mail address, and phone number of an authorized representative.

(b) A summary of the proposed activities for the use of an existing OCS facility, including:

(1) The type of activities that would involve the use of the existing OCS facility;

(2) A description of the existing OCS facility, including a map providing its location on the lease block;

(3) The names of the owner of the existing OCS facility, the operator, the lessee, and any owner of operating rights on the lease at which the facility is located;

(4) A description of additional structures or equipment that will be required to be located on or in the vicinity of the existing OCS facility in connection with the proposed activities;

(5) A statement indicating whether any of the proposed activities are intended to occur before existing activities on the OCS facility have ceased; and

(6) A statement describing how existing activities at the OCS facility will be affected if proposed activities are to occur at the same time as existing activities at the OCS facility.

(c) A statement affirming that the proposed activities sought to be approved under this subpart are not otherwise authorized by other provisions in this subchapter or any other Federal law.

(d) Evidence that you meet the requirements of § 585.106, as required by § 585.107.

(e) The signatures of the applicant, the owner of the existing OCS facility, and the lessee of the area in which the existing facility is located.

§ 585.1006 How will BOEM decide whether to issue an Alternate Use RUE?

(a) We will consider requests for an Alternate Use RUE on a case-by-case basis. In considering such requests, we will consult with relevant Federal agencies and evaluate whether the proposed activities involving the use of an existing OCS facility can be conducted in a manner that:

(1) Ensures safety and minimizes adverse effects to the coastal and marine environments, including their physical, atmospheric, and biological components, to the extent practicable;

(2) Does not inhibit or restrain orderly development of OCS mineral or energy resources; and

(3) Avoids 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), or property (including sites, structures, or objects of historical or archaeological significance);

(4) Is otherwise consistent with subsection 8(p) of the OCS Lands Act; and

(5) BOEM can effectively regulate.

(b) Based on the evaluation that we perform under paragraph (a) of this section, the BOEM may authorize or reject, or authorize with modifications or stipulations, the proposed activity.

§ 585.1007 What process will BOEM use for competitively offering an Alternate Use RUE?

(a) An Alternate Use RUE must be issued on a competitive basis unless BOEM determines, after public notice of the proposed Alternate Use RUE, that there is no competitive interest.

(b) We will issue a public notice in the FEDERAL REGISTER to determine if there is competitive interest in using the proposed facility for alternate use activities. BOEM will specify a time period for members of the public to express competitive interest.

(c) If we receive indications of competitive interest within the published timeframe, we will proceed with a competitive offering. As part of such competitive offering, each competing applicant must submit a description of the types of activities proposed for the existing facility, as well as satisfactory evidence that the competing applicant qualifies to hold a lease or grant on the OCS, as required in §§ 585.106 and 585.107, by a date we specify. We may request additional information from competing applicants, as necessary, to adequately evaluate the competing proposals.

(d) We will evaluate all competing proposals to determine whether:

(1) The proposed activities are compatible with existing activities at the facility; and

(2) We have the expertise and resources available to regulate the activities effectively.

(e) We will evaluate all proposals under the requirements of NEPA, CZMA, and other applicable laws.

(f) Following our evaluation, we will select one or more acceptable proposals for activities involving the alternate use of an existing OCS facility, notify the competing applicants, and submit each acceptable proposal to the lessee and owner of the existing OCS facility. If the lessee and owner of the facility agree to accept a proposal, we will proceed to issue an Alternate Use RUE. If the lessee and owner of the facility are unwilling to accept any of the proposals that we deem acceptable, we will not issue an Alternate Use RUE.

§§ 585.1008–585.1009 [Reserved]

ALTERNATE USE RUE ADMINISTRATION

§ 585.1010 How long may I conduct activities under an Alternate Use RUE?

(a) We will establish on a case-by-case basis, and set forth in the Alternate Use RUE, the length of time for which you are authorized to conduct activities approved in your Alternate Use RUE instrument.

(b) In establishing this term, BOEM will consider the size and scale of the proposed alternate use activities, the type of alternate use activities, and any other relevant considerations.

(c) BOEM may authorize renewal of Alternate Use RUEs at its discretion.

§ 585.1011 What payments are required for an Alternate Use RUE?

We will establish rental or other payments for an Alternate Use RUE on a case-by-case basis, as set forth in the Alternate Use RUE grant, depending on our assessment of the following factors:

(a) The effect on the original OCS Lands Act approved activity;

(b) The size and scale of the proposed alternate use activities;

(c) The income, if any, expected to be generated from the proposed alternate use activities; and

(d) The type of alternate use activities.

§ 585.1012 What financial assurance is required for an Alternate Use RUE?

(a) The holder of an Alternate Use RUE will be required to secure financial assurances in an amount determined by BOEM that is sufficient to cover all obligations under the Alternate Use RUE, including decommissioning obligations, and must retain such financial assurance amounts until all obligations have been fulfilled, as determined by BOEM.

(b) We may revise financial assurance amounts, as necessary, to ensure that there is sufficient financial assurance to secure all obligations under the Alternate Use RUE.

(c) We may reduce the amount of the financial assurance that you must retain if it is not necessary to cover existing obligations under the Alternate Use RUE.

§ 585.1013 Is an Alternate Use RUE assignable?

(a) BOEM may authorize assignment of an Alternate Use RUE.

(b) To request assignment of an Alternate Use RUE, you must submit a written request for assignment that includes the following information:

(1) BOEM-assigned Alternate Use RUE number;

(2) The names of both the assignor and the assignee, if applicable;

(3) The names and telephone numbers of the contacts for both the assignor and the assignee;

(4) The names, titles, and signatures of the authorizing officials for both the assignor and the assignee;

(5) A statement affirming that the owner of the existing OCS facility and lessee of the lease in which the facility is located approve of the proposed assignment and assignee;

(6) A statement that the assignee agrees to comply with and to be bound by the terms and conditions of the Alternate Use RUE;

(7) Evidence required by § 585.107 that the assignee satisfies the requirements of § 585.106; and

(8) A statement on how the assignee will comply with the financial assurance requirements set forth in the Alternate Use RUE.

(c) The assignment takes effect on the date we approve your request.

(d) The assignor is liable for all obligations that accrue under an Alternate Use RUE before the date we approve your assignment request. An assignment approval by BOEM does not relieve the assignor of liability for accrued obligations that the assignee, or a subsequent assignee, fails to perform.

(e) The assignee and each subsequent assignee are liable for all obligations that accrue under an Alternate Use RUE after the date we approve the assignment request.

§ 585.1014 When will BOEM suspend an Alternate Use RUE?

(a) BOEM may suspend an Alternate Use RUE if:

(1) Necessary to comply with judicial decrees;

(2) Continued activities pursuant to the Alternate Use RUE pose an imminent threat of serious or irreparable harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(3) The suspension is necessary for reasons of National security or defense; or

(4) We have suspended or temporarily prohibited operation of the existing OCS facility that is subject to the Alternate Use RUE, and have determined that continued activities under the Alternate Use RUE are unsafe or cause undue interference with the operation of the original OCS Lands Act approved activity.

(b) A suspension will extend the term of your Alternate Use RUE grant for the period of the suspension.

§ 585.1015 How do I relinquish an Alternate Use RUE?

(a) You may voluntarily surrender an Alternate Use RUE by submitting a written request to us that includes the following:

(1) The name, address, e-mail address, and phone number of an authorized representative;

(2) The reason you are requesting relinquishment of the Alternate Use RUE;

(3) BOEM-assigned Alternate Use RUE number;

(4) The name of the associated OCS facility, its owner, and the lessee for the lease in which the OCS facility is located;

(5) The name, title, and signature of your authorizing official (which must match exactly the name, title, and signature in the BOEM qualification records); and

(6) A statement that you will adhere to the decommissioning requirements in the Alternate Use RUE.

(b) We will not approve your relinquishment request until you have paid

all outstanding rentals (or other payments) and fines.

(c) The relinquishment takes effect on the date we approve your request.

§ 585.1016 When will an Alternate Use RUE be cancelled?

The Secretary may cancel an Alternate Use RUE if it is determined, after notice and opportunity to be heard:

(a) You no longer qualify to hold an Alternate Use RUE;

(b) You failed to provide any additional financial assurance required by BOEM, replace or provide additional coverage for a de-valued bond, or replace a lapsed or forfeited bond within the prescribed time period;

(c) Continued activity under the Alternate Use RUE is likely to cause serious harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance;

(d) Continued activity under the Alternate Use RUE is determined to be adversely impacting the original OCS Lands Act approved activities on the existing OCS facility;

(e) You failed to comply with any of the terms and conditions of your approved Alternate Use RUE or your approved plan; or

(f) You otherwise failed to comply with applicable laws or regulations.

§ 585.1017 [Reserved]

DECOMMISSIONING AN ALTERNATE USE RUE

§ 585.1018 Who is responsible for decommissioning an OCS facility subject to an Alternate Use RUE?

(a) The holder of an Alternate Use RUE is responsible for all decommissioning obligations that accrue following the issuance of the Alternate Use RUE and which pertain to the Alternate Use RUE.

(b) The lessee under the lease originally issued under 30 CFR part 250 will remain responsible for decommissioning obligations that accrued before issuance of the Alternate Use RUE, as well as for decommissioning obligations that accrue following issuance of the Alternate Use RUE to the extent associated with continued activities authorized under other parts of this title.

§ 585.1019 What are the decommissioning requirements for an Alternate Use RUE?

(a) Decommissioning requirements will be determined by BOEM on a case-by-case basis, and will be included in the terms of each Alternate Use RUE.

(b) Decommissioning activities must be completed within 1 year of termination of the Alternate Use RUE.

(c) If you fail to satisfy all decommissioning requirements within the prescribed time period, we will call for the forfeiture of your bond or other financial guarantee, and you will remain liable for all accidents or damages that might result from such failure.

SUBCHAPTER C—APPEALS

PART 590—APPEAL PROCEDURES

Subpart A—Offshore Minerals Management Appeal Procedures

Sec.
590.1 What is the purpose of this subpart?
590.2 Who may appeal?
590.3 What is the time limit for filing an appeal?
590.4 How do I file an appeal?
590.5 Can I obtain an extension for filing my Notice of Appeal?
590.6 Are informal resolutions permitted?
590.7 Do I have to comply with the decision or order while my appeal is pending?
590.8 How do I exhaust my administrative remedies?

Subpart B [Reserved]

AUTHORITY: 5 U.S.C. 301 *et seq.;* 31 U.S.C. 9701; 43 U.S.C. 1334.

SOURCE: 76 FR 64623, Oct. 18, 2011, unless otherwise noted.

Subpart A—Offshore Minerals Management Appeal Procedures

§ 590.1 What is the purpose of this subpart?

The purpose of this subpart is to explain the procedures for appeals of Bureau of Ocean Energy Management (BOEM) Offshore Minerals Management (OMM) decisions and orders issued under subchapter C.

§ 590.2 Who may appeal?

If you are adversely affected by an OMM official's final decision or order issued under 30 CFR chapter V, subchapter C, you may appeal that decision or order to the Interior Board of Land Appeals (IBLA). Your appeal must conform with the procedures found in this subpart and 43 CFR part 4, subpart E. A request for reconsideration of a BOEM decision concerning a lease bid, authorized in 30 CFR parts 556.47(e)(3), 581.21(a)(1), or 585.118(c), is not subject to the procedures found in this part.

§ 590.3 What is the time limit for filing an appeal?

You must file your appeal within 60 days after you receive OMM's final decision or order. The 60-day time period applies rather than the time period provided in 43 CFR 4.411(a). A decision or order is received on the date you sign a receipt confirming delivery or, if there is no receipt, the date otherwise documented.

§ 590.4 How do I file an appeal?

For your appeal to be filed, BOEM must receive all of the following within 60 days after you receive the decision or order:

(a) A written Notice of Appeal together with a copy of the decision or order you are appealing in the office of the OEMM officer that issued the decision or order. You cannot extend the 60-day period for that office to receive your Notice of Appeal; and

(b) A nonrefundable processing fee of $150 paid with the Notice of Appeal.

(1) You must pay electronically through the *Fees for Services* page on the BOEM Web site at *http://www.boem.gov*, and you must include a copy of the *Pay.gov* confirmation receipt page with your Notice of Appeal.

(2) You cannot extend the 60-day period for payment of the processing fee.

[76 FR 64623, Oct. 18, 2011, as amended at 79 FR 21626, Apr. 17, 2014]

§ 590.5 Can I obtain an extension for filing my Notice of Appeal?

You cannot obtain an extension of time to file the Notice of Appeal. See 43 CFR 4.411(c).

§ 590.6 Are informal resolutions permitted?

(a) You may seek informal resolution with the issuing officer's next level supervisor during the 60-day period established in § 590.3.

(b) Nothing in this subpart precludes resolution by settlement of any appeal or matter pending in the administrative process after the 60-day period established in § 590.3.

§ 590.7 Do I have to comply with the decision or order while my appeal is pending?

(a) The decision or order is effective during the 60-day period for filing an appeal under § 590.3 unless:

(1) OMM notifies you that the decision or order, or some portion of it, is suspended during this period because there is no likelihood of immediate and irreparable harm to human life, the environment, any mineral deposit, or property; or

(2) You post a surety bond under 30 CFR 550.1409 pending the appeal challenging an order to pay a civil penalty.

(b) This section applies rather than 43 CFR 4.21(a) for appeals of OMM orders.

(c) After you file your appeal, IBLA may grant a stay of a decision or order under 43 CFR 4.21(b); however, a decision or order remains in effect until IBLA grants your request for a stay of the decision or order under appeal.

§ 590.8 How do I exhaust my administrative remedies?

(a) If you receive a decision or order issued under chapter V, subchapter C, you must appeal that decision or order to IBLA under 43 CFR part 4, subpart E, to exhaust administrative remedies.

(b) This section does not apply if the Assistant Secretary for Land and Minerals Management or the IBLA makes a decision or order immediately effective notwithstanding an appeal.

Subpart B [Reserved]

PARTS 591–599 [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.

Table of CFR Titles and Chapters
Alphabetical List of Agencies Appearing in the CFR
List of CFR Sections Affected

Table of CFR Titles and Chapters

(Revised as of July 1, 2022)

Title 1—General Provisions

I Administrative Committee of the Federal Register (Parts 1—49)
II Office of the Federal Register (Parts 50—299)
III Administrative Conference of the United States (Parts 300—399)
IV Miscellaneous Agencies (Parts 400—599)
VI National Capital Planning Commission (Parts 600—699)

Title 2—Grants and Agreements

SUBTITLE A—OFFICE OF MANAGEMENT AND BUDGET GUIDANCE FOR GRANTS AND AGREEMENTS
I Office of Management and Budget Governmentwide Guidance for Grants and Agreements (Parts 2—199)
II Office of Management and Budget Guidance (Parts 200—299)
SUBTITLE B—FEDERAL AGENCY REGULATIONS FOR GRANTS AND AGREEMENTS
III Department of Health and Human Services (Parts 300—399)
IV Department of Agriculture (Parts 400—499)
VI Department of State (Parts 600—699)
VII Agency for International Development (Parts 700—799)
VIII Department of Veterans Affairs (Parts 800—899)
IX Department of Energy (Parts 900—999)
X Department of the Treasury (Parts 1000—1099)
XI Department of Defense (Parts 1100—1199)
XII Department of Transportation (Parts 1200—1299)
XIII Department of Commerce (Parts 1300—1399)
XIV Department of the Interior (Parts 1400—1499)
XV Environmental Protection Agency (Parts 1500—1599)
XVIII National Aeronautics and Space Administration (Parts 1800—1899)
XX United States Nuclear Regulatory Commission (Parts 2000—2099)
XXII Corporation for National and Community Service (Parts 2200—2299)
XXIII Social Security Administration (Parts 2300—2399)
XXIV Department of Housing and Urban Development (Parts 2400—2499)
XXV National Science Foundation (Parts 2500—2599)
XXVI National Archives and Records Administration (Parts 2600—2699)

Title 2—Grants and Agreements—Continued

Chap.	
XXVII	Small Business Administration (Parts 2700—2799)
XXVIII	Department of Justice (Parts 2800—2899)
XXIX	Department of Labor (Parts 2900—2999)
XXX	Department of Homeland Security (Parts 3000—3099)
XXXI	Institute of Museum and Library Services (Parts 3100—3199)
XXXII	National Endowment for the Arts (Parts 3200—3299)
XXXIII	National Endowment for the Humanities (Parts 3300—3399)
XXXIV	Department of Education (Parts 3400—3499)
XXXV	Export-Import Bank of the United States (Parts 3500—3599)
XXXVI	Office of National Drug Control Policy, Executive Office of the President (Parts 3600—3699)
XXXVII	Peace Corps (Parts 3700—3799)
LVIII	Election Assistance Commission (Parts 5800—5899)
LIX	Gulf Coast Ecosystem Restoration Council (Parts 5900—5999)

Title 3—The President

I	Executive Office of the President (Parts 100—199)

Title 4—Accounts

I	Government Accountability Office (Parts 1—199)

Title 5—Administrative Personnel

I	Office of Personnel Management (Parts 1—1199)
II	Merit Systems Protection Board (Parts 1200—1299)
III	Office of Management and Budget (Parts 1300—1399)
IV	Office of Personnel Management and Office of the Director of National Intelligence (Parts 1400—1499)
V	The International Organizations Employees Loyalty Board (Parts 1500—1599)
VI	Federal Retirement Thrift Investment Board (Parts 1600—1699)
VIII	Office of Special Counsel (Parts 1800—1899)
IX	Appalachian Regional Commission (Parts 1900—1999)
XI	Armed Forces Retirement Home (Parts 2100—2199)
XIV	Federal Labor Relations Authority, General Counsel of the Federal Labor Relations Authority and Federal Service Impasses Panel (Parts 2400—2499)
XVI	Office of Government Ethics (Parts 2600—2699)
XXI	Department of the Treasury (Parts 3100—3199)
XXII	Federal Deposit Insurance Corporation (Parts 3200—3299)
XXIII	Department of Energy (Parts 3300—3399)
XXIV	Federal Energy Regulatory Commission (Parts 3400—3499)
XXV	Department of the Interior (Parts 3500—3599)
XXVI	Department of Defense (Parts 3600—3699)

Title 5—Administrative Personnel—Continued

Chap.	
XXVIII	Department of Justice (Parts 3800—3899)
XXIX	Federal Communications Commission (Parts 3900—3999)
XXX	Farm Credit System Insurance Corporation (Parts 4000—4099)
XXXI	Farm Credit Administration (Parts 4100—4199)
XXXIII	U.S. International Development Finance Corporation (Parts 4300—4399)
XXXIV	Securities and Exchange Commission (Parts 4400—4499)
XXXV	Office of Personnel Management (Parts 4500—4599)
XXXVI	Department of Homeland Security (Parts 4600—4699)
XXXVII	Federal Election Commission (Parts 4700—4799)
XL	Interstate Commerce Commission (Parts 5000—5099)
XLI	Commodity Futures Trading Commission (Parts 5100—5199)
XLII	Department of Labor (Parts 5200—5299)
XLIII	National Science Foundation (Parts 5300—5399)
XLV	Department of Health and Human Services (Parts 5500—5599)
XLVI	Postal Rate Commission (Parts 5600—5699)
XLVII	Federal Trade Commission (Parts 5700—5799)
XLVIII	Nuclear Regulatory Commission (Parts 5800—5899)
XLIX	Federal Labor Relations Authority (Parts 5900—5999)
L	Department of Transportation (Parts 6000—6099)
LII	Export-Import Bank of the United States (Parts 6200—6299)
LIII	Department of Education (Parts 6300—6399)
LIV	Environmental Protection Agency (Parts 6400—6499)
LV	National Endowment for the Arts (Parts 6500—6599)
LVI	National Endowment for the Humanities (Parts 6600—6699)
LVII	General Services Administration (Parts 6700—6799)
LVIII	Board of Governors of the Federal Reserve System (Parts 6800—6899)
LIX	National Aeronautics and Space Administration (Parts 6900—6999)
LX	United States Postal Service (Parts 7000—7099)
LXI	National Labor Relations Board (Parts 7100—7199)
LXII	Equal Employment Opportunity Commission (Parts 7200—7299)
LXIII	Inter-American Foundation (Parts 7300—7399)
LXIV	Merit Systems Protection Board (Parts 7400—7499)
LXV	Department of Housing and Urban Development (Parts 7500—7599)
LXVI	National Archives and Records Administration (Parts 7600—7699)
LXVII	Institute of Museum and Library Services (Parts 7700—7799)
LXVIII	Commission on Civil Rights (Parts 7800—7899)
LXIX	Tennessee Valley Authority (Parts 7900—7999)
LXX	Court Services and Offender Supervision Agency for the District of Columbia (Parts 8000—8099)
LXXI	Consumer Product Safety Commission (Parts 8100—8199)
LXXIII	Department of Agriculture (Parts 8300—8399)

Title 5—Administrative Personnel—Continued

Chap.	
LXXIV	Federal Mine Safety and Health Review Commission (Parts 8400—8499)
LXXVI	Federal Retirement Thrift Investment Board (Parts 8600—8699)
LXXVII	Office of Management and Budget (Parts 8700—8799)
LXXX	Federal Housing Finance Agency (Parts 9000—9099)
LXXXIII	Special Inspector General for Afghanistan Reconstruction (Parts 9300—9399)
LXXXIV	Bureau of Consumer Financial Protection (Parts 9400—9499)
LXXXVI	National Credit Union Administration (Parts 9600—9699)
XCVII	Department of Homeland Security Human Resources Management System (Department of Homeland Security—Office of Personnel Management) (Parts 9700—9799)
XCVIII	Council of the Inspectors General on Integrity and Efficiency (Parts 9800—9899)
XCIX	Military Compensation and Retirement Modernization Commission (Parts 9900—9999)
C	National Council on Disability (Parts 10000—10049)
CI	National Mediation Board (Parts 10100—10199)
CII	U.S. Office of Special Counsel (Parts 10200—10299)

Title 6—Domestic Security

I	Department of Homeland Security, Office of the Secretary (Parts 1—199)
X	Privacy and Civil Liberties Oversight Board (Parts 1000—1099)

Title 7—Agriculture

SUBTITLE A—OFFICE OF THE SECRETARY OF AGRICULTURE (PARTS 0—26)

SUBTITLE B—REGULATIONS OF THE DEPARTMENT OF AGRICULTURE

I	Agricultural Marketing Service (Standards, Inspections, Marketing Practices), Department of Agriculture (Parts 27—209)
II	Food and Nutrition Service, Department of Agriculture (Parts 210—299)
III	Animal and Plant Health Inspection Service, Department of Agriculture (Parts 300—399)
IV	Federal Crop Insurance Corporation, Department of Agriculture (Parts 400—499)
V	Agricultural Research Service, Department of Agriculture (Parts 500—599)
VI	Natural Resources Conservation Service, Department of Agriculture (Parts 600—699)
VII	Farm Service Agency, Department of Agriculture (Parts 700—799)
VIII	Agricultural Marketing Service (Federal Grain Inspection Service, Fair Trade Practices Program), Department of Agriculture (Parts 800—899)

Title 7—Agriculture—Continued

Chap.	
IX	Agricultural Marketing Service (Marketing Agreements and Orders; Fruits, Vegetables, Nuts), Department of Agriculture (Parts 900—999)
X	Agricultural Marketing Service (Marketing Agreements and Orders; Milk), Department of Agriculture (Parts 1000—1199)
XI	Agricultural Marketing Service (Marketing Agreements and Orders; Miscellaneous Commodities), Department of Agriculture (Parts 1200—1299)
XIV	Commodity Credit Corporation, Department of Agriculture (Parts 1400—1499)
XV	Foreign Agricultural Service, Department of Agriculture (Parts 1500—1599)
XVI	[Reserved]
XVII	Rural Utilities Service, Department of Agriculture (Parts 1700—1799)
XVIII	Rural Housing Service, Rural Business-Cooperative Service, Rural Utilities Service, and Farm Service Agency, Department of Agriculture (Parts 1800—2099)
XX	[Reserved]
XXV	Office of Advocacy and Outreach, Department of Agriculture (Parts 2500—2599)
XXVI	Office of Inspector General, Department of Agriculture (Parts 2600—2699)
XXVII	Office of Information Resources Management, Department of Agriculture (Parts 2700—2799)
XXVIII	Office of Operations, Department of Agriculture (Parts 2800—2899)
XXIX	Office of Energy Policy and New Uses, Department of Agriculture (Parts 2900—2999)
XXX	Office of the Chief Financial Officer, Department of Agriculture (Parts 3000—3099)
XXXI	Office of Environmental Quality, Department of Agriculture (Parts 3100—3199)
XXXII	Office of Procurement and Property Management, Department of Agriculture (Parts 3200—3299)
XXXIII	Office of Transportation, Department of Agriculture (Parts 3300—3399)
XXXIV	National Institute of Food and Agriculture (Parts 3400—3499)
XXXV	Rural Housing Service, Department of Agriculture (Parts 3500—3599)
XXXVI	National Agricultural Statistics Service, Department of Agriculture (Parts 3600—3699)
XXXVII	Economic Research Service, Department of Agriculture (Parts 3700—3799)
XXXVIII	World Agricultural Outlook Board, Department of Agriculture (Parts 3800—3899)
XLI	[Reserved]
XLII	Rural Business-Cooperative Service and Rural Utilities Service, Department of Agriculture (Parts 4200—4299)

Title 7—Agriculture—Continued

Chap.

L Rural Business-Cooperative Service, and Rural Utilities Service, Department of Agriculture (Parts 5000—5099)

Title 8—Aliens and Nationality

I Department of Homeland Security (Parts 1—499)

V Executive Office for Immigration Review, Department of Justice (Parts 1000—1399)

Title 9—Animals and Animal Products

I Animal and Plant Health Inspection Service, Department of Agriculture (Parts 1—199)

II Agricultural Marketing Service (Fair Trade Practices Program), Department of Agriculture (Parts 200—299)

III Food Safety and Inspection Service, Department of Agriculture (Parts 300—599)

Title 10—Energy

I Nuclear Regulatory Commission (Parts 0—199)

II epartment of Energy (Parts 200—699)

III Department of Energy (Parts 700—999)

X Department of Energy (General Provisions) (Parts 1000—1099)

XIII Nuclear Waste Technical Review Board (Parts 1300—1399)

XVII Defense Nuclear Facilities Safety Board (Parts 1700—1799)

XVIII Northeast Interstate Low-Level Radioactive Waste Commission (Parts 1800—1899)

Title 11—Federal Elections

I Federal Election Commission (Parts 1—9099)

II Election Assistance Commission (Parts 9400—9499)

Title 12—Banks and Banking

I Comptroller of the Currency, Department of the Treasury (Parts 1—199)

II Federal Reserve System (Parts 200—299)

III Federal Deposit Insurance Corporation (Parts 300—399)

IV Export-Import Bank of the United States (Parts 400—499)

V [Reserved]

VI Farm Credit Administration (Parts 600—699)

VII National Credit Union Administration (Parts 700—799)

VIII Federal Financing Bank (Parts 800—899)

IX (Parts 900—999) [Reserved]

X Bureau of Consumer Financial Protection (Parts 1000—1099)

Title 12—Banks and Banking—Continued

Chap.

XI Federal Financial Institutions Examination Council (Parts 1100—1199)

XII Federal Housing Finance Agency (Parts 1200—1299)

XIII Financial Stability Oversight Council (Parts 1300—1399)

XIV Farm Credit System Insurance Corporation (Parts 1400—1499)

XV Department of the Treasury (Parts 1500—1599)

XVI Office of Financial Research, Department of the Treasury (Parts 1600—1699)

XII Office of Federal Housing Enterprise Oversight, Department of Housing and Urban Development (Parts 1700—1799)

XIII Community Development Financial Institutions Fund, Department of the Treasury (Parts 1800—1899)

Title 13—Business Credit and Assistance

I Small Business Administration (Parts 1—199)

III Economic Development Administration, Department of Commerce (Parts 300—399)

IV Emergency Steel Guarantee Loan Board (Parts 400—499)

V Emergency Oil and Gas Guaranteed Loan Board (Parts 500—599)

Title 14—Aeronautics and Space

I Federal Aviation Administration, Department of Transportation (Parts 1—199)

II Office of the Secretary, Department of Transportation (Aviation Proceedings) (Parts 200—399)

III Commercial Space Transportation, Federal Aviation Administration, Department of Transportation (Parts 400—1199)

V National Aeronautics and Space Administration (Parts 1200—1299)

VI Air Transportation System Stabilization (Parts 1300—1399)

Title 15—Commerce and Foreign Trade

SUBTITLE A—OFFICE OF THE SECRETARY OF COMMERCE (PARTS 0—29)

SUBTITLE B—REGULATIONS RELATING TO COMMERCE AND FOREIGN TRADE

I Bureau of the Census, Department of Commerce (Parts 30—199)

II National Institute of Standards and Technology, Department of Commerce (Parts 200—299)

III International Trade Administration, Department of Commerce (Parts 300—399)

IV Foreign-Trade Zones Board, Department of Commerce (Parts 400—499)

VII Bureau of Industry and Security, Department of Commerce (Parts 700—799)

Title 15—Commerce and Foreign Trade—Continued

Chap.

VIII Bureau of Economic Analysis, Department of Commerce (Parts 800—899)

IX ational Oceanic and Atmospheric Administration, Department of Commerce (Parts 900—999)

XI National Technical Information Service, Department of Commerce (Parts 1100—1199)

XIII East-West Foreign Trade Board (Parts 1300—1399)

XIV Minority Business Development Agency (Parts 1400—1499)

XV Office of the Under-Secretary for Economic Affairs, Department of Commerce (Parts 1500—1599)

SUBTITLE C—REGULATIONS RELATING TO FOREIGN TRADE AGREEMENTS

XX Office of the United States Trade Representative (Parts 2000—2099)

SUBTITLE D—REGULATIONS RELATING TO TELECOMMUNICATIONS AND INFORMATION

XXIII National Telecommunications and Information Administration, Department of Commerce (Parts 2300—2399) [Reserved]

Title 16—Commercial Practices

I Federal Trade Commission (Parts 0—999)

II Consumer Product Safety Commission (Parts 1000—1799)

Title 17—Commodity and Securities Exchanges

I Commodity Futures Trading Commission (Parts 1—199)

II Securities and Exchange Commission (Parts 200—399)

IV Department of the Treasury (Parts 400—499)

Title 18—Conservation of Power and Water Resources

I Federal Energy Regulatory Commission, Department of Energy (Parts 1—399)

III Delaware River Basin Commission (Parts 400—499)

VI Water Resources Council (Parts 700—799)

VIII Susquehanna River Basin Commission (Parts 800—899)

XIII Tennessee Valley Authority (Parts 1300—1399)

Title 19—Customs Duties

I U.S. Customs and Border Protection, Department of Homeland Security; Department of the Treasury (Parts 0—199)

II nited States International Trade Commission (Parts 200—299)

III nternational Trade Administration, Department of Commerce (Parts 300—399)

IV U.S. Immigration and Customs Enforcement, Department of Homeland Security (Parts 400—599) [Reserved]

Title 20—Employees' Benefits

Chap.

I Office of Workers' Compensation Programs, Department of Labor (Parts 1—199)

II Railroad Retirement Board (Parts 200—399)

III Social Security Administration (Parts 400—499)

IV Employees' Compensation Appeals Board, Department of Labor (Parts 500—599)

V Employment and Training Administration, Department of Labor (Parts 600—699)

VI Office of Workers' Compensation Programs, Department of Labor (Parts 700—799)

VII Benefits Review Board, Department of Labor (Parts 800—899)

VIII Joint Board for the Enrollment of Actuaries (Parts 900—999)

IX Office of the Assistant Secretary for Veterans' Employment and Training Service, Department of Labor (Parts 1000—1099)

Title 21—Food and Drugs

I Food and Drug Administration, Department of Health and Human Services (Parts 1—1299)

II Drug Enforcement Administration, Department of Justice (Parts 1300—1399)

III Office of National Drug Control Policy (Parts 1400—1499)

Title 22—Foreign Relations

I Department of State (Parts 1—199)

II Agency for International Development (Parts 200—299)

III Peace Corps (Parts 300—399)

IV International Joint Commission, United States and Canada (Parts 400—499)

V United States Agency for Global Media (Parts 500—599)

VI U.S. International Development Finance Corporation (Parts 700—799)

IX Foreign Service Grievance Board (Parts 900—999)

X Inter-American Foundation (Parts 1000—1099)

XI International Boundary and Water Commission, United States and Mexico, United States Section (Parts 1100—1199)

XII United States International Development Cooperation Agency (Parts 1200—1299)

XIII Millennium Challenge Corporation (Parts 1300—1399)

XIV Foreign Service Labor Relations Board; Federal Labor Relations Authority; General Counsel of the Federal Labor Relations Authority; and the Foreign Service Impasse Disputes Panel (Parts 1400—1499)

XV African Development Foundation (Parts 1500—1599)

XVI Japan-United States Friendship Commission (Parts 1600—1699)

XVII United States Institute of Peace (Parts 1700—1799)

Title 23—Highways

Chap.

I Federal Highway Administration, Department of Transportation (Parts 1—999)

II National Highway Traffic Safety Administration and Federal Highway Administration, Department of Transportation (Parts 1200—1299)

III National Highway Traffic Safety Administration, Department of Transportation (Parts 1300—1399)

Title 24—Housing and Urban Development

SUBTITLE A—OFFICE OF THE SECRETARY, DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT (PARTS 0—99)

SUBTITLE B—REGULATIONS RELATING TO HOUSING AND URBAN DEVELOPMENT

I Office of Assistant Secretary for Equal Opportunity, Department of Housing and Urban Development (Parts 100—199)

II Office of Assistant Secretary for Housing-Federal Housing Commissioner, Department of Housing and Urban Development (Parts 200—299)

III Government National Mortgage Association, Department of Housing and Urban Development (Parts 300—399)

IV Office of Housing and Office of Multifamily Housing Assistance Restructuing, Department of Housing and Urban Development (Parts 400—499)

V ffice of Assistant Secretary for Community Planning and Development, Department of Housing and Urban Development (Parts 500—599)

VI Office of Assistant Secretary for Community Planning and Development, Department of Housing and Urban Development (Parts 600—699) [Reserved]

VII Office of the Secretary, Department of Housing and Urban Development (Housing Assistance Programs and Public and Indian Housing Programs) (Parts 700—799)

VIII Office of the Assistant Secretary for Housing—Federal Housing Commissioner, Department of Housing and Urban Development (Section 8 Housing Assistance Programs, Section 202 Direct Loan Program, Section 202 Supportive Housing for the Elderly Program and Section 811 Supportive Housing for Persons With Disabilities Program) (Parts 800—899)

IX Office of Assistant Secretary for Public and Indian Housing, Department of Housing and Urban Development (Parts 900—1699)

X Office of Assistant Secretary for Housing—Federal Housing Commissioner, Department of Housing and Urban Development (Interstate Land Sales Registration Program) (Parts 1700—1799) [Reserved]

XII Office of Inspector General, Department of Housing and Urban Development (Parts 2000—2099)

XV Emergency Mortgage Insurance and Loan Programs, Department of Housing and Urban Development (Parts 2700—2799) [Reserved]

Title 24—Housing and Urban Development—Continued

Chap.

XX Office of Assistant Secretary for Housing—Federal Housing Commissioner, Department of Housing and Urban Development (Parts 3200—3899)

XXIV Board of Directors of the HOPE for Homeowners Program (Parts 4000—4099) [Reserved]

XXV Neighborhood Reinvestment Corporation (Parts 4100—4199)

Title 25—Indians

I Bureau of Indian Affairs, Department of the Interior (Parts 1—299)

II Indian Arts and Crafts Board, Department of the Interior (Parts 300—399)

III National Indian Gaming Commission, Department of the Interior (Parts 500—599)

IV ffice of Navajo and Hopi Indian Relocation (Parts 700—899)

V Bureau of Indian Affairs, Department of the Interior, and Indian Health Service, Department of Health and Human Services (Part 900—999)

VI Office of the Assistant Secretary, Indian Affairs, Department of the Interior (Parts 1000—1199)

VII Office of the Special Trustee for American Indians, Department of the Interior (Parts 1200—1299)

Title 26—Internal Revenue

I Internal Revenue Service, Department of the Treasury (Parts 1—End)

Title 27—Alcohol, Tobacco Products and Firearms

I Alcohol and Tobacco Tax and Trade Bureau, Department of the Treasury (Parts 1—399)

II Bureau of Alcohol, Tobacco, Firearms, and Explosives, Department of Justice (Parts 400—799)

Title 28—Judicial Administration

I Department of Justice (Parts 0—299)

III Federal Prison Industries, Inc., Department of Justice (Parts 300—399)

V Bureau of Prisons, Department of Justice (Parts 500—599)

VI Offices of Independent Counsel, Department of Justice (Parts 600—699)

VII Office of Independent Counsel (Parts 700—799)

VIII Court Services and Offender Supervision Agency for the District of Columbia (Parts 800—899)

IX ational Crime Prevention and Privacy Compact Council (Parts 900—999)

Title 28—Judicial Administration—Continued

Chap.

XI Department of Justice and Department of State (Parts 1100—1199)

Title 29—Labor

SUBTITLE A—OFFICE OF THE SECRETARY OF LABOR (PARTS 0—99)

SUBTITLE B—REGULATIONS RELATING TO LABOR

I National Labor Relations Board (Parts 100—199)

II Office of Labor-Management Standards, Department of Labor (Parts 200—299)

III National Railroad Adjustment Board (Parts 300—399)

IV Office of Labor-Management Standards, Department of Labor (Parts 400—499)

V Wage and Hour Division, Department of Labor (Parts 500—899)

IX Construction Industry Collective Bargaining Commission (Parts 900—999)

X National Mediation Board (Parts 1200—1299)

XII Federal Mediation and Conciliation Service (Parts 1400—1499)

XIV Equal Employment Opportunity Commission (Parts 1600—1699)

XVII Occupational Safety and Health Administration, Department of Labor (Parts 1900—1999)

XX Occupational Safety and Health Review Commission (Parts 2200—2499)

XXV Employee Benefits Security Administration, Department of Labor (Parts 2500—2599)

XXVII Federal Mine Safety and Health Review Commission (Parts 2700—2799)

XL Pension Benefit Guaranty Corporation (Parts 4000—4999)

Title 30—Mineral Resources

I Mine Safety and Health Administration, Department of Labor (Parts 1—199)

II Bureau of Safety and Environmental Enforcement, Department of the Interior (Parts 200—299)

IV Geological Survey, Department of the Interior (Parts 400—499)

V Bureau of Ocean Energy Management, Department of the Interior (Parts 500—599)

VII Office of Surface Mining Reclamation and Enforcement, Department of the Interior (Parts 700—999)

XII Office of Natural Resources Revenue, Department of the Interior (Parts 1200—1299)

Title 31—Money and Finance: Treasury

SUBTITLE A—OFFICE OF THE SECRETARY OF THE TREASURY (PARTS 0—50)

SUBTITLE B—REGULATIONS RELATING TO MONEY AND FINANCE

Title 31—Money and Finance: Treasury—Continued

Chap.

I Monetary Offices, Department of the Treasury (Parts 1—199)

II Fiscal Service, Department of the Treasury (Parts 200—399)

IV Secret Service, Department of the Treasury (Parts 400—499)

V Office of Foreign Assets Control, Department of the Treasury (Parts 500—599)

VI Bureau of Engraving and Printing, Department of the Treasury (Parts 600—699)

VII Federal Law Enforcement Training Center, Department of the Treasury (Parts 700—799)

VIII Office of Investment Security, Department of the Treasury (Parts 800—899)

IX Federal Claims Collection Standards (Department of the Treasury—Department of Justice) (Parts 900—999)

X Financial Crimes Enforcement Network, Department of the Treasury (Parts 1000—1099)

Title 32—National Defense

SUBTITLE A—DEPARTMENT OF DEFENSE

I Office of the Secretary of Defense (Parts 1—399)

V Department of the Army (Parts 400—699)

VI Department of the Navy (Parts 700—799)

VII Department of the Air Force (Parts 800—1099)

SUBTITLE B—OTHER REGULATIONS RELATING TO NATIONAL DEFENSE

XII Department of Defense, Defense Logistics Agency (Parts 1200—1299)

XVI Selective Service System (Parts 1600—1699)

XVII Office of the Director of National Intelligence (Parts 1700—1799)

XVIII National Counterintelligence Center (Parts 1800—1899)

XIX Central Intelligence Agency (Parts 1900—1999)

XX Information Security Oversight Office, National Archives and Records Administration (Parts 2000—2099)

XXI National Security Council (Parts 2100—2199)CHAPNO≤XXIV

Office of Science and Technology Policy (Parts 2400—2499)

XXVII Office for Micronesian Status Negotiations (Parts 2700—2799)

XXVIII Office of the Vice President of the United States (Parts 2800—2899)

Title 33—Navigation and Navigable Waters

I Coast Guard, Department of Homeland Security (Parts 1—199)

II Corps of Engineers, Department of the Army, Department of Defense (Parts 200—399)

IV Great Lakes St. Lawrence Seaway Development Corporation, Department of Transportation (Parts 400—499)

Title 34—Education

Chap.

SUBTITLE A—OFFICE OF THE SECRETARY, DEPARTMENT OF EDUCATION (PARTS 1—99)

SUBTITLE B—REGULATIONS OF THE OFFICES OF THE DEPARTMENT OF EDUCATION

I Office for Civil Rights, Department of Education (Parts 100—199)

II Office of Elementary and Secondary Education, Department of Education (Parts 200—299)

III Office of Special Education and Rehabilitative Services, Department of Education (Parts 300—399)

IV Office of Career, Technical, and Adult Education, Department of Education (Parts 400—499)

V Office of Bilingual Education and Minority Languages Affairs, Department of Education (Parts 500—599) [Reserved]

VI Office of Postsecondary Education, Department of Education (Parts 600—699)

VII Office of Educational Research and Improvement, Department of Education (Parts 700—799) [Reserved]

SUBTITLE C—REGULATIONS RELATING TO EDUCATION

XI [Reserved]

XII National Council on Disability (Parts 1200—1299)

Title 35 [Reserved]

Title 36—Parks, Forests, and Public Property

I National Park Service, Department of the Interior (Parts 1—199)

II Forest Service, Department of Agriculture (Parts 200—299)

III Corps of Engineers, Department of the Army (Parts 300—399)CHAPNO≤IV

American Battle Monuments Commission (Parts 400—499)

V Smithsonian Institution (Parts 500—599)

VI [Reserved]

VII Library of Congress (Parts 700—799)

VIII Advisory Council on Historic Preservation (Parts 800—899)

IX Pennsylvania Avenue Development Corporation (Parts 900—999)

X Presidio Trust (Parts 1000—1099)

XI Architectural and Transportation Barriers Compliance Board (Parts 1100—1199)

XII National Archives and Records Administration (Parts 1200—1299)

XV Oklahoma City National Memorial Trust (Parts 1500—1599)

XVI Morris K. Udall Scholarship and Excellence in National Environmental Policy Foundation (Parts 1600—1699)

Title 37—Patents, Trademarks, and Copyrights

I United States Patent and Trademark Office, Department of Commerce (Parts 1—199)

II U.S. Copyright Office, Library of Congress (Parts 200—299)

Title 37—Patents, Trademarks, and Copyrights—Continued

Chap.

III Copyright Royalty Board, Library of Congress (Parts 300—399)

IV National Institute of Standards and Technology, Department of Commerce (Parts 400—599)

Title 38—Pensions, Bonuses, and Veterans' Relief

I Department of Veterans Affairs (Parts 0—199)

II Armed Forces Retirement Home (Parts 200—299)

Title 39—Postal Service

I United States Postal Service (Parts 1—999)

III Postal Regulatory Commission (Parts 3000—3099)

Title 40—Protection of Environment

I Environmental Protection Agency (Parts 1—1099)CHAPNO≤IV

Environmental Protection Agency and Department of Justice (Parts 1400—1499)CHAPNO≤V

Council on Environmental Quality (Parts 1500—1599)

VI Chemical Safety and Hazard Investigation Board (Parts 1600—1699)

VII Environmental Protection Agency and Department of Defense; Uniform National Discharge Standards for Vessels of the Armed Forces (Parts 1700—1799)

VIII Gulf Coast Ecosystem Restoration Council (Parts 1800—1899)

IX Federal Permitting Improvement Steering Council (Part 1900)

Title 41—Public Contracts and Property Management

SUBTITLE A—FEDERAL PROCUREMENT REGULATIONS SYSTEM [NOTE]

SUBTITLE B—OTHER PROVISIONS RELATING TO PUBLIC CONTRACTS

50 Public Contracts, Department of Labor (Parts 50–1—50–999)

51 Committee for Purchase From People Who Are Blind or Severely Disabled (Parts 51–1—51–99)

60 Office of Federal Contract Compliance Programs, Equal Employment Opportunity, Department of Labor (Parts 60–1—60–999)

61 Office of the Assistant Secretary for Veterans' Employment and Training Service, Department of Labor (Parts 61–1—61–999)

62—100 [Reserved]

SUBTITLE C—FEDERAL PROPERTY MANAGEMENT REGULATIONS SYSTEM

101 Federal Property Management Regulations (Parts 101–1—101–99)

102 Federal Management Regulation (Parts 102–1—102–299)

103—104 [Reserved]

105 General Services Administration (Parts 105–1—105–999)

Title 41—Public Contracts and Property Management—Continued

Chap.

109 Department of Energy Property Management Regulations (Parts 109–1—109–99)

114 Department of the Interior (Parts 114–1—114–99)

115 Environmental Protection Agency (Parts 15–1—115–99)

128 Department of Justice (Parts 128–1—128–99)

129—200 [Reserved]

SUBTITLE D—FEDERAL ACQUISITION SUPPLY CHAIN SECURITY

201 Federal Acquisition Security Council (Parts 201–1—201–99)SUBTITL≤Subtitle E [Reserved]

SUBTITLE F—FEDERAL TRAVEL REGULATION SYSTEM

300 General (Parts 300–1—300–99)

301 Temporary Duty (TDY) Travel Allowances (Parts 301–1—301–99)

302 Relocation Allowances (Parts 302–1—302–99)

303 Payment of Expenses Connected with the Death of Certain Employees (Part 303–1—303–99)

304 Payment of Travel Expenses from a Non-Federal Source (Parts 304–1—304–99)

Title 42—Public Health

I Public Health Service, Department of Health and Human Services (Parts 1—199)

II—III [Reserved]

IV Centers for Medicare & Medicaid Services, Department of Health and Human Services (Parts 400—699)

V Office of Inspector General-Health Care, Department of Health and Human Services (Parts 1000—1099)

Title 43—Public Lands: Interior

SUBTITLE A—OFFICE OF THE SECRETARY OF THE INTERIOR (PARTS 1—199)

SUBTITLE B—REGULATIONS RELATING TO PUBLIC LANDS

I Bureau of Reclamation, Department of the Interior (Parts 400—999)

II Bureau of Land Management, Department of the Interior (Parts 1000—9999)

III Utah Reclamation Mitigation and Conservation Commission (Parts 10000—10099)

Title 44—Emergency Management and Assistance

I Federal Emergency Management Agency, Department of Homeland Security (Parts 0—399)

IV Department of Commerce and Department of Transportation (Parts 400—499)

Title 45—Public Welfare

Chap.

SUBTITLE A—DEPARTMENT OF HEALTH AND HUMAN SERVICES (PARTS 1—199)

SUBTITLE B—REGULATIONS RELATING TO PUBLIC WELFARE

II Office of Family Assistance (Assistance Programs), Administration for Children and Families, Department of Health and Human Services (Parts 200—299)

III Office of Child Support Enforcement (Child Support Enforcement Program), Administration for Children and Families, Department of Health and Human Services (Parts 300—399)

IV Office of Refugee Resettlement, Administration for Children and Families, Department of Health and Human Services (Parts 400—499)

V Foreign Claims Settlement Commission of the United States, Department of Justice (Parts 500—599)

VI National Science Foundation (Parts 600—699)

VII Commission on Civil Rights (Parts 700—799)

VIII Office of Personnel Management (Parts 800—899)

IX Denali Commission (Parts 900—999)

X Office of Community Services, Administration for Children and Families, Department of Health and Human Services (Parts 1000—1099)

XI National Foundation on the Arts and the Humanities (Parts 1100—1199)

XII Corporation for National and Community Service (Parts 1200—1299)

XIII Administration for Children and Families, Department of Health and Human Services (Parts 1300—1399)

XVI Legal Services Corporation (Parts 1600—1699)

XVII National Commission on Libraries and Information Science (Parts 1700—1799)

XVIII Harry S. Truman Scholarship Foundation (Parts 1800—1899)

XXI Commission of Fine Arts (Parts 2100—2199)

XXIII Arctic Research Commission (Parts 2300—2399)

XXIV James Madison Memorial Fellowship Foundation (Parts 2400—2499)

XXV Corporation for National and Community Service (Parts 2500—2599)

Title 46—Shipping

I Coast Guard, Department of Homeland Security (Parts 1—199)

II Maritime Administration, Department of Transportation (Parts 200—399)

III Coast Guard (Great Lakes Pilotage), Department of Homeland Security (Parts 400—499)

IV Federal Maritime Commission (Parts 500—599)

Title 47—Telecommunication

Chap.

I Federal Communications Commission (Parts 0—199)

II Office of Science and Technology Policy and National Security Council (Parts 200—299)

III National Telecommunications and Information Administration, Department of Commerce (Parts 300—399)

IV National Telecommunications and Information Administration, Department of Commerce, and National Highway Traffic Safety Administration, Department of Transportation (Parts 400—499)

V The First Responder Network Authority (Parts 500—599)

Title 48—Federal Acquisition Regulations System

1 Federal Acquisition Regulation (Parts 1—99)

2 Defense Acquisition Regulations System, Department of Defense (Parts 200—299)

3 Department of Health and Human Services (Parts 300—399)

4 Department of Agriculture (Parts 400—499)

5 General Services Administration (Parts 500—599)

6 Department of State (Parts 600—699)

7 Agency for International Development (Parts 700—799)

8 Department of Veterans Affairs (Parts 800—899)

9 Department of Energy (Parts 900—999)

10 Department of the Treasury (Parts 1000—1099)

12 Department of Transportation (Parts 1200—1299)

13 Department of Commerce (Parts 1300—1399)

14 Department of the Interior (Parts 1400—1499)

15 Environmental Protection Agency (Parts 1500—1599)

16 Office of Personnel Management Federal Employees Health Benefits Acquisition Regulation (Parts 1600—1699)

17 Office of Personnel Management (Parts 1700—1799)

18 National Aeronautics and Space Administration (Parts 1800—1899)

19 Broadcasting Board of Governors (Parts 1900—1999)

20 Nuclear Regulatory Commission (Parts 2000—2099)

21 Office of Personnel Management, Federal Employees Group Life Insurance Federal Acquisition Regulation (Parts 2100—2199)

23 Social Security Administration (Parts 2300—2399)

24 Department of Housing and Urban Development (Parts 2400—2499)

25 National Science Foundation (Parts 2500—2599)

28 Department of Justice (Parts 2800—2899)

29 Department of Labor (Parts 2900—2999)

30 Department of Homeland Security, Homeland Security Acquisition Regulation (HSAR) (Parts 3000—3099)

34 Department of Education Acquisition Regulation (Parts 3400—3499)

Chap.

51 Department of the Army Acquisition Regulations (Parts 5100—5199) [Reserved]

52 Department of the Navy Acquisition Regulations (Parts 5200—5299)

53 Department of the Air Force Federal Acquisition Regulation Supplement (Parts 5300—5399) [Reserved]

54 Defense Logistics Agency, Department of Defense (Parts 5400—5499)

57 African Development Foundation (Parts 5700—5799)

61 Civilian Board of Contract Appeals, General Services Administration (Parts 6100—6199)

99 Cost Accounting Standards Board, Office of Federal Procurement Policy, Office of Management and Budget (Parts 9900—9999)

Title 49—Transportation

SUBTITLE A—OFFICE OF THE SECRETARY OF TRANSPORTATION (PARTS 1—99)

SUBTITLE B—OTHER REGULATIONS RELATING TO TRANSPORTATION

I Pipeline and Hazardous Materials Safety Administration, Department of Transportation (Parts 100—199)

II Federal Railroad Administration, Department of Transportation (Parts 200—299)

III Federal Motor Carrier Safety Administration, Department of Transportation (Parts 300—399)

IV Coast Guard, Department of Homeland Security (Parts 400—499)

V National Highway Traffic Safety Administration, Department of Transportation (Parts 500—599)

VI Federal Transit Administration, Department of Transportation (Parts 600—699)

VII National Railroad Passenger Corporation (AMTRAK) (Parts 700—799)

VIII National Transportation Safety Board (Parts 800—999)

X Surface Transportation Board (Parts 1000—1399)

XI Research and Innovative Technology Administration, Department of Transportation (Parts 1400—1499) [Reserved]

XII Transportation Security Administration, Department of Homeland Security (Parts 1500—1699)

Title 50—Wildlife and Fisheries

I United States Fish and Wildlife Service, Department of the Interior (Parts 1—199)

II National Marine Fisheries Service, National Oceanic and Atmospheric Administration, Department of Commerce (Parts 200—299)

III International Fishing and Related Activities (Parts 300—399)

Title 50—Wildlife and Fisheries—Continued

Chap.

IV Joint Regulations (United States Fish and Wildlife Service, Department of the Interior and National Marine Fisheries Service, National Oceanic and Atmospheric Administration, Department of Commerce); Endangered Species Committee Regulations (Parts 400—499)

V Marine Mammal Commission (Parts 500—599)

VI Fishery Conservation and Management, National Oceanic and Atmospheric Administration, Department of Commerce (Parts 600—699)

Alphabetical List of Agencies Appearing in the CFR

(Revised as of July 1, 2022)

Agency	CFR Title, Subtitle or Chapter
Administrative Conference of the United States	1, III
Advisory Council on Historic Preservation	36, VIII
Advocacy and Outreach, Office of	7, XXV
Afghanistan Reconstruction, Special Inspector General for	5, LXXXIII
African Development Foundation	22, XV
Federal Acquisition Regulation	48, 57
Agency for International Development	2, VII; 22, II
Federal Acquisition Regulation	48, 7
Agricultural Marketing Service	7, I, VIII, IX, X, XI; 9, II
Agricultural Research Service	7, V
Agriculture, Department of	2, IV; 5, LXXIII
Advocacy and Outreach, Office of	7, XXV
Agricultural Marketing Service	7, I, VIII, IX, X, XI; 9, II
Agricultural Research Service	7, V
Animal and Plant Health Inspection Service	7, III; 9, I
Chief Financial Officer, Office of	7, XXX
Commodity Credit Corporation	7, XIV
Economic Research Service	7, XXXVII
Energy Policy and New Uses, Office of	2, IX; 7, XXIX
Environmental Quality, Office of	7, XXXI
Farm Service Agency	7, VII, XVIII
Federal Acquisition Regulation	48, 4
Federal Crop Insurance Corporation	7, IV
Food and Nutrition Service	7, II
Food Safety and Inspection Service	9, III
Foreign Agricultural Service	7, XV
Forest Service	36, II
Information Resources Management, Office of	7, XXVII
Inspector General, Office of	7, XXVI
National Agricultural Library	7, XLI
National Agricultural Statistics Service	7, XXXVI
National Institute of Food and Agriculture	7, XXXIV
Natural Resources Conservation Service	7, VI
Operations, Office of	7, XXVIII
Procurement and Property Management, Office of	7, XXXII
Rural Business-Cooperative Service	7, XVIII, XLII
Rural Development Administration	7, XLII
Rural Housing Service	7, XVIII, XXXV
Rural Utilities Service	7, XVII, XVIII, XLII
Secretary of Agriculture, Office of	7, Subtitle A
Transportation, Office of	7, XXXIII
World Agricultural Outlook Board	7, XXXVIII
Air Force, Department of	32, VII
Federal Acquisition Regulation Supplement	48, 53
Air Transportation Stabilization Board	14, VI
Alcohol and Tobacco Tax and Trade Bureau	27, I
Alcohol, Tobacco, Firearms, and Explosives, Bureau of	27, II
AMTRAK	49, VII
American Battle Monuments Commission	36, IV
American Indians, Office of the Special Trustee	25, VII
Animal and Plant Health Inspection Service	7, III; 9, I
Appalachian Regional Commission	5, IX
Architectural and Transportation Barriers Compliance Board	36, XI

Agency	CFR Title, Subtitle or Chapter
Arctic Research Commission	45, XXIII
Armed Forces Retirement Home	5, XI; 38, II
Army, Department of	32, V
Engineers, Corps of	33, II; 36, III
Federal Acquisition Regulation	48, 51
Benefits Review Board	20, VII
Bilingual Education and Minority Languages Affairs, Office of	34, V
Blind or Severely Disabled, Committee for Purchase from People Who Are	41, 51
Federal Acquisition Regulation	48, 19
Career, Technical, and Adult Education, Office of	34, IV
Census Bureau	15, I
Centers for Medicare & Medicaid Services	42, IV
Central Intelligence Agency	32, XIX
Chemical Safety and Hazard Investigation Board	40, VI
Chief Financial Officer, Office of	7, XXX
Child Support Enforcement, Office of	45, III
Children and Families, Administration for	45, II, III, IV, X, XIII
Civil Rights, Commission on	5, LXVIII; 45, VII
Civil Rights, Office for	34, I
Coast Guard	33, I; 46, I; 49, IV
Coast Guard (Great Lakes Pilotage)	46, III
Commerce, Department of	2, XIII; 44, IV; 50, VI
Census Bureau	15, I
Economic Affairs, Office of the Under-Secretary for	15, XV
Economic Analysis, Bureau of	15, VIII
Economic Development Administration	13, III
Emergency Management and Assistance	44, IV
Federal Acquisition Regulation	48, 13
Foreign-Trade Zones Board	15, IV
Industry and Security, Bureau of	15, VII
International Trade Administration	15, III; 19, III
National Institute of Standards and Technology	15, II; 37, IV
National Marine Fisheries Service	50, II, IV
National Oceanic and Atmospheric Administration	15, IX; 50, II, III, IV, VI
National Technical Information Service	15, XI
National Telecommunications and Information Administration	15, XXIII; 47, III, IV
National Weather Service	15, IX
Patent and Trademark Office, United States	37, I
Secretary of Commerce, Office of	15, Subtitle A
Commercial Space Transportation	14, III
Commodity Credit Corporation	7, XIV
Commodity Futures Trading Commission	5, XLI; 17, I
Community Planning and Development, Office of Assistant Secretary for	24, V, VI
Community Services, Office of	45, X
Comptroller of the Currency	12, I
Construction Industry Collective Bargaining Commission	29, IX
Consumer Financial Protection Bureau	5, LXXXIV; 12, X
Consumer Product Safety Commission	5, LXXI; 16, II
Copyright Royalty Board	37, III
Corporation for National and Community Service	2, XXII; 45, XII, XXV
Cost Accounting Standards Board	48, 99
Council on Environmental Quality	40, V
Council of the Inspectors General on Integrity and Efficiency	5, XCVIII
Court Services and Offender Supervision Agency for the District of Columbia	5, LXX; 28, VIII
Customs and Border Protection	19, I
Defense, Department of	2, XI; 5, XXVI; 32, Subtitle A; 40, VII
Advanced Research Projects Agency	32, I
Air Force Department	32, VII
Army Department	32, V; 33, II; 36, III; 48, 51
Defense Acquisition Regulations System	48, 2
Defense Intelligence Agency	32, I

Agency	CFR Title, Subtitle or Chapter
Defense Logistics Agency	32, I, XII; 48, 54
Engineers, Corps of	33, II; 36, III
National Imagery and Mapping Agency	32, I
Navy, Department of	32, VI; 48, 52
Secretary of Defense, Office of	2, XI; 32, I
Defense Contract Audit Agency	32, I
Defense Intelligence Agency	32, I
Defense Logistics Agency	32, XII; 48, 54
Defense Nuclear Facilities Safety Board	10, XVII
Delaware River Basin Commission	18, III
Denali Commission	45, IX
Disability, National Council on	5, C; 34, XII
District of Columbia, Court Services and Offender Supervision Agency for the	5, LXX; 28, VIII
Drug Enforcement Administration	21, II
East-West Foreign Trade Board	15, XIII
Economic Affairs, Office of the Under-Secretary for	15, XV
Economic Analysis, Bureau of	15, VIII
Economic Development Administration	13, III
Economic Research Service	7, XXXVII
Education, Department of	2, XXXIV; 5, LIII
Bilingual Education and Minority Languages Affairs, Office of	34, V
Career, Technical, and Adult Education, Office of	34, IV
Civil Rights, Office for	34, I
Educational Research and Improvement, Office of	34, VII
Elementary and Secondary Education, Office of	34, II
Federal Acquisition Regulation	48, 34
Postsecondary Education, Office of	34, VI
Secretary of Education, Office of	34, Subtitle A
Special Education and Rehabilitative Services, Office of	34, III
Educational Research and Improvement, Office of	34, VII
Election Assistance Commission	2, LVIII; 11, II
Elementary and Secondary Education, Office of	34, II
Emergency Oil and Gas Guaranteed Loan Board	13, V
Emergency Steel Guarantee Loan Board	13, IV
Employee Benefits Security Administration	29, XXV
Employees' Compensation Appeals Board	20, IV
Employees Loyalty Board	5, V
Employment and Training Administration	20, V
Employment Policy, National Commission for	1, IV
Employment Standards Administration	20, VI
Endangered Species Committee	50, IV
Energy, Department of	2, IX; 5, XXIII; 10, II, III, X
Federal Acquisition Regulation	48, 9
Federal Energy Regulatory Commission	5, XXIV; 18, I
Property Management Regulations	41, 109
Energy, Office of	7, XXIX
Engineers, Corps of	33, II; 36, III
Engraving and Printing, Bureau of	31, VI
Environmental Protection Agency	2, XV; 5, LIV; 40, I, IV, VII
Federal Acquisition Regulation	48, 15
Property Management Regulations	41, 115
Environmental Quality, Office of	7, XXXI
Equal Employment Opportunity Commission	5, LXII; 29, XIV
Equal Opportunity, Office of Assistant Secretary for	24, I
Executive Office of the President	3, I
Environmental Quality, Council on	40, V
Management and Budget, Office of	2, Subtitle A; 5, III, LXXVII; 14, VI; 48, 99
National Drug Control Policy, Office of	2, XXXVI; 21, III
National Security Council	32, XXI; 47, II
Science and Technology Policy, Office of	32, XXIV; 47, II
Trade Representative, Office of the United States	15, XX
Export-Import Bank of the United States	2, XXXV; 5, LII; 12, IV

Agency	CFR Title, Subtitle or Chapter
Family Assistance, Office of	45, II
Farm Credit Administration	5, XXXI; 12, VI
Farm Credit System Insurance Corporation	5, XXX; 12, XIV
Farm Service Agency	7, VII, XVIII
Federal Acquisition Regulation	48, 1
Federal Acquisition Security Council	41, 201
Federal Aviation Administration	14, I
Commercial Space Transportation	14, III
Federal Claims Collection Standards	31, IX
Federal Communications Commission	5, XXIX; 47, I
Federal Contract Compliance Programs, Office of	41, 60
Federal Crop Insurance Corporation	7, IV
Federal Deposit Insurance Corporation	5, XXII; 12, III
Federal Election Commission	5, XXXVII; 11, I
Federal Emergency Management Agency	44, I
Federal Employees Group Life Insurance Federal Acquisition Regulation	48, 21
Federal Employees Health Benefits Acquisition Regulation	48, 16
Federal Energy Regulatory Commission	5, XXIV; 18, I
Federal Financial Institutions Examination Council	12, XI
Federal Financing Bank	12, VIII
Federal Highway Administration	23, I, II
Federal Home Loan Mortgage Corporation	1, IV
Federal Housing Enterprise Oversight Office	12, XVII
Federal Housing Finance Agency	5, LXXX; 12, XII
Federal Labor Relations Authority	5, XIV, XLIX; 22, XIV
Federal Law Enforcement Training Center	31, VII
Federal Management Regulation	41, 102
Federal Maritime Commission	46, IV
Federal Mediation and Conciliation Service	29, XII
Federal Mine Safety and Health Review Commission	5, LXXIV; 29, XXVII
Federal Motor Carrier Safety Administration	49, III
Federal Permitting Improvement Steering Council	40, IX
Federal Prison Industries, Inc.	28, III
Federal Procurement Policy Office	48, 99
Federal Property Management Regulations	41, 101
Federal Railroad Administration	49, II
Federal Register, Administrative Committee of	1, I
Federal Register, Office of	1, II
Federal Reserve System	12, II
Board of Governors	5, LVIII
Federal Retirement Thrift Investment Board	5, VI, LXXVI
Federal Service Impasses Panel	5, XIV
Federal Trade Commission	5, XLVII; 16, I
Federal Transit Administration	49, VI
Federal Travel Regulation System	41, Subtitle F
Financial Crimes Enforcement Network	31, X
Financial Research Office	12, XVI
Financial Stability Oversight Council	12, XIII
Fine Arts, Commission of	45, XXI
Fiscal Service	31, II
Fish and Wildlife Service, United States	50, I, IV
Food and Drug Administration	21, I
Food and Nutrition Service	7, II
Food Safety and Inspection Service	9, III
Foreign Agricultural Service	7, XV
Foreign Assets Control, Office of	31, V
Foreign Claims Settlement Commission of the United States	45, V
Foreign Service Grievance Board	22, IX
Foreign Service Impasse Disputes Panel	22, XIV
Foreign Service Labor Relations Board	22, XIV
Foreign-Trade Zones Board	15, IV
Forest Service	36, II
General Services Administration	5, LVII; 41, 105
Contract Appeals, Board of	48, 61
Federal Acquisition Regulation	48, 5
Federal Management Regulation	41, 102

Agency	CFR Title, Subtitle or Chapter
Federal Property Management Regulations	41, 101
Federal Travel Regulation System	41, Subtitle F
General	41, 300
Payment From a Non-Federal Source for Travel Expenses	41, 304
Payment of Expenses Connected With the Death of Certain Employees	41, 303
Relocation Allowances	41, 302
Temporary Duty (TDY) Travel Allowances	41, 301
Geological Survey	30, IV
Government Accountability Office	4, I
Government Ethics, Office of	5, XVI
Government National Mortgage Association	24, III
Grain Inspection, Packers and Stockyards Administration	7, VIII; 9, II
Great Lakes St. Lawrence Seaway Development Corporation	33, IV
Gulf Coast Ecosystem Restoration Council	2, LIX; 40, VIII
Harry S. Truman Scholarship Foundation	45, XVIII
Health and Human Services, Department of	2, III; 5, XLV; 45, Subtitle A
Centers for Medicare & Medicaid Services	42, IV
Child Support Enforcement, Office of	45, III
Children and Families, Administration for	45, II, III, IV, X, XIII
Community Services, Office of	45, X
Family Assistance, Office of	45, II
Federal Acquisition Regulation	48, 3
Food and Drug Administration	21, I
Indian Health Service	25, V
Inspector General (Health Care), Office of	42, V
Public Health Service	42, I
Refugee Resettlement, Office of	45, IV
Homeland Security, Department of	2, XXX; 5, XXXVI; 6, I; 8, I
Coast Guard	33, I; 46, I; 49, IV
Coast Guard (Great Lakes Pilotage)	46, III
Customs and Border Protection	19, I
Federal Emergency Management Agency	44, I
Human Resources Management and Labor Relations Systems	5, XCVII
Immigration and Customs Enforcement Bureau	19, IV
Transportation Security Administration	49, XII
HOPE for Homeowners Program, Board of Directors of	24, XXIV
Housing, Office of, and Multifamily Housing Assistance Restructuring, Office of	24, IV
Housing and Urban Development, Department of	2, XXIV; 5, LXV; 24, Subtitle B
Community Planning and Development, Office of Assistant Secretary for	24, V, VI
Equal Opportunity, Office of Assistant Secretary for	24, I
Federal Acquisition Regulation	48, 24
Federal Housing Enterprise Oversight, Office of	12, XVII
Government National Mortgage Association	24, III
Housing—Federal Housing Commissioner, Office of Assistant Secretary for	24, II, VIII, X, XX
Housing, Office of, and Multifamily Housing Assistance Restructuring, Office of	24, IV
Inspector General, Office of	24, XII
Public and Indian Housing, Office of Assistant Secretary for	24, IX
Secretary, Office of	24, Subtitle A, VII
Housing—Federal Housing Commissioner, Office of Assistant Secretary for	24, II, VIII, X, XX
Housing, Office of, and Multifamily Housing Assistance Restructuring, Office of	24, IV
Immigration and Customs Enforcement Bureau	19, IV
Immigration Review, Executive Office for	8, V
Independent Counsel, Office of	28, VII
Independent Counsel, Offices of	28, VI
Indian Affairs, Bureau of	25, I, V
Indian Affairs, Office of the Assistant Secretary	25, VI

Agency	CFR Title, Subtitle or Chapter
Indian Arts and Crafts Board	25, II
Indian Health Service	25, V
Industry and Security, Bureau of	15, VII
Information Resources Management, Office of	7, XXVII
Information Security Oversight Office, National Archives and Records Administration	32, XX
Inspector General	
Agriculture Department	7, XXVI
Health and Human Services Department	42, V
Housing and Urban Development Department	24, XII, XV
Institute of Peace, United States	22, XVII
Inter-American Foundation	5, LXIII; 22, X
Interior, Department of	2, XIV
American Indians, Office of the Special Trustee	25, VII
Endangered Species Committee	50, IV
Federal Acquisition Regulation	48, 14
Federal Property Management Regulations System	41, 114
Fish and Wildlife Service, United States	50, I, IV
Geological Survey	30, IV
Indian Affairs, Bureau of	25, I, V
Indian Affairs, Office of the Assistant Secretary	25, VI
Indian Arts and Crafts Board	25, II
Land Management, Bureau of	43, II
National Indian Gaming Commission	25, III
National Park Service	36, I
Natural Resource Revenue, Office of	30, XII
Ocean Energy Management, Bureau of	30, V
Reclamation, Bureau of	43, I
Safety and Environmental Enforcement, Bureau of	30, II
Secretary of the Interior, Office of	2, XIV; 43, Subtitle A
Surface Mining Reclamation and Enforcement, Office of	30, VII
Internal Revenue Service	26, I
International Boundary and Water Commission, United States and Mexico, United States Section	22, XI
International Development, United States Agency for	22, II
Federal Acquisition Regulation	48, 7
International Development Cooperation Agency, United States	22, XII
International Development Finance Corporation, U.S.	5, XXXIII; 22, VII
International Joint Commission, United States and Canada	22, IV
International Organizations Employees Loyalty Board	5, V
International Trade Administration	15, III; 19, III
International Trade Commission, United States	19, II
Interstate Commerce Commission	5, XL
Investment Security, Office of	31, VIII
James Madison Memorial Fellowship Foundation	45, XXIV
Japan–United States Friendship Commission	22, XVI
Joint Board for the Enrollment of Actuaries	20, VIII
Justice, Department of	2, XXVIII; 5, XXVIII; 28, I, XI; 40, IV
Alcohol, Tobacco, Firearms, and Explosives, Bureau of	27, II
Drug Enforcement Administration	21, II
Federal Acquisition Regulation	48, 28
Federal Claims Collection Standards	31, IX
Federal Prison Industries, Inc.	28, III
Foreign Claims Settlement Commission of the United States	45, V
Immigration Review, Executive Office for	8, V
Independent Counsel, Offices of	28, VI
Prisons, Bureau of	28, V
Property Management Regulations	41, 128
Labor, Department of	2, XXIX; 5, XLII
Benefits Review Board	20, VII
Employee Benefits Security Administration	29, XXV
Employees' Compensation Appeals Board	20, IV
Employment and Training Administration	20, V
Federal Acquisition Regulation	48, 29

Agency	CFR Title, Subtitle or Chapter
Federal Contract Compliance Programs, Office of	41, 60
Federal Procurement Regulations System	41, 50
Labor-Management Standards, Office of	29, II, IV
Mine Safety and Health Administration	30, I
Occupational Safety and Health Administration	29, XVII
Public Contracts	41, 50
Secretary of Labor, Office of	29, Subtitle A
Veterans' Employment and Training Service, Office of the Assistant Secretary for	41, 61; 20, IX
Wage and Hour Division	29, V
Workers' Compensation Programs, Office of	20, I, VI
Labor-Management Standards, Office of	29, II, IV
Land Management, Bureau of	43, II
Legal Services Corporation	45, XVI
Libraries and Information Science, National Commission on	45, XVII
Library of Congress	36, VII
Copyright Royalty Board	37, III
U.S. Copyright Office	37, II
Management and Budget, Office of	5, III, LXXVII; 14, VI; 48, 99
Marine Mammal Commission	50, V
Maritime Administration	46, II
Merit Systems Protection Board	5, II, LXIV
Micronesian Status Negotiations, Office for	32, XXVII
Military Compensation and Retirement Modernization Commission	5, XCIX
Millennium Challenge Corporation	22, XIII
Mine Safety and Health Administration	30, I
Minority Business Development Agency	15, XIV
Miscellaneous Agencies	1, IV
Monetary Offices	31, I
Morris K. Udall Scholarship and Excellence in National Environmental Policy Foundation	36, XVI
Museum and Library Services, Institute of	2, XXXI
National Aeronautics and Space Administration	2, XVIII; 5, LIX; 14, V
Federal Acquisition Regulation	48, 18
National Agricultural Library	7, XLI
National Agricultural Statistics Service	7, XXXVI
National and Community Service, Corporation for	2, XXII; 45, XII, XXV
National Archives and Records Administration	2, XXVI; 5, LXVI; 36, XII
Information Security Oversight Office	32, XX
National Capital Planning Commission	1, IV, VI
National Counterintelligence Center	32, XVIII
National Credit Union Administration	5, LXXXVI; 12, VII
National Crime Prevention and Privacy Compact Council	28, IX
National Drug Control Policy, Office of	2, XXXVI; 21, III
National Endowment for the Arts	2, XXXII
National Endowment for the Humanities	2, XXXIII
National Foundation on the Arts and the Humanities	45, XI
National Geospatial-Intelligence Agency	32, I
National Highway Traffic Safety Administration	23, II, III; 47, VI; 49, V
National Imagery and Mapping Agency	32, I
National Indian Gaming Commission	25, III
National Institute of Food and Agriculture	7, XXXIV
National Institute of Standards and Technology	15, II; 37, IV
National Intelligence, Office of Director of	5, IV; 32, XVII
National Labor Relations Board	5, LXI; 29, I
National Marine Fisheries Service	50, II, IV
National Mediation Board	5, CI; 29, X
National Oceanic and Atmospheric Administration	15, IX; 50, II, III, IV, VI
National Park Service	36, I
National Railroad Adjustment Board	29, III
National Railroad Passenger Corporation (AMTRAK)	49, VII
National Science Foundation	2, XXV; 5, XLIII; 45, VI
Federal Acquisition Regulation	48, 25
National Security Council	32, XXI; 47, II

Agency	CFR Title, Subtitle or Chapter
National Technical Information Service	15, XI
National Telecommunications and Information Administration	15, XXIII; 47, III, IV, V
National Transportation Safety Board	49, VIII
Natural Resource Revenue, Office of	30, XII
Natural Resources Conservation Service	7, VI
Navajo and Hopi Indian Relocation, Office of	25, IV
Navy, Department of	32, VI
Federal Acquisition Regulation	48, 52
Neighborhood Reinvestment Corporation	24, XXV
Northeast Interstate Low-Level Radioactive Waste Commission	10, XVIII
Nuclear Regulatory Commission	2, XX; 5, XLVIII; 10, I
Federal Acquisition Regulation	48, 20
Occupational Safety and Health Administration	29, XVII
Occupational Safety and Health Review Commission	29, XX
Ocean Energy Management, Bureau of	30, V
Oklahoma City National Memorial Trust	36, XV
Operations Office	7, XXVIII
Patent and Trademark Office, United States	37, I
Payment From a Non-Federal Source for Travel Expenses	41, 304
Payment of Expenses Connected With the Death of Certain Employees	41, 303
Peace Corps	2, XXXVII; 22, III
Pennsylvania Avenue Development Corporation	36, IX
Pension Benefit Guaranty Corporation	29, XL
Personnel Management, Office of	5, I, IV, XXXV; 45, VIII
Federal Acquisition Regulation	48, 17
Federal Employees Group Life Insurance Federal Acquisition Regulation	48, 21
Federal Employees Health Benefits Acquisition Regulation	48, 16
Human Resources Management and Labor Relations Systems, Department of Homeland Security	5, XCVII
Pipeline and Hazardous Materials Safety Administration	49, I
Postal Regulatory Commission	5, XLVI; 39, III
Postal Service, United States	5, LX; 39, I
Postsecondary Education, Office of	34, VI
President's Commission on White House Fellowships	1, IV
Presidential Documents	3
Presidio Trust	36, X
Prisons, Bureau of	28, V
Privacy and Civil Liberties Oversight Board	6, X
Procurement and Property Management, Office of	7, XXXII
Public and Indian Housing, Office of Assistant Secretary for	24, IX
Public Contracts, Department of Labor	41, 50
Public Health Service	42, I
Railroad Retirement Board	20, II
Reclamation, Bureau of	43, I
Refugee Resettlement, Office of	45, IV
Relocation Allowances	41, 302
Research and Innovative Technology Administration	49, XI
Rural Business-Cooperative Service	7, XVIII, XLII, L
Rural Development Administration	7, XLII
Rural Housing Service	7, XVIII, XXXV, L
Rural Utilities Service	7, XVII, XVIII, XLII, L
Safety and Environmental Enforcement, Bureau of	30, II
Science and Technology Policy, Office of	32, XXIV; 47, II
Secret Service	31, IV
Securities and Exchange Commission	5, XXXIV; 17, II
Selective Service System	32, XVI
Small Business Administration	2, XXVII; 13, I
Smithsonian Institution	36, V
Social Security Administration	2, XXIII; 20, III; 48, 23
Soldiers' and Airmen's Home, United States	5, XI
Special Counsel, Office of	5, VIII
Special Education and Rehabilitative Services, Office of	34, III
State, Department of	2, VI; 22, I; 28, XI

Agency	CFR Title, Subtitle or Chapter
Federal Acquisition Regulation	48, 6
Surface Mining Reclamation and Enforcement, Office of	30, VII
Surface Transportation Board	49, X
Susquehanna River Basin Commission	18, VIII
Tennessee Valley Authority	5, LXIX; 18, XIII
Trade Representative, United States, Office of	15, XX
Transportation, Department of	2, XII; 5, L
Commercial Space Transportation	14, III
Emergency Management and Assistance	44, IV
Federal Acquisition Regulation	48, 12
Federal Aviation Administration	14, I
Federal Highway Administration	23, I, II
Federal Motor Carrier Safety Administration	49, III
Federal Railroad Administration	49, II
Federal Transit Administration	49, VI
Great Lakes St. Lawrence Seaway Development Corporation	33, IV
Maritime Administration	46, II
National Highway Traffic Safety Administration	23, II, III; 47, IV; 49, V
Pipeline and Hazardous Materials Safety Administration	49, I
Secretary of Transportation, Office of	14, II; 49, Subtitle A
Transportation Statistics Bureau	49, XI
Transportation, Office of	7, XXXIII
Transportation Security Administration	49, XII
Transportation Statistics Bureau	49, XI
Travel Allowances, Temporary Duty (TDY)	41, 301
Treasury, Department of the	2, X; 5, XXI; 12, XV; 17, IV; 31, IX
Alcohol and Tobacco Tax and Trade Bureau	27, I
Community Development Financial Institutions Fund	12, XVIII
Comptroller of the Currency	12, I
Customs and Border Protection	19, I
Engraving and Printing, Bureau of	31, VI
Federal Acquisition Regulation	48, 10
Federal Claims Collection Standards	31, IX
Federal Law Enforcement Training Center	31, VII
Financial Crimes Enforcement Network	31, X
Fiscal Service	31, II
Foreign Assets Control, Office of	31, V
Internal Revenue Service	26, I
Investment Security, Office of	31, VIII
Monetary Offices	31, I
Secret Service	31, IV
Secretary of the Treasury, Office of	31, Subtitle A
Truman, Harry S. Scholarship Foundation	45, XVIII
United States Agency for Global Media	22, V
United States and Canada, International Joint Commission	22, IV
United States and Mexico, International Boundary and Water Commission, United States Section	22, XI
U.S. Copyright Office	37, II
U.S. Office of Special Counsel	5, CII
Utah Reclamation Mitigation and Conservation Commission	43, III
Veterans Affairs, Department of	2, VIII; 38, I
Federal Acquisition Regulation	48, 8
Veterans' Employment and Training Service, Office of the Assistant Secretary for	41, 61; 20, IX
Vice President of the United States, Office of	32, XXVIII
Wage and Hour Division	29, V
Water Resources Council	18, VI
Workers' Compensation Programs, Office of	20, I, VII
World Agricultural Outlook Board	7, XXXVIII

List of CFR Sections Affected

All changes in this volume of the Code of Federal Regulations (CFR) that were made by documents published in the FEDERAL REGISTER since January 1, 2017 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, parts and subparts as well as sections for revisions.

For changes to this volume of the CFR prior to this listing, consult the annual edition of the monthly List of CFR Sections Affected (LSA). The LSA is available at *www.govinfo.gov*. For changes to this volume of the CFR prior to 2001, see the ''List of CFR Sections Affected, 1949–1963, 1964–1972, 1973–1985, and 1986–2000'' published in 11 separate volumes. The ''List of CFR Sections Affected 1986–2000'' is available at *www.govinfo.gov*.

2017

30 CFR

82 FR
Page

Chapter II

Chapter II Policy statement 50532
250.171 Introductory text revised 26744
250.180 (a)(1), (b), (d), (e), (g) and (j) revised 26744
250.1403 Revised 9138

Chapter IV

Chapter IV Policy statement 50532

Chapter V

Chapter V Policy statement 50532
550.1403 Revised 10711
553.51 (a) revised 10711
583 Added 45973

2018

30 CFR

83 FR
Page

Chapter II

250.198 (g)(6) removed; (g) introductory text, (1), (2), (3), (h)(1), (52), (55), (59), (60), (61), (65), (68), (70), (71), and (96) revised; (g)(4) and (5) redesignated as new (g)(6) and (7); new (g)(4), new (5), and (o) added; new (g)(6), new (7), (h)(58), (62), and (73) amended 49255
250.800 (a) revised 49256
250.801 (a) revised 49256

30 CFR—Continued

83 FR
Page

Chapter II—Continued

250.802 (a), (c), and (d) revised 49256
250.803 Revised 49256
250.814 (d) revised 49257
250.820 Revised 49257
250.821 (a) introductory text and (1) revised 49257
250.828 (c) revised 49257
250.833 Introductory text revised 49257
250.834 Revised 49257
250.836 Revised 49257
250.837 (a), (b), and (c)(5) revised 49257
250.841 (c) added 49257
250.842 Revised 49257
250.851 (a)(2) revised 49259
250.852 (e)(1) and (4) revised 49259
250.853 (b) and (c) amended; (d) added 49259
250.867 (a) revised; (d) added 49259
250.870 (a) introductory text and (a)(2) revised 49259
250.872 Revised 49259
250.873 (b)(3) revised 49260
250.874 (g)(2) revised 49262
250.876 Revised 49262
250.880 (a) introductory text, (1), (c)(1)(i), (2)(iv), (4)(i), and (iii) revised 49262
250.1002 (b)(1), (2), and (4) revised 49263
250.1007 (a)(4)(i)(D) revised 49263

30 CFR—Continued

83 FR Page

Chapter II—Continued
250.1403 Revised 2540
Chapter V
550.1403 Revised 8933
553.51 (a) revised 8933
553.702 Revised 2542

2019

30 CFR

84 FR Page

Chapter II
250 Policy statement 55861
250.115 Added; eff. 7–15–19 21968
250.198 Revised; eff. 7–15–19 21969
250.292 (p) revised; eff. 7–15–19 21973
250.413 (g) revised; eff. 7–15–19 21973
250.414 (c)(2) and (3) revised; eff. 7–15–19 21973
250.420 (a)(6) revised; eff. 7–15–19 21973
250.421 (c) through (f) revised; eff. 7–15–19 21974
250.423 (a) and (b) revised; eff. 7–15–19 21974
250.427 (b) revised; eff. 7–15–19 21974
250.428 (c) and (d) revised; eff. 7–15–19 21974
250.433 (b) revised; eff. 7–15–19 21975
250.461 (b) revised; eff. 7–15–19 21975
250.462 (b) introductory text, (e)(1)(ii), (2)(i), (3), and (4) revised; eff. 7–15–19 21975
250.518 (e)(1) revised; (g) added; eff. 7–15–19 21976
250.519 Revised; eff. 7–15–19 21976
250.522 Revised; eff. 7–15–19 21976
250.525 (d) revised; eff. 7–15–19 21976
250.526 Revised; eff. 7–15–19 21976
250.530 (b) revised; eff. 7–15–19 21976
250.601 Amended; eff. 7–15–19 21976
250.616 Removed; eff. 7–15–19 21976
250.619 (e)(1) revised; (g) added; eff. 7–15–19 21976
250.712 (g) and (h) added; eff. 7–15–19 21976
250.720 (a)(1) revised; (a)(3) and (d) added; eff. 7–15–19 21976
250.722 (a)(2) revised; eff. 7–15–19 21977
250.723 Introductory text and (c)(3) revised; eff. 7–15–19 21977
250.724 Revised; eff. 7–15–19 21977
250.730 Revised; eff. 7–15–19 21977
250.731 (a)(5) and (c) revised; (d) and (f) removed; (e) redesignated as new (d); eff. 7–15–19 21978

30 CFR—Continued

84 FR Page

Chapter II—Continued
250.732 Revised; eff. 7–15–19 21978
250.733 (a)(1) and (b)(1) revised; (e) added; eff. 7–15–19 21979
250.734 (a)(6)(vi) removed; (a)(1)(ii), (3), (4), (6)(v), (16), and (b) revised; eff. 7–15–19 21980
250.735 (a) revised; eff. 7–15–19 21981
250.736 (d)(5) revised; eff. 7–15–19 21981
250.737 (a)(4) redesignated as (a)(5); new (a)(4) and (d)(13) added; (b) introductory text, (2), (3), (c), (d)(2)(ii), (3)(iii), (iv), (v), (4)(i), (iii), (v), (5), (10), (12)(iv), and (vi) revised; (d)(4)(vi) removed; eff. 7–15–19 21981
250.738 (b) introductory text, (3), (4), (f), (i), (m), and (o) revised; eff. 7–15–19 21983
250.739 (b) introductory text revised; eff. 7–15–19 21983
250.750—250.751 Undesignated center heading added; eff. 7–15–19 21983
250.750 Added; eff. 7–15–19 21983
250.751 Added; eff. 7–15–19 21984
250.760 Undesignated center heading and section added; eff. 7–15–19 21984
250.842 Revised 24705
250.851 (a)(2) revised 24706
250.873 (b)(3) revised 24707
250.1403 Revised 10992
250.1703 (b) revised; eff. 7–15–19 21984
250.1704 (g)(4) added; (h)(2) revised; eff. 7–15–19 21984
250.1706 Removed; eff. 7–15–19 21985
250.1713 Removed; eff. 7–15–19 21985
250.1716 (b)(3) revised; eff. 7–15–19 21985
250.1722 (d) introductory text revised; eff. 7–15–19 21985
Chapter V
550.1403 Revised 11224
553.51 (a) revised 11224

2020

30 CFR

85 FR Page

Chapter II
250.198 (e)(8), (9), (11), (12), (14), and (16), (20) through (24), (26) through (28), (34), (43) through (46), (50) and (55) revised 84236

30 CFR—Continued

85 FR Page

Chapter II—Continued
250.1203 (b)(4) amended 84237
250.1403 Revised 12735

Chapter V
550.105 Amended; eff. 7–6–20 34935
550.218 (a) introductory text and (e) revised; eff. 7–6–20 34936
550.249 (a) introductory text and (e) revised; (a)(2) amended; eff. 7–6–20 34936
550.283 (a)(4) amended; eff. 7–6–20 34936
550.302 Amended; eff. 7–6–20 34936
550.303 Heading, (d), (e), (f), (h), and (j) heading revised; (a), (b)(1), (c), (g)(1), (2), (i)(B), and (j) amended; eff. 7–6–20 34937
550.304 (b), (c), (d), (e)(1), and (f) heading revised; eff. 7–6–20 34937
550.1403 Revised 7220
553.51 (a) revised 7221

2021

30 CFR

86 FR Page

Chapter II
250.1403 Revised 23608

30 CFR—Continued

86 FR Page

Chapter II—Continued
250.1453 Revised 34134
250.1460 Revised 34134

Chapter V
550.1403 Revised 19784
550.1453 Revised 38559
550.1460 (b) revised 38559
553.51 (a) revised 19784

2022

(Regulations published from January 1, 2022, through July 1, 2022)

30 CFR

87 FR Page

Chapter II
250.125 (a)(1) through (31) revised 19803
250.126 (a) revised 19803
250.1403 Revised 10308

Chapter V
550.1403 Revised 15335
553 Authority citation revised 15335
553.51 (a) revised 15335